10-YEAR TRANSMISSION PLAN

For the State of Colorado

To comply with

Rule 3627

of the

Colorado Public Utilities Commission

Rules Regulating Electric Utilities

February 1, 2018

Table of Contents

ACRONYMS AND ABBREVIATIONS

Acronym or Abbreviation	Term
2018 Plan	2018 10-Year Transmission Plan for the State of Colorado
ALJ	Administrative Law Judge
ARPA	Arkansas River Power Authority
ATC	Available Transfer Capability
ATCID	Available Transfer Capability Implementation Document
BES	Bulk Electric System
Black Hills	Black Hills Colorado Electric Utility Company, L.P. d/b/a Black Hills Energy
BHCE	Black Hills Colorado Electric Utility Company, L.P.
BHCT	Black Hills/Colorado Transmission
CBM	Capacity Benefit Margin
CBMID	Capacity Benefit Margin Implementation Document
CCOD	City and County of Denver
CCPG	Colorado Coordinated Planning Group
CDOT	Colorado Department of Transportation
CEII	Critical Energy Infrastructure Information
CEO	Colorado Energy Office
Commission or CPUC	Colorado Public Utilities Commission
Companies	Black Hills, Tri-State and Public Service
Company	Black Hills, Tri-State or Public Service
CPCN	Certificate of Public Convenience and Necessity
CPP	Clean Power Plan
CSU	Colorado Springs Utilities
DSM	Demand-Side Management
EPA	Environmental Protection Agency
EPAct	Energy Policy Act of 2005
ERP	Electric Resource Plan
ERP/APR	Electric Resource Plan Annual Progress Report

Acronym or Abbreviation	Term
ERZ	Energy Resource Zone
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
HOA	Homeowners Association
HVDC	High Voltage Direct Current
IREA	Intermountain Rural Electric Association
KCEA	K.C. Electric Association
kV	Kilovolt
L&R	Load and Resource
LGIP	Large Generator Interconnection Procedures
LRCC	Loveland Reliability Control Center
LTP	Local Transmission Plan
MEAN	Municipal Electric Agency of Nebraska
MW	Megawatts
MVAR	Mega Volt Ampere Reactive
MVEA	Mountain View Electric Association
NECO	Northeast Colorado
NERC	North American Electric Reliability Corporation
NREL	U.S. Department of Energy's National Renewable Energy Laboratory
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OCC	Colorado Office of Consumer Counsel
Order 1000	FERC Order No. 1000 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities
PA	Planning Authority
PNM	Public Service Company of New Mexico
PRPA	Platte River Power Authority
PST	Phase Shifting Transformer

Acronym or Abbreviation	Term
Public Service	Public Service Company of Colorado
RAC	Reliability Assessment Committee
RCTF	Rush Creek Task Force
RES	Renewable Energy Standard
RTO	Regional Transmission Organization
SB07-100	Colorado Senate Bill 07-100
Sierra	Sierra Subregional Planning Group
SLV	San Luis Valley
SOL	System Operating Limits
SPG	Sub-regional planning group
SPP	Southwest Power Pool
SWAT	Southwest Area Transmission Group
SWEP	Southwest Weld Expansion Project
TBD	To Be Determined
TCPC	Transmission Coordination and Planning Committee
TP	Transmission Provider
Tri-State	Tri-State Generation and Transmission Association, Inc.
TRMID	Transmission Reliability Margin Implementation Document
TTC	Total Transfer Capability
WECC	Western Electricity Coordinating Council
Western/WAPA	Western Area Power Administration (also WAPA)

I. Executive Summary

The purpose of transmission planning is to ensure the present and future reliability of the interconnected bulk electric transmission system. Planning is performed to meet customer needs by facilitating the timely and coordinated development of transmission infrastructure projects on a cost-effective and reliable basis. In order to promote an efficient utilization of the transmission system, planning also takes into account drivers such as public policy initiatives, environmental concerns, and stakeholder interests, which are collected via numerous meaningful input opportunities throughout the planning process.

In 2011, the Colorado Public Utilities Commission ("Commission" or "CPUC") adopted Rules 3625 through 3627, which set forth requirements for transmission planning applicable to Commission-regulated utilities. The rules require these utilities to establish a process to coordinate the planning of additional electric transmission in Colorado in a comprehensive and transparent manner. The process is to be conducted on a statewide basis and is to take into account the needs of all stakeholders. This 2018 10-Year Transmission Plan for the State of Colorado ("2018 Plan") is the result of a cooperative effort among Black Hills Colorado Electric Utility Company, L.P. d/b/a Black Hills Energy ("Black Hills"), Tri-State Generation and Transmission Association, Inc. ("Tri-State"), and Public Service Company of Colorado ("Public Service") (each a "Company" and collectively the "Companies"), and is the fourth 10-Year transmission plan that the Companies have filed under Rule 3627.

Since filing the first 10-Year transmission plan in 2012, the Companies have continued to coordinate the transmission planning process with all Colorado Transmission Providers ("TPs") and interested stakeholders through active outreach efforts and coordinated planning activities in a variety of transmission planning venues. The 2018 Plan is the culmination of a collaborative process and includes transmission facilities that the Companies, individually or jointly, may construct or participate in over the next ten years in the state of Colorado. The 2018 Plan includes two types of projects. "Planned Projects" are projects for which the companies generally have a level of commitment such that proposed schedules for completion have been drafted, site control has been established or the

project has received budgetary approvals. These include projects that are required to meet reliability and load growth needs, planned interconnection of new generation, or to meet enacted public policy requirements. “Conceptual Projects,” on the other hand, may not have specific in-service dates, and their implementation depends on numerous factors, some of which include forecasted load growth and generation needs, economic considerations, public policy initiatives, and regional transmission development.

The Companies are confident that the 2018 Plan and the individual transmission projects included in the 2018 Plan meet all applicable reliability criteria and do not negatively impact the system of any other TP or the overall transmission system in the near-term and long-term planning horizons. Projects included in the 2018 Plan do not duplicate existing or planned transmission facilities of any other transmission provider in Colorado. Finally, the Companies are confident that the coordination and stakeholder outreach processes described herein have effectively solicited and addressed the interests of stakeholders.

When possible, individual transmission projects have been designed to accommodate the collective needs of multiple TPs and stakeholders. Changes in regulatory requirements, regulatory approvals, or underlying assumptions such as load forecasts, generation, or transmission expansions, economic issues, and other utilities’ plans may impact this 2018 Plan and could result in changes to in-service dates or project scopes.

Public policy initiatives, such as future federal and local mandates, may also impact the 2018 Plan and the transmission planning process in general. Examples of public policies potentially impacting the Companies include Colorado’s Renewable Energy Standard, Senate Bill 07-100, and the U.S. Environmental Protection Agency’s (“EPA”) Clean Power Plan (“CPP”) and any associated Colorado state compliance plan. The final federal rules implementing the CPP were published in the Federal Register on October 23, 2015; however, the CPP encountered various legal challenges and in February 2016, the U.S. Supreme Court stayed implementation of the CPP. As a result, the CPP has not gone into effect and no Colorado state compliance plan has been issued. The EPA has stated that it intends to replace the CPP with new rules and, in December 2017, issued an Advance Notice of Proposed Rulemaking seeking comments on how to reduce carbon emissions

from existing power plants. While the specifics of a CPP replacement remain to be determined, the Companies anticipate that any such regulations may impact transmission plans in the 10-Year planning timeframe. The Companies will continue to coordinate with each other and stakeholders with respect to the transmission planning implications of such new federal regulations and expect to address this issue in the next 10-Year transmission plan.

Section II provides background information about the transmission planning process—including coordinated regional and statewide efforts, as well as internal practices of each Company—while Sections V - VIII address compliance with specific legal, regulatory and technical requirements of Rule 3627 and Federal Energy Regulatory Commission ("FERC") Orders, with an emphasis on stakeholder outreach efforts.

This 2018 Plan identifies 59 significant transmission projects. These projects are listed in Table 1 and shown geographically in Figure 1. Figures 2 and 3 are maps depicting transmission projects in the Denver-Metro area and in Black Hills 10-Year Transmission Plan, respectively. Larger maps of the state plan showing chronological stages of development are provided in Appendix A. Larger versions of the Denver-Metro and Black Hills maps are provided in Appendices B and C.

Sections III and IV of this report provide additional details for these and other projects that the Companies have identified in their transmission planning processes; complete details and supporting information can be found in Appendices D-I.

Table 1. Significant transmission projects included in the 2018 Plan

Map #	Project Name	In-Svc [(1)]	Cost (MIL)	BH	TS	PS	Other	Purpose
1	Cherokee Ridge 230 kV Conversion	2016	$4.7			√		R
2	IREA Happy Canyon Substation	2016	$3.0			√		L
3	Rifle-Parachute 230kV line #2	2016	$28.5			√		R
4	Wolcott 230 kV Substation Reactors	2016	$6.2			√		R
5	Nixon South 2nd Transmission Line	2017	$1.5				CSU	R

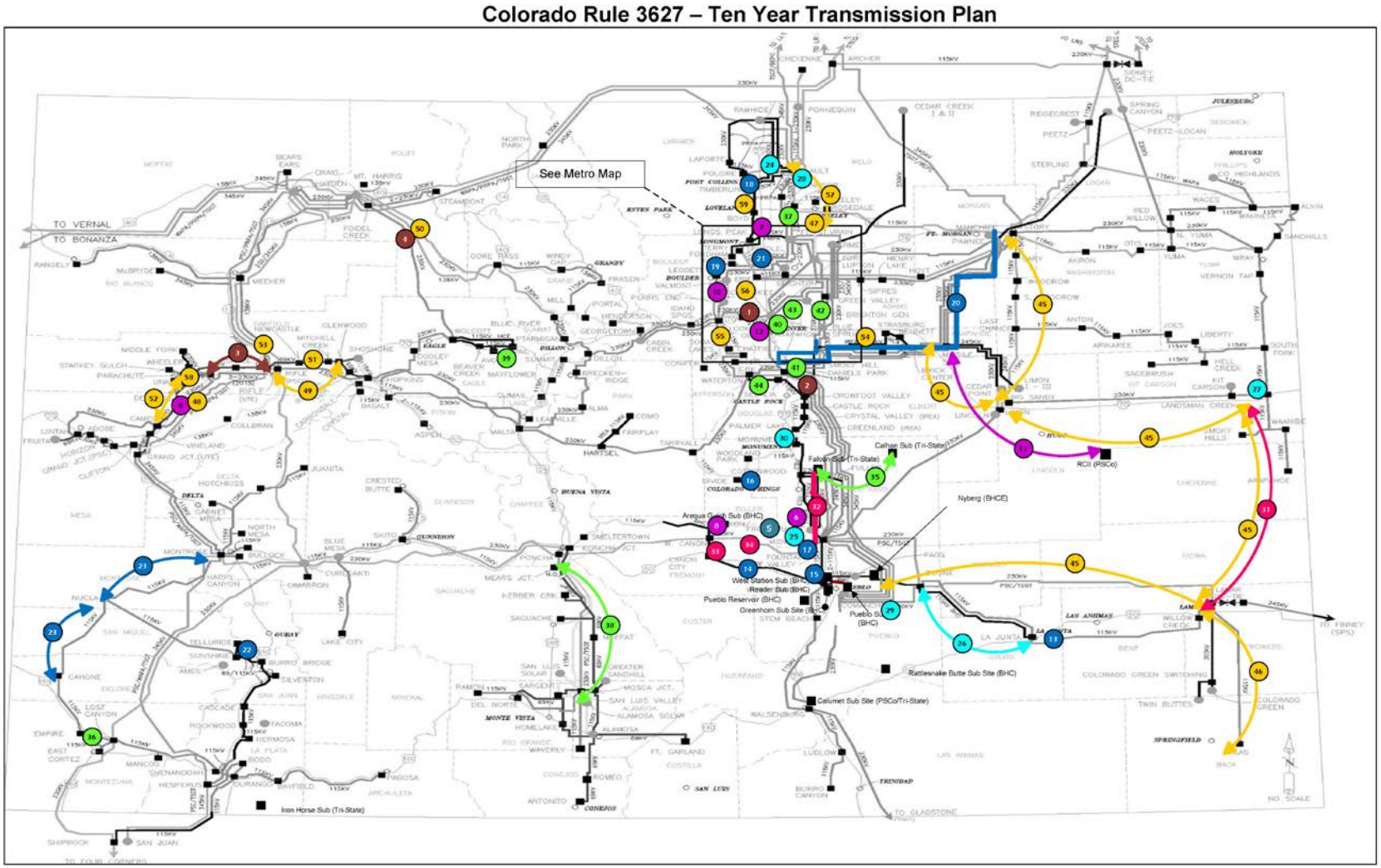
Map #	Project Name	In-Svc [(1)]	Cost (MIL)	BH	TS	PS	Other	Purpose
6	Kelker 3rd 230/115 kV Autotransformer	2018	$1.7				CSU	R
7	Boyd 230/115 kV Substation Expansion	2018	$10.0				PRPA	R
8	Arequa Gulch 115 kV Capacitor	2018	$0.85	√				R
9	Bluestone Valley Substation Phase 1	2018	$7.2			√		R
10	Moon Gulch 230 kV Substation	2018	$1.9			√		L
11	Rush Creek-Missile Site 345 kV Transmission Project	2018	$121.4			√		G
12	Two Basins Relocation Project	2018	$29.1			√		R
13	La Junta 115 kV Area Upgrades	2019	$3.9	√				R
14	Portland 115/69 kV Transformer Replacement	2019	$3.7	√				R
15	West Station 115 kV Substation Upgrades	2019	$6.5	√				R
16	Cottonwood 230/115 kV Autotransformer Replacement	2019	$3.0				CSU	R
17	Series Reactor-Nixon-Fountain 115 kV system	2019	$1.5				CSU	R
18	Avery Substation	2019	$10.3			√		L
19	NREL Substation	2019	$6.7			√		G
20	Pawnee-Daniels Park 345 kV	2019	$178.3			√		G,R
21	Thornton Substation	2019	$24.7			√		L
22	Sunshine-Telluride Line Uprate	2019	$3.1		√			R
23	Western Colorado Trans Upgrade	2019	$120.0		√			R
24	Ault 345/230 kV XFMR Replacement	2020	$7.8				WAPA	R
25	Midway KV1A Replacement	2020	$2.0				WAPA	R
26	Boone-La Junta 115 kV Rebuild	2020	$20.9	√				R
27	Burlington-Burlington (KCEA) Rebuild	2020	$2.3		√			R
28	Ault-Cloverly 230/115 kV Transmission Project	2020	$65.0			√		L,R
29	Badger Hills Substation	2020	$26.6			√		G
30	Monument-Flying Horse 115 kV Phase Shifter	2020	TBD			√		R
31	Burlington-Lamar 230 kV	2021	$54.0		√			G,L,R

Map #	Project Name	In-Svc [(1)]	Cost (MIL)	BH	TS	PS	Other	Purpose
32	Falcon-Midway 115 kV Line Uprate	2021	$5.6		√			R
33	North Cañon 115/69 kV Substation	2021	$9.9	√				L,R
34	West Station-West Cañon 115 kV Transmission Project	2021	$23.0	√				L,R
35	Falcon-Paddock-Calhan 115 kV	2022	$33.4		√			R
36	Lost Canyon-Main Switch 115 kV	2022	$17.8		√			L,R
37	Southwest Weld Expansion Project	2022	$70.0		√			L,R
38	San Luis Valley-Poncha 230 kV #2	2022	$58.0		√	√		R, G
39	Avon-Gilman 115 kV Transmission	2022	$22.9			√		R
40	Barker Distribution Substation	2022	$18.0			√		L
41	Dove Valley Distribution Substation	2022	TBD			√		L
42	High Point Distribution Substation	2022	TBD			√		L
43	Stock Show Distribution Substation	2022	TBD			√		L
44	Titan Distribution Substation	2022	TBD			√		L
45	Lamar Front Range	TBD	$900.0		√	√		G,R
46	Lamar-Vilas 230 kV	TBD	$90.0		√	√		G
47	Weld-Rosedale-Milton 230 kV	TBD	TBD		√	√		L,R
48	Bluestone Valley Substation Phase 2	TBD	TBD			√		L
49	Glenwood-Rifle 115 kV	TBD	TBD			√		L,R
50	Hayden-Foidel-Gore 230 kV	TBD	TBD			√		R
51	New Castle Distribution Substation	TBD	$1.4			√		L
52	Parachute-Cameo 230 kV #2	TBD	$48.0			√		L,R
53	Rifle (Ute)-Story Gulch 230 kV	TBD	TBD			√		L
54	Sandy Creek Distribution Substation	TBD	TBD			√		L
55	Solterra Distribution Substation	TBD	TBD			√		L
56	Superior Distribution Substation	TBD	TBD			√		L
57	Weld County Expansion	TBD	TBD			√		G,R
58	Wheeler-Wolf Ranch 230 kV	TBD	$17.0			√		L
59	Wilson Distribution Substation	TBD	$4.0			√		L

Key: R – Reliability, L – Load-serving, G – Generation, TBD – To Be Determined

Note 1: In service dates are based on best estimates at the time of this filing. Changed needs, load forecasts, permitting activities, timelines for delivery of major equipment, etc. can and will impact project viability and final in-service dates.

Figure 1. Statewide map of significant transmission projects in the 2018 Plan



**All projects are subject to change and routes have yet to be determined.*

2016	2017	2018	2019	2020
1 Cherokee – Ridge 230kV Conversion (New, PSCo)	5 Nixon South 2nd Transmission Line (CSU)	6 Kelker 3rd 230/115kV Autotransformer (CSU)	13 La Junta 115/69kV Transformer #2 (New, BHCE)	24 Ault 345/230kV Transformer Replacement (WAPA)
2 IREA Happy Canyon Substation (New, PSCo)		7 Boyd 230/115kV Substation Expansion (PRPA)	14 Portland 115/69kV Transformer Replacement (Upgrade, BHCE)	25 Midway kV1A Replacement (WAPA)
3 Rifle-Parachute 230kV #2 (New, PSCo)		8 Arequa Gulch 115kV Capacitor (New, BHCE)	15 West Station 115kV Substation Upgrades (Upgrade, BHCE)	26 Boone – La Junta 115kV Rebuild (Upgrade, BHCE)
4 Wolcott 230kV Substation Reactors (PSCo)		9 Bluestone Valley Substation Phase 1 (PSCo)	16 Cottonwood 230/115kV Autotransformer Replacement (CSU)	27 Burlington – Burlington (KCEA) Rebuild (Tri-State)
		10 Moon Gulch 230kV Substation (New, PSCo)	17 Series Reactor – Nixon – Fountain 115kV System (CSU)	28 Ault – Cloverly 230/115kV Transmission Project
		11 Rush Creek – Missile Site 345kV Transmission Project (PSCo)	18 Avery Substation (New, PSCo)	29 Badger Hills Substation
		12 Two Basins Relocation Project (PSCo)	19 NREL Substation	30 Monument – Flying Horse 115kV Phase Shifter
			20 Pawnee – Daniels Park 345Kv	
			21 Thornton Substation (New, PSCo)	
			22 Sunshine – Telluride Line Uprate (Tri-State)	
			23 Western Colorado Transmission Upgrade Project (Upgrade, Tri-State)	

2021	2022	2023		Beyond 2023 or ISD TBD
31 Burlington – Lamar 230kV (Tri-State)	35 Falcon – Paddock – Calhan 115kV (Tri-State)			45 Lamar-Front Range 345kV (Tri-State, PSCo)
32 Falcon-Midway 115kV Uprate (Tri-State)	36 Lost Canyon Main Switch 115kV (New, Tri-State)			46 Lamar-Vilas 230kV (Tri-State, PSCo)
33 North Canon 115/69kV Substation (New, BHCE)	37 Southwest Weld Expansion Project (New, Tri-State)			47 Weld – Rosedale – Milton 230kV (Tri-State, PSCo)
34 W. Station – Canon West 115kV Project (New, BHCE)	38 San Luis Valley – Poncha 230kV #2 (Tri-State, PSCo)			48 Bluestone Valley Substation Phase 2 (New, PSCo)
	39 Avon – Gilman 115kV Transmission (PSCo)			49 Glenwood-Rifle 115kV (Upgrade, PSCo)
	40 Barker Distribution Substation (PSCo)			50 Hayden – Foidel - Gore Loop (Upgrade, PSCo)
	41 Dove Valley Distribution Substation (PSCo)			51 New Castle Distribution Substation (PSCo)
	42 High Point Distribution Substation (PSCo)			52 Parachute–Cameo 230kV #2 (New, PSCo)
	43 Stock Show Distribution Substation (PSCo)			53 Rifle(Ute) – Story Gulch 230kV (New, PSCo)
	44 Titan Distribution Substation (PSCo)			54 Sandy Creek Distribution Substation (PSCo)
				55 Solterra Distribution Substation (PSCo)
				56 Superior Distribution Substation (PSCo)
				57 Weld County Expansion (New, PSCo)
				58 Wheeler – Wolf Ranch 230kV (New, PSCo)
				59 Wilson Substation (New, PSCo)

Figure 2. Denver-Metro map of transmission projects in the 2018 Plan

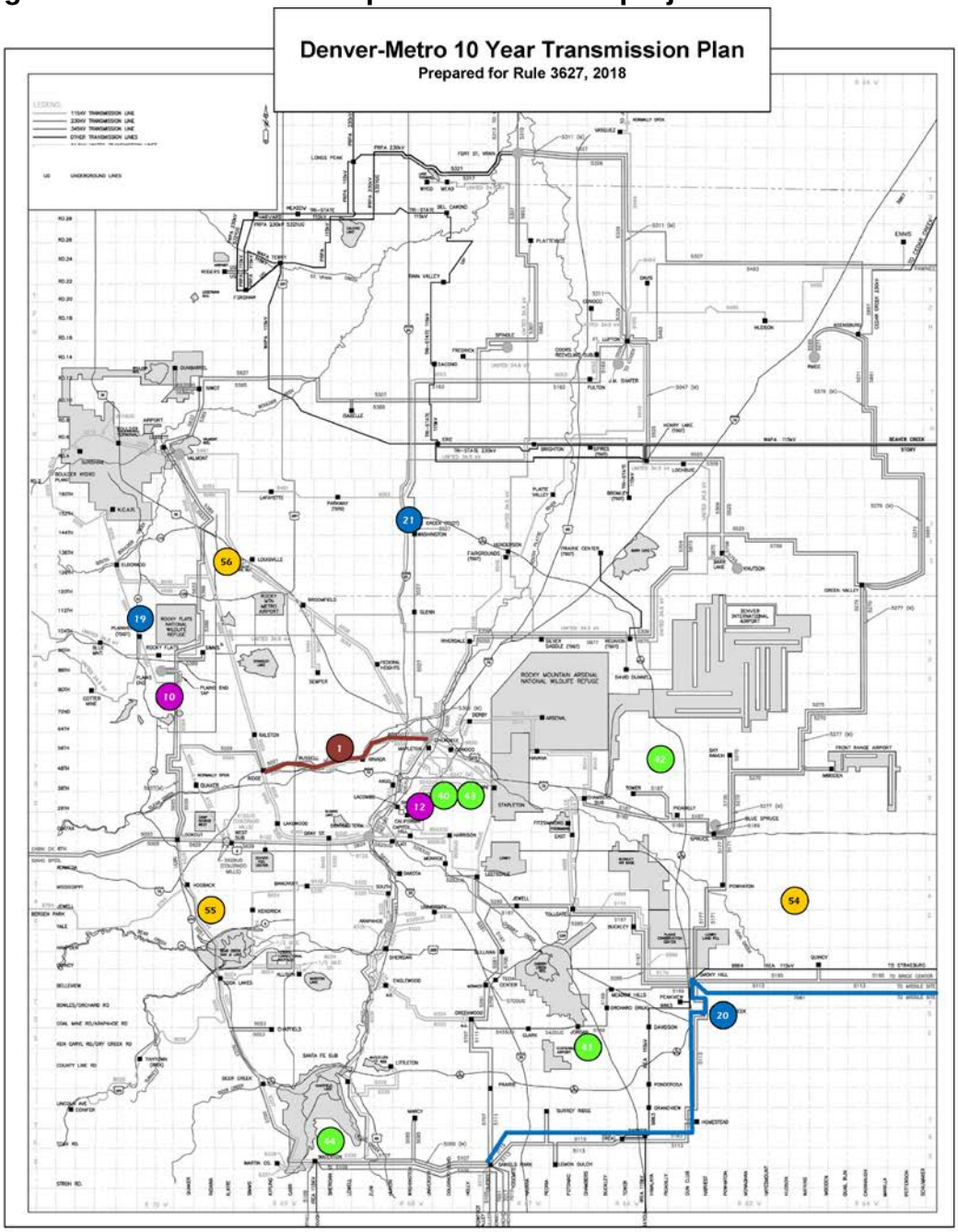
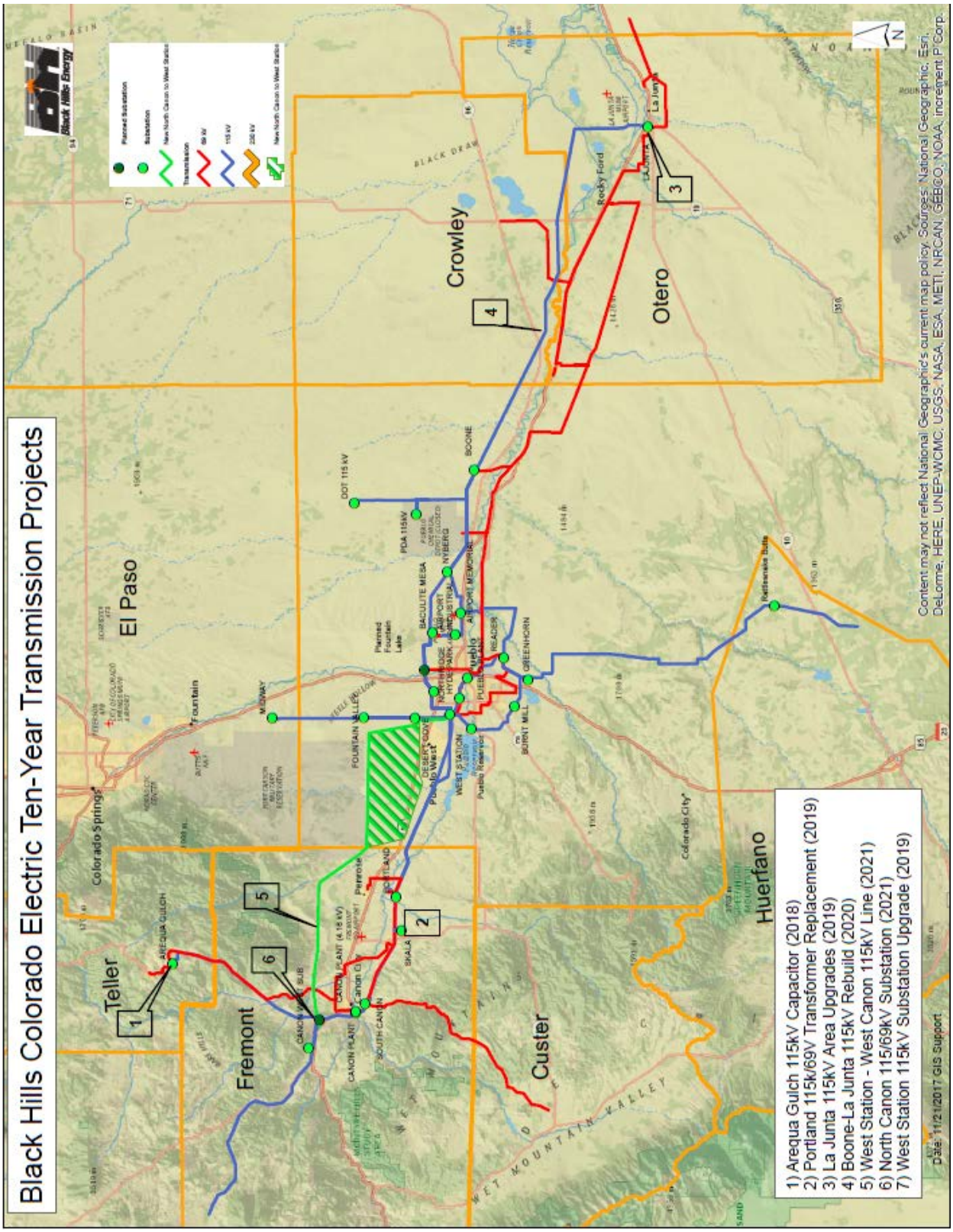


Figure 3. Pueblo area map of transmission projects in the 2018 Plan



II. Transmission Planning in Colorado

A. Coordinated Planning

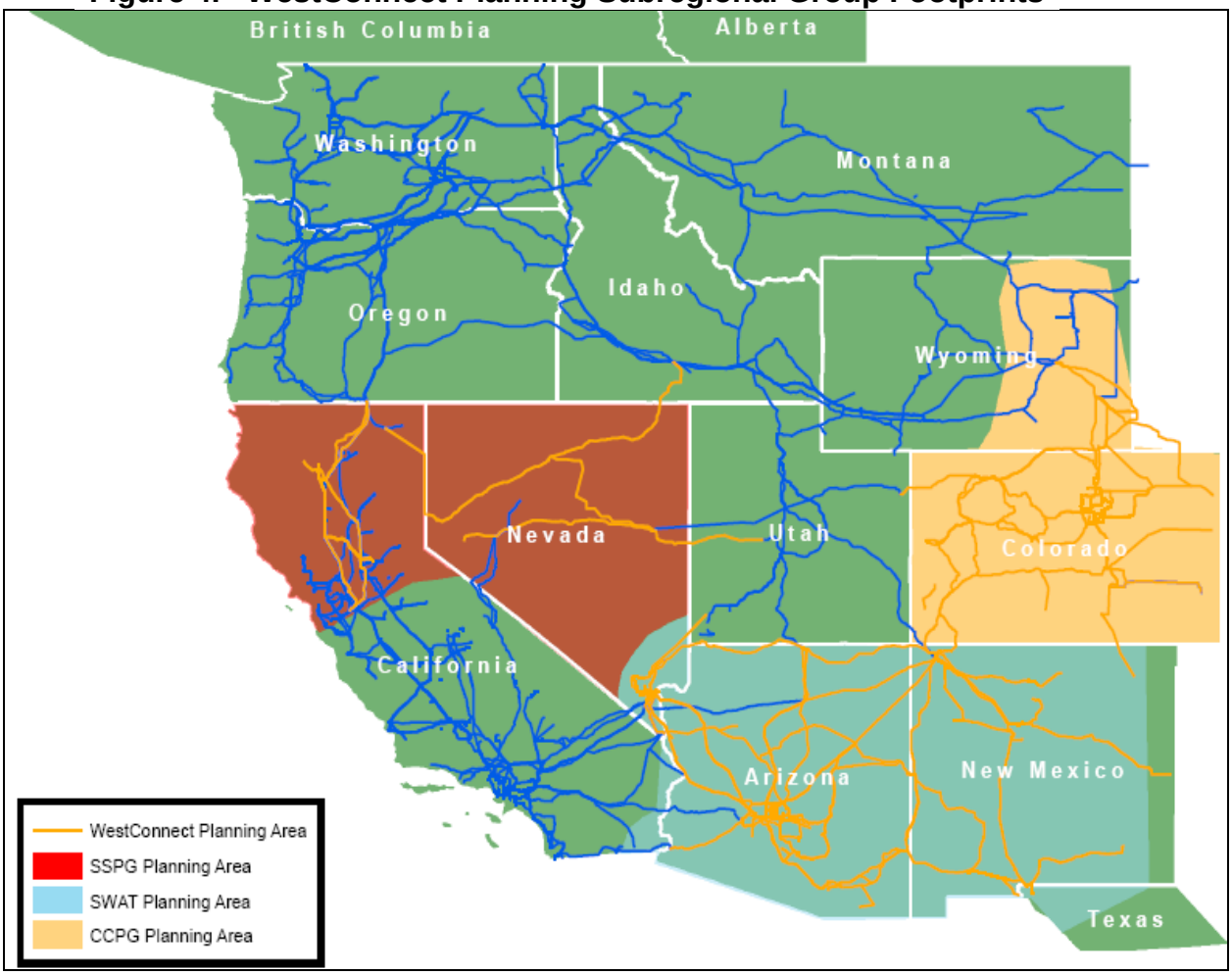
The Companies' transmission planning processes are intended to facilitate the development of electric infrastructure that maintains reliability and meets load growth. Because Colorado does not have a Regional Transmission Organization ("RTO") at this time, each TP in the State is responsible for planning its own transmission system. To ensure that this process is as seamless and efficient as possible, the Companies participate in transmission planning at regional, sub-regional, and local levels.

The Companies are active members and participants in regional and subregional transmission planning organizations, including the Western Electricity Coordinating Council ("WECC"), WestConnect, and the Colorado Coordinated Planning Group ("CCPG"). WECC is the forum responsible for coordinating and promoting Bulk Electric System ("BES") reliability in the entire Western Interconnection.

WestConnect is one of four planning "regions"[2] within WECC established for regional transmission planning to comply with FERC Order No. 1000*, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities* ("Order 1000"). WestConnect includes three sub-regional planning groups ("SPGs"): CCPG, Southwest Area Transmission Group ("SWAT"), and Sierra Subregional Planning Group ("Sierra").

[2] The other three are Columbia Grid, Northern Tier Transmission Group, and the California Independent System Operator.

Figure 4. WestConnect Planning Subregional Group Footprints

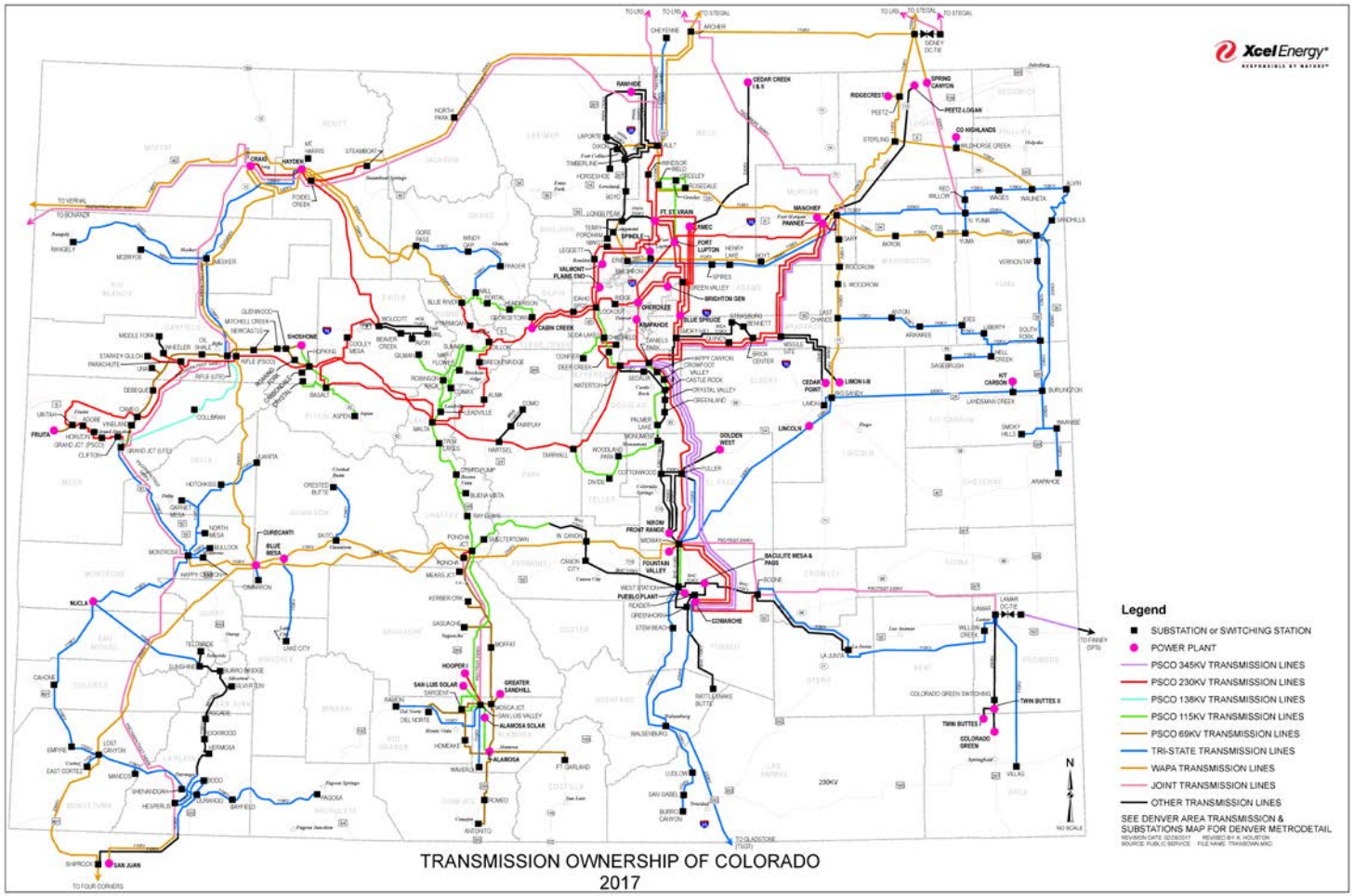


CCPG, which was formed in 1991, is a planning forum that cooperates with state and regional agencies to ensure a high degree of reliability in planning, development and operation of the transmission system in the Rocky Mountain Region. Figure 4 shows the planning areas of the CCPG and other subgroups of WestConnect.

The Companies have a long history of coordinated transmission planning with each other and other Transmission Planners in Colorado. As shown in Figure 5, the Colorado transmission system includes many jointly-owned lines. Given the integrated nature and ownership of the transmission grid in Colorado, coordinated transmission planning has been commonplace in Colorado even before the adoption of Rule 3627.

As part of the Large Generator Interconnection Procedures (“LGIP”), the Companies often coordinate with each other as well as with other TPs in Colorado on the impacts of any proposed generation projects on the transmission system.

Figure 5. Transmission Ownership in the State of Colorado (2017)



Internally, and through WestConnect and CCPG, each Company performs annual system assessments to verify compliance with reliability standards, to determine related system improvements, and to demonstrate adherence to the standards and criteria set forth by North American Electric Reliability Corporation ("NERC") and WECC. Compliance is certified annually.

During the coordinated planning process, a wide range of factors and interests are considered by the Companies, including, but not limited to:

- The needs of network transmission service customers to integrate loads and resources;
- Transmission infrastructure upgrades necessary to interconnect new generation resources;
- The minimum reliability standard requirements promulgated by NERC and WECC;
- Bulk electric system considerations above and beyond the NERC and WECC minimum reliability standard requirements;
- Transmission system operational flexibility, which supports economic dispatch of interconnected generation resources; and
- Various regional and sub-regional transmission projects planned by other utilities and stakeholders.

This comprehensive internal, regional, and sub-regional planning process ensures that transmission plans continue to be carefully coordinated with all TPs in the State of Colorado.

B. Public Policy Issues

In addition to planning for load growth and reliability, Companies must consider proposed and enacted public policy initiatives, such as Colorado's Renewable Energy Standard, Colorado Senate Bill 07-100 ("SB07-100"), and the U.S. EPA potential CPP and any associated Colorado state compliance plan. Two of the Companies, Black Hills

and Public Service, are subject to the requirements of SB07-100 which requires Colorado's rate-regulated electric utilities to identify areas that have a high potential for beneficial resource development. A discussion of SB07-100 and other public policy related planning is included in Section V.

III. Company Plan Narratives

A. Black Hills 10-Year Plan Overview

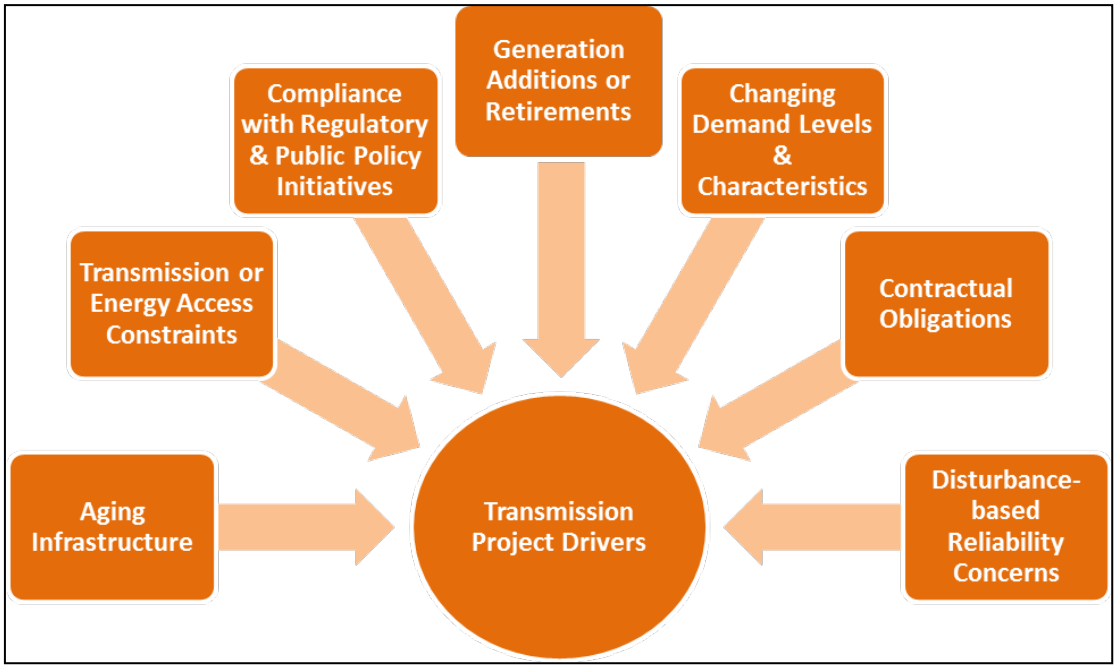
1. Black Hills Service Territory

Black Hills Colorado Electric, a division of Black Hills Corporation, serves over 95,000 customers in south-central Colorado. The counties served are parts of Crowley, Custer, El Paso, Fremont, Otero, Pueblo, and Teller. Twenty-one communities are served, and of these, the largest communities are Pueblo, Cañon City, and Rocky Ford. Black Hills Planning Process.

The Black Hills planning process emphasizes education, participation, and coordination, with the ultimate goal of contributing to the development of an optimal long-term road map for transmission development in Colorado, consistent with Rule 3627.

Throughout its transmission planning process, Black Hills considers a number of variables and inputs, the first of which is a specific need or set of needs that drive the development of a certain project. Figure 6 shows a selection of needs that commonly give rise to projects within the Company's planning horizon.

Figure 6. Needs that Drive Transmission Development



Needs may arise from a single entity, or they may coincide with the needs of multiple entities, in which case a joint project may be appropriate. Once a need has been identified, Company planners begin searching for a solution. As solution alternatives are developed, the following considerations may come into play:

Adequacy of each alternative to meet the specified need

- Potential of each alternative to augment or inhibit potential future projects
- Cost of implementation and availability of project funding
- Required implementation schedule
- Environmental and societal impacts
- Project life expectancy
- Tangible benefits to customers
- Geographic and physical constraints
- Ability to integrate with existing and planned transmission projects
- Impact to telecom, transportation, and other energy-related networks

Black Hills transmission planners, through coordination with the stakeholder community, evaluate the weight of the above considerations to determine the best overall solution to the identified need, ensuring that the solution is financially prudent, publicly acceptable and physically feasible. Often a small subset of these factors will comprise a majority of the justification for a project.

Because communication and stakeholder participation is critical at all stages of planning, Black Hills performs its planning process on an annual basis in an open, transparent, coordinated and non-discriminatory fashion to ensure the opportunity for direct participation is offered to all stakeholders. Consistent with FERC Order Nos. 890 and 1000, Black Hills promotes participation in the planning process to all interested parties, and coordinates study efforts and results with other utilities as well as regional planning organizations such as West Connect, CCPG, and various groups within WECC.

Planning reliability studies are conducted annually to satisfy NERC and WECC requirements. Additional studies are performed as necessary to address specific purposes including, but not limited to, transmission service requests, generator interconnections, transmission interconnections, load interconnections and transfer capability assessments. This process and related discussions are subject to FERC's Critical Energy Infrastructure Information ("CEII") procedures.

Black Hills planners employ software models representative of the transmission system during the timeframe of interest, including current load and resource information, existing and planned infrastructure, service commitments, facility ratings and parameters, valid disturbance events, and any operating constraints to be observed. Additionally, all guidelines, requirements and applicable criteria, as well as 10-Year load and resource projections (submitted annually by network customers), are reviewed and included in the study plan. These study models allow planners to identify conditions and timeframes during which the transmission system will or will not satisfy all reliability and economic requirements.

If a planning study identifies a deficiency in transmission system performance, various mitigation options are evaluated to determine an optimal solution to meet the long-term needs of all affected parties. Evaluation of each potential project is coordinated with interested stakeholders and neighboring transmission providers to avoid duplication, minimize impacts and the likelihood of unmet obligations, and maximize the overall benefit of a project.

Routine planning is conducted for a wide range of scenarios to evaluate the performance of the transmission system over a 10- to 20-year period. In a given study year, viable system upgrades and transmission initiatives are compiled to create the Black Hills 10-Year Local Transmission Plan, which is evaluated annually and updated as needed to reflect ongoing project needs. Potential changes in reliability requirements, planned generation, transmission, load growth, and regulations require the build-out of a flexible, robust transmission system that meets customer needs under a wide range of foreseeable circumstances within the planning horizon.

2. Black Hills Projects

Black Hills' load growth has increased slightly over the past couple years, driven primarily by large industrial load expansions as well as some commercial load growth. The Black Hills projects included in the 2018 Plan largely reflect the continued strategy of infrastructure upgrades or additions to enhance reliability. Since most of Black Hills' projects are reliability driven equipment replacements or upgrades, the focus on best-cost considerations was narrowed as appropriate.

In the 2018 Plan, which was the result of an open and coordinated planning approach on regional, sub-regional and local levels, Black Hills documents a procedure to address foreseeable local reliability and load service issues. Detailed project information can be found in Appendix D.

Since the filing of the 2016 10-Year Plan, Black Hills has completed five projects and removed them from the current list of significant planned projects: the new Fountain

Lake 115 kV substation, the Boone-Nyberg 115 kV line rebuild, the Baculite Mesa-Fountain Lake 115 kV line rebuild, the Boone 115/69 kV transformer replacement and the Rattlesnake Butte 115 kV terminal addition. Black Hills has identified seven planned projects within the upcoming 10-Year planning horizon that represent $71.2 million in capital expenditures between 2018 and 2021. The projects were identified to increase reliability within Black Hills' network transmission system, to support voltage, and to meet the requirements associated with expected load growth and generation development. The reliability-driven projects are required under various NERC Reliability Standards to address anticipated system performance issues. The projects in this section were coordinated with stakeholders and neighboring entities to ensure the best solution is achieved while avoiding duplication of facilities.

Planned projects are categorized according to the three distinct geographic areas within Black Hills' Colorado service territory.

Cañon City area

Four projects, shown in Table 2, address reliability concerns in the Cañon City area. Local load growth has resulted in the need for additional transformation capacity in the area, as well as additional local voltage support. A new transmission line into the area and one new 115/69 kV substation will improve load service and operational flexibility.

Table 2. Cañon City area projects included in the Black Hills 2018 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Arequa Gulch 115 kV Capacitor	2018	$0.85	Not Required
Portland 115/69 kV Transformer Replacement	2019	$3.7	Not Required
West Station-West Cañon Transmission Line	2021	$23.0	Not Required
North Cañon 115/69 kV Substation	2021	$9.9	Not Required

The Black Hills planning process identified the solution for expected voltage concerns resulting from anticipated load growth at Arequa Gulch as the addition of a 12-MVAR 115 kV capacitor.

Additionally, new 115/69 kV transformers at Portland are planned to replace the two existing transformers. The transformers may reach their thermal limits under certain operating conditions and will be replaced with a larger units to provide the required capacity. The replacement of the second unit at Portland remains under review to determine if a more beneficial solution is available. Because the projects in this area were found to be in the ordinary course of business, Certificate of Public Convenience and Necessity's ("CPCN"s) will not be required.

Load growth in the Cañon City area has led to reliability concerns following loss of the two transmission lines connecting that area to the Pueblo part of the Black Hills' system. Several options were considered, and the preferred solution was determined to be a new 115 kV transmission line from West Station to West Cañon. The new line would provide an additional connection to the area to maintain reliable service following the previously mentioned outage. The new connection also enables the future replacement of stressed transmission lines at a greatly reduced

operational risk. Moreover, the project provides the added benefit of adding a 115/69 kV source near the existing North Cañon 69 kV substation. This will offload the existing Cañon City transformer and add operational flexibility to the local 69 kV system. The new source may provide future improved backup service to the Cripple Creek area via the normal open 69 kV line for emergency situations. The initial scope of the West Station-West Cañon project was coordinated with other entities to explore opportunities for joint participation in the project. This was done to potentially meet a wider range of system needs while minimizing the impact to the local landscape through the potential use of double circuit towers and utilization of existing transmission corridors when possible. The project was identified as an SB07-100 project in the 2015 study because it facilitates a larger resource injection from Energy Resource Zone ("ERZ") 4. Refer to the Black Hills Corporation 2015 SB07-100 Study Report included in Appendix L for more information.

As load continues to grow throughout the planning horizon, the need for additional infrastructure will be reviewed as part of a long-term strategy for the Cañon City area.

Pueblo area

The central part of the Black Hills transmission system is in and around the city of Pueblo, Colorado.

Table 3. Pueblo area projects included in the Black Hills 2018 10-Year Plan

Project Name	Est. In-Service Date	Cost (millions)	CPCN
West Station 115 kV Substation Upgrades	2019	$6.5	Not Required

Located between significant generation resources at Comanche and the Denver-Metro area load center, power in this part of the Black Hills system generally flows from south to north. This directional bias, as well as load growth in the area, has resulted in maximum utilization of many of the individual transmission line segments

terminating in the West Station 115 kV substation. A new terminal was needed at West Station to accommodate the planned West Station-West Cañon 115 kV line. Additionally, aging and outdated equipment is preventing some of the transmission lines from realizing the desired thermal rating. Breaker-fail protection is a needed addition to the substation as well. For those reasons, the legacy portion of the West Station substation will be rebuilt and upgraded to address the growth and reliability needs of this important transmission hub on the Black Hills system.

One recently-completed project addressed issues related to the aforementioned south-to-north transfers from the West Station 115 kV substation north toward the Western Area Power Administration ("WAPA") owned Midway substation. The line connecting these substations may experience power flows in excess of its thermal limit under future system conditions. The West Station-Desert Cove 115 kV line rebuild replaced the conductor on the first segment of this line with larger conductor in 2015. The Desert Cove-Fountain Valley-Midway segment of the same line remains under evaluation as a conceptual project to replace the remaining limiting equipment in the future. Together these rebuilt lines, along with other minor terminal equipment upgrades will provide a higher rating to accommodate larger power transfers to areas of need.

Rocky Ford area

Rocky Ford is located between Boone and La Junta and is home to two projects in the 2018 Plan.

Table 4. Rocky Ford area projects included in the Black Hills 2018 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
La Junta 115 kV Area Upgrades	Q4 2019	$3.9	Not Required
Boone-La Junta 115 kV Rebuild	Q4 2020	$20.9	Not Required

The La Junta Area Upgrades project consists of the addition of a second 115/69 kV transformer at La Junta (Black Hills-owned). The project will also add a 69 kV capacitor at Rocky Ford and address local terminal equipment limitations, adding reliability to the La Junta area.

The Boone-La Junta 115 kV line rebuild is a multi-year project beginning in 2018 and ending in 2020. The entire 45-mile length of the line will be rebuilt using larger conductor to address age-related integrity issues as well as provide additional capacity on the only transmission line serving that portion of the Black Hills system. The modest load growth forecasted for the area did not necessitate the need to implement the project at a higher operating voltage.

In addition to the planned projects described in this 10-Year plan, there are other factors that may drive the need for additional transmission facilities. Black Hills issued a request for proposal on June 23, 2017, in Phase II of the 2016 Electric Resource Plan ("ERP") for up to 60 megawatts of eligible energy resources. Black Hills is conducting a competitive bid process to acquire eligible energy resources that will save customers money and provide renewable energy credits to meet Colorado's Renewable Energy Standard. It is uncertain at the time of this filing if the competitive bid process will result in the need for additional transmission infrastructure to accommodate any new generation resources.

Information concerning the specific Colorado projects included in the Black Hills 2018 10-Year Plan is contained in Appendix D. Additional general information can be found at www.blackhillsenergy.com/your-neighborhood/transmission-distribution/transmission-planning/colorado-electric-rule-3627.

B. Tri-State 10-Year Plan Overview

1. Tri-State Planning Process

Tri-State's transmission planning process is intended to facilitate the timely and coordinated development of transmission infrastructure that maintains system

reliability and meets customer needs, while continuing to provide reliable, cost-based electric power to its 43 Member Systems. With Member Systems in four states (Colorado, Nebraska, New Mexico, and Wyoming), Tri-State is a regional power provider with only a portion of its planned transmission facilities located in Colorado and therefore included in this plan.

The primary objectives of Tri-State's transmission planning process are to meet the needs of network and point-to-point customers, maintain reliability, accommodate load growth, and coordinate interconnections. The key elements of Tri-State's transmission planning process are:

- Maintaining safe, reliable electric service to its members at the lowest possible cost;
- Improving efficiency of electric system operations;
- Providing open and non-discriminatory access to its transmission facilities; and
- Planning new transmission infrastructure in a coordinated, open, transparent and participatory manner.

Tri-State's primary planning activities center on the preparation of the 10-Year Capital Construction Plan for approval by the Tri-State Board. All projects included in Tri-State's 10-Year Capital Construction Plan adhere to NERC and WECC Standards and Criteria, FERC Order No. 890 Planning Principles, and coordinated regional planning principles, as well as the criteria outlined in Rule 3627.

Tri-State implements its transmission planning process through various studies, including:

- Reliability studies (for both bulk system infrastructure and sub-transmission);
- System impact studies;
- Transmission service requests;
- Generator interconnection studies;

- Facilities studies; and
- Economic studies.

Tri-State's Member Systems create long-range plans and other work plans that they provide periodically to Tri-State's Transmission Planning Department. When Member Systems' plans indicate the need for system upgrades or new construction, Member Systems apply to Tri-State Transmission Planning for a new or modified delivery point to be served from the Tri-State transmission system. The application contains sufficient information for Tri-State Transmission Planning to identify and consider alternatives to meet the Member Systems' requirements in a manner consistent with immediate and long-term needs in the context of the overall transmission system development.

Tri-State's contribution to the 2018 Plan was developed through an open, transparent, and participatory process that considered the needs and requirements of a wide range of stakeholders and regulatory bodies, including: Tri-State's Member Systems; transmission service customers; national and regional reliability organizations; and other transmission providers in Colorado and the region. Tri-State solicited input from a broad and diverse community of stakeholders including Member Systems, independent power producers, independent transmission companies, renewable energy advocates, environmental advocates, and federal, state, and local government agencies in the areas potentially affected by the proposed transmission projects.

The result of this coordinated and comprehensive process is a 10-Year transmission plan that includes transmission, distribution, and substation projects. Project summary information found in the following section and Appendix E focuses on the projects that involve the construction of new transmission lines in the State of Colorado. These transmission projects consist of some projects that are primarily intended to fulfill a load-serving need, some that are primarily intended to serve an identified reliability need, and some projects that are intended to provide transmission system congestion relief to better accommodate existing and future

generation resources. In addition to these primary purposes, each project is a part of the bulk electric system in Colorado and therefore provides some additional benefits to the overall Colorado electric transmission system.

To understand the context and basis of Tri-State's 2018 Plan, it is important to recognize the key differences between Tri-State and other Colorado utilities. Tri-State is a generation and transmission cooperative formed and owned by its 43 member distribution cooperatives and public power systems located in four states: Colorado, Nebraska, New Mexico, and Wyoming. The territories served by Tri-State's Member Systems cover a total of approximately 200,000 square miles. This large service area results in a load density that is significantly lower than that served by urban utilities. As a cost-based cooperative, Tri-State does not operate for profit and its Board of Directors, elected by the 43 Members, sets the rates charged to Tri-State's Member Systems accordingly. Tri-State's primary mission is to provide its Member Systems cost-based, reliable wholesale electric power. Tri-State does not engage in speculative investments or other activities that are not consistent with its mission.

2. Tri-State Projects

While Tri-State's overall 2018 Transmission Plan includes transmission, substation, and distribution projects throughout Wyoming, Nebraska, Colorado, and New Mexico, this summary focuses on the larger transmission projects in Colorado. Many of these projects provide multiple benefits in terms of load serving, reliability improvements, congestion relief, or the accommodation of new generation. It should be noted that the 2018 Plan includes some projects listed in the 2016 Plan.

Table 5. Load serving projects included in the Tri-State 2018 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Burlington-Lamar 230 kV	2021	$54	Issued
Lost Canyon-Main Switch 115 kV	2022	$17.8	NR

Southwest Weld Expansion Project	2022	$70	Issued
Weld-Rosedale–Milton 230 kV**	TBD	TBD	Req'd

This is a conceptual project

Burlington-Lamar

Past studies in the Boone-Lamar area of Colorado have shown voltage collapse for the Boone-Lamar 230 kV line outage with cross-trips of all generation injected at Lamar 230 kV. In order to mitigate these violations and provide for future growth and potential new generation, Tri-State determined the best solution was to construct a new 230 kV transmission line from the existing Burlington substation to the existing Lamar substation.

Lost Canyon Main Switch

There is heavy load growth in the CO2 Loop consisting of the Yellow Jacket Switch-Main Switch-Sand Canyon-Hovenweep-Yellow Jacket 115 kV system. Constructing the new Lost Canyon-Main Switch 115 kV line will provide support to reliably meet the future load growth for the CO2 Loop in southwestern Colorado.

Southwest Weld Expansion Project

Due to large scale oil and gas development in Southwest Weld County and native load growth, Tri-State is planning on constructing approximately 49 aggregate miles of 115 kV and 230 kV transmission lines to meet the forecasted demand of approximately 300 Megawatts ("MW") within the next five years. Six potential 115 kV load-serving substations and/or line taps may be constructed by Tri-State, while new 69 kV transmission lines and substations will be constructed by United Power for the project.

Weld-Rosedale-Milton 230 kV

See description in Section III.C.2, Public Service Conceptual Plans.

Table 6. Reliability projects included in the Tri-State 2018 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Sunshine-Telluride Line Upgrade	2019	$3.1	NR
Western Colorado Transmission Upgrade Project	2019	$120	Issued
Burlington-Burlington (KCEA) Rebuild	2020	$2.3	NR
Burlington-Lamar 230 kV	2021	$54	Issued
Falcon-Midway 115 kV Line Uprate	2021	$5.6	NR
Falcon-Paddock-Calhan 115 kV Line	2022	$33.4	NR
Lost Canyon-Main Switch	2022	$17.8	NR
San Luis Valley-Poncha 230kV #2	2022	$58	Req'd
Southwest Weld Expansion Project	2022	$70	Issued
Lamar Front Range	TBD	$900	Req'd
Weld-Rosedale-Milton 230 kV**	TBD	TBD	Req'd

*****This is a conceptual project***

Sunshine-Telluride Line Uprate

Tri-State has identified the need for additional space at Sunshine substation to allow connection of a 115/69 kV mobile transformer in emergency conditions, as well as connection of a new 16 MVAR reactor to supplement and backup the existing Norwood reactor used to mitigate high voltages in the area. To create additional space, the existing Sunshine-Telluride 69 kV line will be re-energized at 115 kV and

the Sunshine 115/69 kV transformer will be removed. Energizing the Sunshine – Telluride line at 115 kV will also improve load serving capability at Telluride.

Western Colorado Transmission Upgrade Project

The 40-mile long Montrose-Nucla and Nucla-Cahone 115 kV transmission lines are old, overloaded, undersized, and must be rebuilt. To ensure continued reliability of the southwest Colorado transmission system, Tri-State is replacing them with new, higher capacity lines rated for 230 kV operation. This project will increase the load serving capability of the southwest Colorado transmission system and also eliminate the need for the existing Nucla Remedial Action Scheme, which trips the Montrose-Nucla line when it starts to overload after contingencies/outages in the area.

Burlington-Burlington (KCEA) Rebuild

Under peak loading conditions, the K.C. Electric Association ("KCEA") 69 kV system fed from Smoky Hill substation cannot be switched to the west to pick up additional load for the loss of the Limon source after the Smoky Hill transformer is replaced with a larger unit. To mitigate this limitation, Tri-State will rebuild the Burlington-Burlington KCEA line with 795 kcmil ACSR "Drake" conductor. The increased capacity will also help K.C. Electric Association serve new load in the area.

Burlington-Lamar

See description in Section III.B.2, Load Serving.

Falcon-Midway Line Uprate

The current Falcon-Midway 115 kV transmission line has a thermal rating of 95 MVA, which leads to forecasted overloads by the summer of 2018 from an outage on Tri-State's 115 kV Falcon-Fuller line. In order to mitigate this problem, Tri-State is raising, moving, or rebuilding structures along the line to increase the overall line rating to 140 MVA. The increased capacity will help serve Mountain View Electric Association's ("MVEA") customer load in the area. The project is being built and financed solely by Tri-State.

Falcon-Paddock-Calhan 115 kV Line

The current Falcon-Paddock-Calhan 69 kV transmission line will be rebuilt to create a 115 kV loop in MVEA's central system. The 115 kV line will improve system reliability by looping the existing radial 115 kV and 69 kV substations in MVEA's system and provide increased voltage support. The 115 kV line will also help serve MVEA's customer load growth in the area. The project is being built and financed solely by Tri-State.

Lost Canyon Main Switch

See description in Section III.B.2, Load Serving.

San Luis Valley-Poncha 230 kV #2

New high-voltage transmission must be built in the San Luis Valley ("SLV") region of south-central Colorado to maintain electric system reliability and customer load-serving capability, and to accommodate development of potential generation resources. Tri-State and Public Service , working through CCPG, facilitated a study of the transmission system immediately in and around the SLV and developed system alternatives that would improve the transmission system between the SLV and Poncha Springs, Colorado. Both Tri-State and Public Service have electric customer loads in the SLV region that are served radially from transmission that originates at or near Poncha. The study concluded that, at a minimum, an additional 230 kV line is needed to increase system reliability. Studies show that this could be accomplished by either adding a new 230 kV line or rebuilding an existing lower voltage line and operating it at 230 kV.

Southwest Weld Expansion Project

See description in Section III.B.2, Load Serving.

Lamar Front Range

The Lamar Front Range Project was developed jointly through the CCPG to significantly improve load-serving capability, reliability, and potential resource accommodation in eastern and southeastern Colorado. The project could provide

connectivity to the bulk transmission systems of Tri-State and PSCo, and provide strong “looped service” to areas with long radial transmission configurations. In concept, the project could create a transmission system capable of at least 2000 MW of new generation in eastern and southeastern Colorado.

This conceptual project identifies the transmission element additions that are needed to meet both companies’ needs, including delivery of future generation to loads in the Denver and Front Range areas. The conceptual Lamar Front Range project envisions 345 kV transmission lines connecting Lamar to the Pueblo area, Lamar to the Burlington and Big Sandy area, and Big Sandy to the Missile Site, Story and Pawnee areas. As the actual transmission needs in the Lamar Front Range Project area have been smaller, several projects are being implemented at a smaller scale, but in a manner consistent with the outline of the Lamar Front Range Project. An example of this is the Burlington-Lamar Project.

Weld-Rosedale-Milton 230 kV

See description in Section III.C.2, Public Service Conceptual Plans.

Table 7. Generation Congestion projects in the Tri-State 2018 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Burlington-Lamar 230 kV	2021	$54	Issued
Lamar Front Range	TBD	$900	Req’d
Lamar-Vilas 230 kV	TBD	$90	Req’d

Burlington-Lamar

See description in Section III.B.2, Load Serving.

Lamar Front Range

See description in Section III.B.2, Reliability.

Lamar-Vilas 230 kV Transmission

See description in Section III.C.2, Public Service Conceptual Plans.

Information concerning the specific Colorado projects included in the Tri-State 2018 10-Year plan is contained in Appendix E. Additional information and supporting documentation can be found at Tri-State's website.

C. Public Service 10-Year Plan Overview

Public Service is one of four electric utility operating companies of Xcel Energy Inc., which is an investor-owned utility serving approximately 1.4 million electric customers in the State of Colorado. Public Service serves approximately 75 percent of the State's population. Its electric system is summer-peaking with a 2016 peak customer demand of 6665 MW. The entire Public Service transmission network is located within the State of Colorado and consists of over 4500 miles of transmission lines. Colorado is on the eastern edge of the WECC transmission system, which constitutes the Western Interconnection. The Western Interconnection operates asynchronously from the Eastern Interconnection. The Public Service transmission system is interconnected with the transmission system of its affiliate, Southwestern Public Service Company, via a jointly-owned tie line with a 210 MW High Voltage Direct Current ("HVDC") back-to-back converter station. Most of the Public Service retail service customers are located in the Denver-Boulder metro area. However, the Public Service retail service territory also includes the I-70 corridor to Grand Junction, the San Luis Valley region, and the cities and towns of Greeley, Sterling, and Brush.

1. Public Service Planning Process

The goal of coordinated planning, as described in Commission Rule 3627 and historically practiced by Public Service and other TPs, is to develop the best possible transmission plan to meet their present and future demands for electricity, taking into account a number of diverse factors. At its most basic level, transmission planning strives to meet customers' energy needs in a reliable and cost-effective manner.

The Public Service transmission planning process is intended to achieve the following objectives:

- Maintain reliable electric service;
- Improve the efficiency of electric system operations, including the provision of open and non-discriminatory access to our transmission facilities pursuant to FERC requirements;
- Identify and promote new investments in transmission infrastructure in a coordinated, open, transparent, and participatory manner; and
- Involve stakeholders during the transmission planning process and review alternatives.

The planning process is coordinated with all the other transmission providers in the state to avoid duplication and reduce costs to the end use customer.

As described in earlier sections, coordinated transmission planning in the State of Colorado depends on careful consideration of numerous factors and variables, as well as thoughtful consideration of input from organizations and individuals on the regional, sub-regional, and local level.

2. Public Service Projects

Table 8, below, lists the Public Service projects over 100 kV.

Table 8. Public Service 10-Year Plan

Project Name	ISD	Sub	Trans	Upgrade	Cost	Purpose
Completed						
Wolcott 230 kV Substation Reactors	2016	X		X	$6.2	R
Cherokee-Ridge 230 kV Transmission	2016		X	X	$4.7	R
Rifle-Parachute 230 kV line	2016		X		$28.5	R
Happy Canyon Substation	2016	X			$3.0	L
New to 2018 Filing						
Rush Creek-Missile Site 345 kV Transmission	2018	X	X		$121.4	G
Two Basins Relocation	2018		X	X	$29.1	R

Bluestone Valley Substation Phase 1	2018	X			$7.2	R
NREL Substation	2019	X			$6.7	G
Monument-Flying Horse 115 kV Phase Shifter	2020	X		X	TBD	R
Badger Hills Substation	2020	X			$26.6	G
Previously Listed Planned						
Moon Gulch 230 kV Substation	2018	X			$1.9	L
Pawnee-Daniels Park 345 kV Transmission	2019	X	X		$178.3	R,G
Avery Substation	2019	X			$10.3	L
Thornton Substation	2019	X			$24.7	L
Ault-Cloverly 230/115 kV Transmission	2020	X	X		$65.0	R,L
Avon-Gilman 115 kV Transmission	2022		X		$22.9	R
Conceptual						
Weld-Rosedale-Milton 230 kV	TBD		X		TBD	R,L
Weld County Expansion Transmission	TBD		X		TBD	R,G
Bluestone Valley Substation Phase 2	TBD	X			TBD	L
Glenwood-Rifle 115 kV Transmission	TBD		X		TBD	R,L
Hayden-Foidel-Gore 230 kV	TBD		X		TBD	R
Lamar-Front Range Transmission	TBD		X		$900	R,G
Lamar-Vilas 230 kV Transmission	TBD		X		$90	G
Parachute-Cameo 230 kV #2 Transmission	TBD		X		$48	R,L
Rifle-Story Gulch 230 kV Transmission	TBD		X		$24	L
Wheeler-Wolf Ranch 230 kV Transmission	TBD		X		$17	L
San Luis Valley[3]	TBD	X			TBD	R,G
Distribution Driven Subs						
Barker Distribution Substation	2022	X			$18	L
Wilson Substation	TBD	X			$4	L
Titan Distribution Substation	2022	X			TBD	L
Dove Valley Distribution Substation	2022	X			TBD	L
High Point Distribution Substation	2022	X			TBD	L
Stock Show Distribution Substation	2022	X			TBD	L
New Castle Distribution Substation	TBD	X			$1.4	L
Solterra Distribution Substation	TBD	X			TBD	L
Superior Distribution Substation	TBD	X			TBD	L
Sandy Creek Distribution Substation	TBD	X			TBD	L

[3] Tri-State lists as “planned” with 2022 ISD.

Key: R – Reliability, L – Load-serving, G – Generation

Public Service's planned transmission projects can generally be placed in two basic categories. The first category consists of projects that are needed primarily for load growth or reliability purposes. These include both new projects as well as rebuilds or upgrades to existing transmission lines. Native load peak demand in Public Service's service territory has remained fairly flat during the past five years. The expiration of wholesale contracts and the participation of wholesale customers in the Comanche 3 power plant have contributed to this weak load growth. Since 2009, the Public Service firm wholesale load has decreased, but the loss of wholesale load was offset by load growth within the retail sector. The slower load growth is also due to increases in energy efficiency and demand-side management programs, changes in appliance efficiency, reductions in wholesale load now served by generation facilities installed in the region, and the increase in use of on-site photovoltaic energy systems. Public Service presently forecasts the load to grow by about 1.6% through 2023. While transmission planners consider the potential for demands to return to historical rates, the general trend in this planning horizon is that project scopes are likely to contract and the timing for some projects may be delayed.

The second category consists of projects that are planned primarily to accommodate new generation resources. For Public Service, these projects tend to be associated with Senate Bill 07-100 and the Company's ERPs. These projects include large transmission projects to access specific areas of the state that have the potential to host future wind, solar, and fossil generation facilities. The Company takes into consideration recent forecasts that indicate slower load growth and also where it stands with meeting its Renewable Energy Standard ("RES") requirements when approaching transmission planning. As a result, while the Company has developed plans to access each ERZ in Colorado, some projects do not have specific in-service dates. However, plans may continue to evolve incorporating consideration of other utilities' plans, Public Service load and resource needs, and the relative cost of new renewable resources and fossil generation. SB07-100 continues to be a driver for the development of transmission plans that could deliver energy from beneficial resources.

Public Service's transmission plan does not currently include multi-state, region-wide transmission projects. However, Public Service watches for such opportunities. While some of the components of the current transmission plan could be used as components of a regional transmission project, Public Service has not identified regional project opportunities at this time to include in this plan.

Following is a brief, narrative description of each Public Service project included in Table 1 and how it fits into the overall 2018 Plan. Information for the auxiliary projects shown in Table 8, as well as maps of the Public Service projects for each of the time-frames listed below can be found in Appendix F. Projects are arranged by their anticipated in-service dates.

Projects Implemented Since 2016

This section describes the Public Service projects that have been placed in-service since the 2016 Rule 3627 10-Year Transmission Plan ("2016 Filing"). The following project(s) consisted of upgrades or additions to existing substations. These are not shown on the transmission system maps.

Wolcott 230 kV Substation Reactors

The 2016 Filing listed the Hayden-Foidel Creek-Gore Pass 230 kV Transmission Project as a conceptual plan to increase reliability and improve voltage performance in the region, and that voltage issues would be mitigated by installing voltage control devices in the region. Two 20 MVAR reactors were added in 2016 at the Wolcott Substation for that purpose. The Hayden-Foidel Creek-Gore Pass project continues to be a conceptual plan that could improve reliability when needed in the future. The project was implemented in 2016. The cost of the reactors was approximately $6.2 million.

Cherokee-Ridge 230 kV Transmission

This project was included in the 2016 Filing and consisted of converting the existing Cherokee-Arvada-Russell-Ridge 115 kV line to 230 kV operation for increased reliability. The project was completed in 2016 at a cost of $4.7 million.

Rifle-Parachute 230kV Transmission Line #2

This project was included in the 2016 Filing as a means to improve reliability and accommodate load growth on the Western Slope of Colorado. The project was placed in-service in 2016 at an approximate cost of $28.5 million.

Happy Canyon Substation

This project was included in the 2016 Filing and consists of constructing a new Happy Canyon 115 kV substation tapping the existing Daniels Park-Castle Rock 115 kV line to allow Intermountain Rural Electric Association ("IREA") a delivery point for their customers in the area. The project was completed in 2016 at an approximate cost of $3 million.

New Transmission and Substation Projects

This section describes the Public Service projects that have not been included in previous Rule 3627 filings.

Rush Creek-Missile Site 345 kV Transmission

In May of 2016, Public Service filed a proposal with the CPUC to build, own and operate the Rush Creek Wind Project in eastern Colorado. The project includes 600 MW of new wind power and a corresponding approximately 83-mile 345 kV transmission line to be built in parts of Arapahoe, Cheyenne, Elbert, Kit Carson, and Lincoln counties. Since the transmission line is a radial line that accommodates new generation, it is sometimes referred to as a "gen-tie". The filing consisted of an application for a CPCN. In September 2016, the CPUC approved a Settlement Agreement between the Company and several interveners and also approved the CPCN.

Construction started on the Rush Creek Gen-tie ("Gen-tie") in August 2017 and has a planned in-service date of October 2018. The project will include two collector stations. One collector will be a new Pronghorn Substation, located approximately 45 miles from Missile Site Substation. The second collector will be at the eastern end of the Gen-tie (38 miles from Pronghorn).

As part of the Settlement Agreement for the Rush Creek Wind Project proceedings, Public Service took a leadership role in the Rush Creek Task Force created within the CCPG. The Task Force analyzed the costs and benefits of nineteen alternative proposals to potentially integrate the Rush Creek 345 kV Gen-tie as a network facility. The process provided a forum for stakeholder participation and comment. A final report was completed and accepted by CCPG on September 15, 2017 and is posted on the CCPG web site, in the Rush Creek Task Force section http://regplanning.westconnect.com/ccpg.htm. *The Stakeholder Process for Rush Creek is described in Section VI.D. and included in Appendix K.* The project is planned to be in-service in 2018 at an approximate cost of $121.4 million.

Two Basins Relocation Project

This project consists of relocating three existing 115 kV transmission lines that connect to the North Substation. The project is necessary to accommodate the City and County of Denver ("CCOD") Two Basins Storm Water Drainage Project which will provide 100-year storm protection for certain areas of the city. The project is also required to accommodate the Colorado Department of Transportation ("CDOT") I-70 Expansion Project. The project involves: 1) Re-locating a portion of the existing North-Capitol Hill 115 kV underground line. 2) Re-locating the entire existing North-California 2.25-mile 115 kV underground line and replacing it with new conductor, and 3) Re-locating and replacing four overhead structures on the existing North-Sandown 115 kV line. The CPUC determined that the project was in the ordinary course of business and did not require a CPCN. The project has a planned in-service date of 2018 and an estimated cost of $29.1 million.

Bluestone Valley Substation (Phase 1)

The 2016 Filing listed Bluestone Valley Substation as a conceptual project to improve reliability and provide additional load interconnections for customers in the area. The original scope of this project consisted of a new Bluestone Valley 230/69 kV Substation. The substation would include a 230/69 kV transformer and would interconnect the existing Parachute-Cameo 230 kV line and the existing DeBeque-Cameo 69 kV line. From Bluestone Valley Substation, a new line would be constructed to a new Grand Valley Power Clear Creek Substation. Public Service has now split this project into two phases: A 69 kV phase ("Phase 1") and a 230 kV phase ("Phase 2"). To expedite reliability improvements to the lower voltage network, Public Service plans to move forward with Phase 1. Phase 2 is still considered conceptual and may be constructed at a later time based on local load growth. Phase 1 includes construction of a new Bluestone Valley 69 kV Switching Station that will connect to the existing DeBeque-Cameo 69 kV line. The project will result in a DeBeque-Bluestone Valley-Cameo 69 kV line. The project has a planned in-service date of June 2018, with an estimated cost of $7.2 million.

NREL Substation

This project consists of a new substation which taps the existing Plainview-Eldorado 115 kV line south of Boulder, Colorado. The U.S. Department of Energy's National Renewable Energy Laboratory ("NREL") operates a hybrid generation facility at its National Wind Technology Center, located approximately 1 mile east of the line. This facility is currently interconnected via distribution service, so the generation capacity is limited. This project is needed to interconnect the generation to the transmission system and allow for additional generation interconnections. The project has a planned in-service date of 2019, with an estimated cost of $6.7 million.

Monument-Flying Horse 115 kV Phase Shifting Transformer

This project consists of adding a phase shifting transformer ("PST") at the Monument Substation on the Monument-Flying Horse 115 kV transmission line, to control power flows through the Colorado Springs Utilities ("CSU") transmission system. The CSU

system consists of 115 kV and 230 kV lines that are electrically in parallel to the 230 kV and 345 kV transmission lines that Public Service uses to deliver power to Denver from its generation resources in the south. Studies have shown that when there are heavy power transfers on the transmission system between Pueblo and the Denver, there is a potential for unacceptable loading to occur on the CSU transmission system. As a temporary mitigation measure, Public Service has implemented an operating procedure that opens up a 115 kV line on the north end of the system where the CSU and Public Service systems connect. Public Service has been working with CSU to determine a long term transmission solution to mitigate the potential overloads. As of this filing, studies indicate that a PST could eliminate the operating procedure and provide more reliability to the CSU system. However, studies are preliminary and may result in an alternative solution. A cost estimate for this project has not been developed, but Public Service believes such a project could be implemented by 2020. Public Service will provide updates to the status of this project through CPUC Rule 3206 filings and other Public Service stakeholder presentations.

Badger Hills Substation

This project consists of adding a new substation in Pueblo County to accommodate additional generation resources in the area. Since there are some physical constraints to interconnecting new generation resources at the Comanche Substation, Public Service is proposing the new Badger Hills Substation. It will likely be located approximately 12 miles southeast of Comanche Substation. The plan is to interconnect at least one 230 kV line and one 345 kV line between Comanche and Midway / Daniels Park, and include a 345/230 kV transformer. The project has a planned in-service date of 2020, with an estimated cost of $26.6 million.

Planned Transmission Projects (Listed in Previous Filings)

Moon Gulch Substation

Moon Gulch Substation is a new distribution substation to be built in the City of Arvada within Jefferson County. The substation will tap the Plains End-Simms 230 kV line. It is needed to serve load growth in the Arvada area and will also provide backup service to

the existing Eldorado and Ralston distribution substations. The project was listed in the 2016 Filing as having an in-service date of 2019, but now has a planned in-service date of 2018, with an estimated cost of $1.9 million.

Pawnee-Daniels Park Transmission

The Pawnee-Daniels Park 345 kV Transmission Project has been described in previous Rule 3627 filings with an in-service date of 2022. The project consists of building a 125-mile 345 kV transmission line from the Pawnee Substation in northeastern Colorado to the Daniels Park Substation, south of the Denver-Metro area. The project will also result in constructing a new Harvest Mile 345 kV Substation, near Smoky Hill Substation, and a new Harvest Mile-Daniels Park 345 kV line. The project will also interconnect with the Missile Site 345 kV Substation. This project was planned in accordance with Senate Bill 07-100 in that it will accommodate generation in designated ERZs 1 and 2. Public Service received a first CPCN ruling for the project in March 2015. Public Service requested an in-service date of 2019. However, the CPUC ruled that the project could not start construction before 2020. That corresponded to an in-service date of 2022. During the Rush Creek Wind Project proceedings in 2016, Public Service requested that the CPUC approve an expedited schedule for the Pawnee-Daniels Park 345 kV Transmission Project to support the Rush Creek Wind Project. The CPUC approved both the Rush Creek Wind Project and Gen-tie, and the request to expedite the Pawnee-Daniels Park Project. With that ruling, the Pawnee-Daniels Park Project is now scheduled to be placed in-service in October 2019, with an estimated cost of $178.3 million.

Avery Substation

This project consists of constructing a new Avery distribution substation, which will be located in Weld County. The transmission source for Avery will be the Platte River Power Authority (“PRPA”) Ault-Timberline 230 kV line. It is needed to serve the increase in customer distribution load in that area. The project was listed in the 2016 Filing as having an in-service date of 2017, but now has a planned in-service date of 2019, with an estimated cost of $10.3 million.

Thornton Substation

This project consists of constructing a new substation in Thornton that will be used to serve the increase in customer distribution load in that area. This new substation will serve the City of Thornton in the north metro Denver area and provide back-up support to the existing Glenn and Washington distribution substations. The project has a planned in-service date of 2019, with an estimated total cost of $24.7 million.

Ault-Cloverly 230/115 kV Transmission Project

This project was referred to in the 2016 Filing under the Greeley Area Transmission as the Northern Greeley, or Ault-Monfort Transmission Project for Public Service. The Ault-Cloverly Project consists of approximately 25 miles of new 230 kV and 115 kV transmission lines originating at the existing WAPA Ault Substation near the town of Ault, and terminating at the Public Service Cloverly Substation on the northeast edge of Greeley. The transmission will also interconnect with two new PSCo substations: Husky Substation, which will replace and is planned to be built near the existing PSCo Ault 44 kV Substation, and Graham Creek Substation, which will replace and is planned to be built near the existing PSCo Eaton 44 kV Substation. The primary purpose of the project is to improve reliability by replacing the existing 44 kV system in the area with higher voltage transmission facilities. The project is also necessary to increase the load-serving and generation resource capability in the area. Public Service filed for a CPCN on March 9, 2017 and is awaiting a decision.

The project was listed in the 2016 Filing as having an in-service date of 2019, but now has a planned in-service date of 2020 with an estimated cost of $65.0 million.

Southwest Weld Expansion Project (not in Table 8)

Public Service referenced this Tri-State project in the 2016 Filing under the Greeley Area Transmission section. The project is described by Tri-State in Section III.B.2. The Southwest Weld Expansion Project (“SWEP”) passes near or through Public Service

customer service territory, and could provide opportunities to link with other transmission plans in northeast Colorado. As a result, Public Service is continuing to evaluate the potential for participation in SWEP.

Avon-Gilman 115 kV Transmission Project

The Avon-Gilman 115 kV Transmission Project consists of constructing a new 10-mile 115 kV line in Eagle County for reliability and to provide an alternate transmission source to Holy Cross Energy customers. The project was listed in the 2016 Filing as having an in-service date of 2019, but now has a planned in-service date of 2022, with an estimated cost of $22.9 million.

Conceptual Plans

The following transmission plans are considered conceptual in that they have no specific in-service date. Implementation of these plans is primarily affected by load forecasts and electric resource needs. Once a need is established, in-service dates can depend on many factors, including regulatory proceedings, siting and land permitting, coordination of construction outages, and material delivery times. Public Service continues to assess the system conditions that may drive implementation for these plans.

Weld-Rosedale-Milton 230 kV Transmission Lines

Following the Ault-Cloverly Project approval, Public Service has been working through the CCPG Northeast Colorado (“NECO”) Subcommittee to develop a transmission plan for the area south of Greeley. The objective is to continue the replacement of the existing 44 kV system in the area, increase the ability to accommodate future load growth, allow for beneficial resource development, and align with other transmission projects and plans in the area, including the Ault-Cloverly Project and the SWEP. The Weld-Rosedale and Rosedale-Milton 230 kV transmission projects have been listed in Rule 3206 filings and other Public Service presentations as potential projects to meet

the objectives. The two projects could consist of approximately 26 miles of new 230 kV transmission originating at the Tri-State Milton Substation (the northern 230 kV terminus of SWEP), tie into the Public Service Rosedale Substation, south of Greeley, and terminate at the Weld Substation, east of Greeley. The 2016 Filing listed the projects as having 2022 in-service dates. The Weld-Rosedale-Milton projects have been listed in other filings as having in-service date of 2022. However, until the NECO studies are completed and an actual project is recommended, these projects are listed as conceptual with no specified in-service date or estimated costs.

Weld County Transmission Expansion

This plan was described in the 2016 Filing as a means to allow interconnection of new resources and complement other transmission plans in Northeast Colorado. The Weld County Expansion continues to be more of a general planning placeholder that captures the planning efforts for Northeast Colorado, including the Greeley area. The planning has been taking place in the CCPG NECO Subcommittee. As specific plans are developed, such as the Ault-Cloverly Project, they will be described in Public Service filings and stakeholder forums.

Bluestone Valley Substation (Phase 2)

As mentioned previously, this project has been divided into two phases. Phase 2 of the project would consist of expanding the substation to include 230 kV facilities, which would include a 230/69 kV transformer and interconnect the Rifle-Cameo 230 kV line. Implementation of Phase 2 will depend on the local load growth.

Glenwood-Rifle Transmission

This plan was described in the 2016 Filing, and consists of upgrading the Glenwood Springs-Mitchell Creek-New Castle-Silt Tap line from 69 kV to 115 kV and new construction to reroute the Silt-Rifle line to the Rifle Substation at 115 kV. A portion of the rerouted 115 kV line will be double-circuited with the Rifle-Hopkins 230 kV line.

Costs for the plan have not been estimated, and moving forward with the plan will depend on load growth around Glenwood Springs.

Hayden-Foidel Creek-Gore Pass 230 kV Transmission

This plan was described in the 2016 Filing and would consist of tying the Hayden-Gore Pass 230 kV line into the Foidel Creek Substation to increase reliability in the region. Reliability concerns are being mitigated by adding reactors at the Wolcott 230 kV bus, so there are no plans to move forward with this project at this time.

Lamar-Front Range and Lamar-Vilas Transmission

The Lamar-Front Range plan has been described in numerous filings and presentations as a means to deliver an estimated 2000 MW of new generation from energy resources near Lamar and Burlington to load centers along the Front Range. The plan was conceived as a joint project between Public Service and Tri-State. A primary driver for Public Service was to meet an SB07-100 objective to plan transmission from the ERZ-3. The overall plan includes the following transmission components:

- Two 345 kV transmission circuits between Lamar and Avondale
- Two 345 kV transmission circuits between Lamar and Burlington
- Two 345 kV transmission circuits between Burlington and Big Sandy
- One 345 kV transmission line between Big Sandy and Missile Site
- One 345 kV transmission line between Big Sandy and Story
- One 345 kV transmission line between Story and Pawnee
- A new Avondale Substation
- Two 230 kV transmission circuits between Lamar and Vilas

The Lamar-Front Range project was estimated to cost approximately $900 million. Since the plan was developed, a number of smaller projects that could either be considered segments of, or are consistent with the design of the plan have been implemented or planned. These include the Tri-State Burlington-Lamar Project, the Tri-State Boone-Lamar Project, and the Public Service Rush Creek-Missile Site Project.

Parachute-Cameo 230 kV #2 Transmission

This project was described in the 2016 Filing and other documents as an extension of the Rifle-Parachute 230 kV Transmission Project. It would consist of a new, approximately 30-mile 230 kV transmission line that would connect the existing Parachute and Cameo substations on the Western Slope of Colorado. Its primary purpose would be to increase reliability and to serve load growth in the region. Preliminary analysis estimates the cost to be approximately $48 million, but moving forward with the project will depend on load growth in the area.

Rifle-Story Gulch Transmission

The project was described in the 2016 Filing and consists of a new radial 230 kV transmission line that would be used to serve customer loads in Garfield County. The line would be approximately 25 miles long and run between the existing Rifle (Ute) Substation to a new Story Gulch Substation. The project has an estimated cost of $24 million, but moving forward will depend on load growth in the area.

Wheeler-Wolf Ranch

The project was described in the 2016 Filing and consists of a new radial 230 kV transmission line that would be used to serve customer loads in Garfield County. The line would be approximately 18 miles long and run between the existing Wheeler Substation to a new Wolf Ranch Substation. The line would also interconnect to the Middle Fork Substation. The project has an estimated cost of $17 million, but moving forward will depend on load growth in the area.

San Luis Valley

As stated under the Tri-State 10-Year Plan Overview, Public Service also recognizes the need for new high-voltage transmission in the San Luis Valley to improve electric system reliability and customer load-serving capability, and to accommodate

development of potential generation resources. Public Service co-chairs the San Luis Valley Subcommittee of the CCPG, which has the objective to perform analyses and develop plans to improve the transmission system between the San Luis Valley and Poncha. The first phase of studies verified that, at a minimum, a new 230 kV transmission line from San Luis Valley Substation to Poncha Substation would be a first step to accomplish the objectives. A second phase of studies identified alternatives for transmission beyond Poncha to enhance reliability and generation export potential from the San Luis Valley to the Front Range. (Also see the narrative regarding SLV in the Tri-State section).

San Luis Valley-Poncha 230 kV #2

New high-voltage transmission must be built in the SLV region of south-central Colorado to maintain electric system reliability and customer load-serving capability, and to accommodate development of potential generation resources. Tri-State and Public Service, working through CCPG, facilitated a study of the transmission system immediately in and around the SLV and developed system alternatives that would improve the transmission system between the SLV and Poncha Springs, Colorado. Both Tri-State and Public Service have electric customer loads in the SLV region that are served radially from transmission that originates at or near Poncha. The study concluded that, at a minimum, an additional 230 kV line is needed to increase system reliability. Studies show that this could be accomplished by either adding a new 230 kV line or rebuilding an existing lower voltage line and operating it at 230 kV.

Other Long-Range Distribution Planning Substation Projects

Public Service, the Colorado Office of Consumer Counsel, ("OCC") and Staff of the Colorado Public Utilities Commission agreed in Proceeding No. 14A-1002E to identify potential new distribution substation sites in rapidly growing areas. Below is a list of conceptual new substation projects under consideration by the Company. This is provided for informational purposes only. At this time, Public Service is not seeking Commission determination of the need for CPCNs for these projects or any Commission action. Most in-service dates for these projects are TBD.

Table 9. Long-Range Distribution Planning Substation Projects

Substation Project Name	Transmission Voltage	Approximate location	Potential ISD	Cost ($M)
Barker	230 kV	Across from Coors Field in Denver	2022	$18.1
Dove Valley	115 kV	Near I-25 and C-470 in Arapahoe County	2022	TBD
High Point	115 kV or 230 kV	Near Denver International Airport; Adams County	2022	TBD
Titan	230 kV	Near Sterling Ranch in Douglas County	2022	TBD
Stock Show	115 kV	Denver	2022	TBD
Wilson	115 kV	Loveland	TBD	$3.5
Solterra	230 kV	Lakewood	TBD	TBD
New Castle	69 kV	New Castle	TBD	$1.4
Superior	115 kV	Town of Superior	TBD	TBD
Sandy Creek	230 kV	Arapahoe County, near future Sandy Creek development	TBD	TBD

Additional Information

Information concerning the specific Colorado projects included in the Public Service 2018 10-Year Plan is contained in Appendix F. Additional information and supporting documentation can be found at:

http://www.transmission.xcelenergy.com/Planning/Planning-for-Public-Service-Company-of-Colorado

http://www.rmao.com/wtpp/psco_studies.html

http://www.oatioasis.com/psco/index.html

IV. Projects of Other CCPG Transmission Providers

In addition to the projects planned by Black Hills, Tri-State, and Public Service contained in this 2018 Plan, a thorough understanding of all transmission projects planned in Colorado requires consideration of projects planned by other utilities and TPs.

Table 10. Colorado Springs Utilities Projects

In-Service	Project Name	Description	Purpose
November 2017	Nixon South Second Transmission Line	Extend existing 230 kV Nixon-Kelker south to Front Range Power Plant	Provide a second line to Front Range Power Plant to eliminate the N-1 for loss of the existing line.
June 2018	Kelker 3rd 230/115 kV Autotransformer	Add 230/115kV autotransformer at Kelker.	Increase system load serving capacity and maintain compliance with NERC Standard requirements.
December 2019	Series Reactor-Nixon-Fountain 115kV system	Install a series reactor on the Nixon to Fountain 115kV transmission line.	Mitigate a severe contingency overload and eliminate an existing Operating Procedure.
December 2019	Cottonwood 230/115kV Autotransformer Replacement.	Install a new, upgraded 230/115 kV autotransformer at Cottonwood substation.	Increase system load serving capacity and provide compliance with the Long Lead Time Equipment requirement in the NERC Transmission Planning Standard TPL-001-4. (The existing Cottonwood auto will be refurbished and stored on site as a system spare.)

This information is provided voluntarily by CSU for the purposes of making sure the PUC has the most complete information for planned project coordination purposes only.

Additional information concerning the specific Colorado projects included in the CSU Plan are contained in Appendix G.

Table 11. Platte River Power Authority Projects

In-Service	Project Name	Description	Purpose
May 2018	Boyd 230/115kV Substation Expansion	Add 230/115kV transformer T2 and reconfigure 230kV and 115kV yards to breaker-and-a-half arrangement.	Improve system reliability in the Loveland area.

This information is provided voluntarily by PRPA for the purposes of making sure the PUC has the most complete information for planned project coordination purposes only.

Additional information concerning the specific Colorado project included in the PRPA is contained in Appendix H.

Table 12. Western Area Power Authority Projects

In-Service	Project Name	Description	Purpose
2020	Midway KV1A Replacement	Replacing KV1A at Midway	Replacing aging equipment and increasing size
2020	Ault 345/230 kV XFMR Replacement	Replacing the 345/230 kV Transformer at Ault	Increased reliability

This information is provided voluntarily by WAPA for the purposes of making sure the PUC has the most complete information for planned project coordination purposes only.

Additional information concerning the specific Colorado projects included in the WAPA are contained in Appendix I.

V. Senate Bill 07-100 Compliance and Other Public Policy Considerations

In addition to planning for load growth and reliability, Companies must consider proposed and enacted public policies. Two of the Companies, Black Hills and Public Service, are subject to the requirements of Colorado Senate Bill 07-100 ("SB07-100") (codified at C.R.S. (§) 40-2-126).

Historically, the SB07-100 filings were made by Black Hills and Public Service by October 31 of each odd-numbered year. Those filings were subsequently combined into a single Proceeding with the Rule 3627 filing. In 2017, Decision No. R17-0747 in Proceeding 17R-0489E modified SB07-100 and Rule 3627 to allow Black Hills and Public Service to demonstrate that the requirements of SB07-100 were met as part of the Rule 3627 Ten Year Plan. As stated in SB07-100, Black Hills and Public Service are required to:

a. Designate ERZs
b. Develop plans for the construction or expansion of transmission facilities necessary to deliver electric power consistent with the timing of the development of beneficial energy resources located in or near such zones
c. Consider how transmission can be provided to encourage local ownership of renewable energy facilities
d. Submit proposed plans, designations, and applications for Certificates of Public Convenience and Necessity to the Commission for simultaneous review

Black Hills and Public Service have performed transmission planning activities to comply with the requirements of SB07-100 as part of the larger, coordinated planning efforts described above. As of 2017, Colorado's ERZs remain as they were defined in the 2015 SB07-100 reports, created by consulting multiple sources of information as well as public feedback. As shown in Figure 7, Colorado's five ERZs are:

ERZ 1 (Northeast Colorado)

Includes all or part of Sedgwick, Phillips, Yuma, Washington, Logan, Morgan, Weld, and Larimer Counties. ERZ 1 presents energy development opportunities for natural gas, wind, and thermal resources.

ERZ 2 (East-central Colorado)

Includes all or part of Yuma, Washington, Adams, Arapahoe, Elbert, El Paso, Lincoln, Kit Carson, Kiowa, and Cheyenne Counties. ERZ 2 presents energy development opportunities for natural gas, wind, and thermal resources.

ERZ 3 (Southeast Colorado)

Includes all of part of Baca, Prowers, Kiowa, Crowley, Otero, Bent, and Las Animas Counties. ERZ 3 represents the potential for wind resource development.

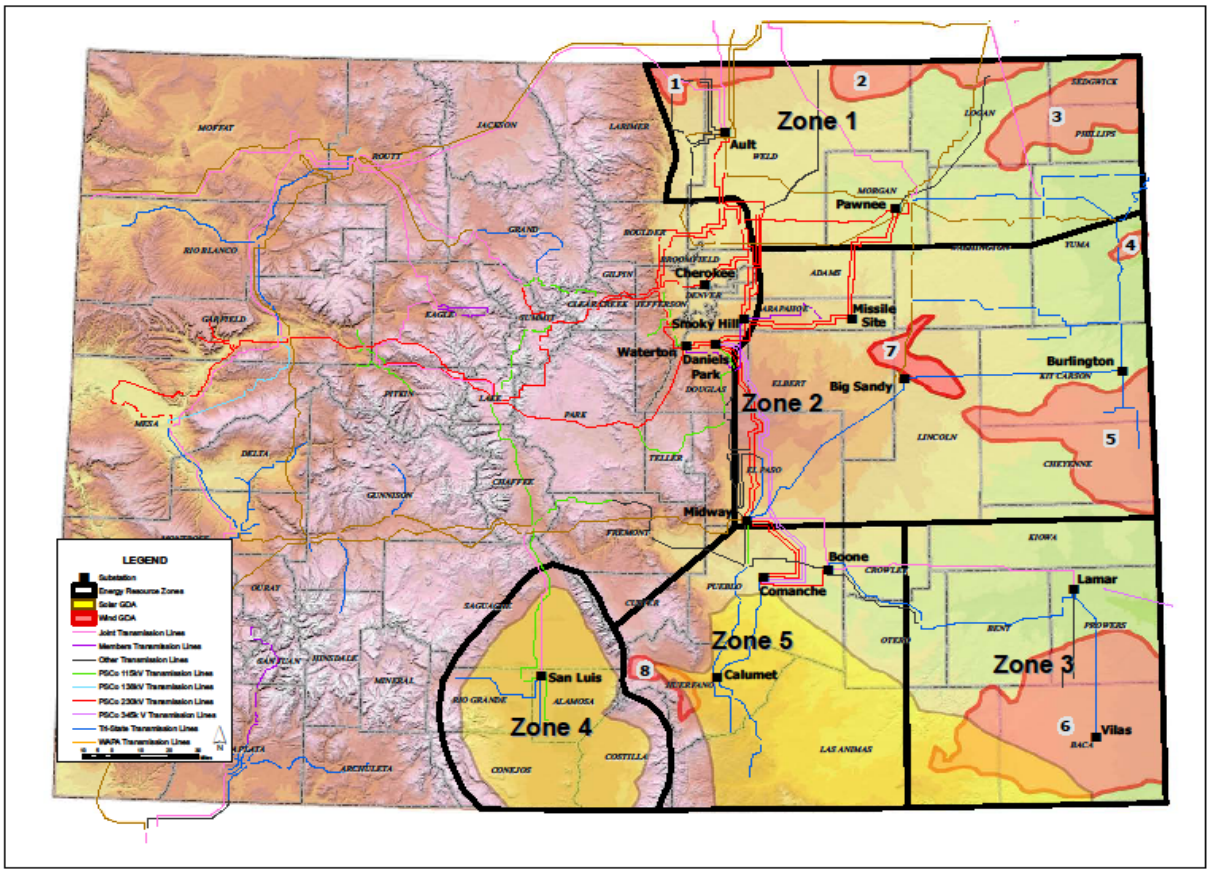
ERZ 4 (San Luis Valley)

Includes all or part of Costilla, Conejos, Rio Grande, Alamosa, and Saguache Counties. ERZ 4 presents energy development opportunities for solar resource development.

ERZ 5 (South-central Colorado)

Includes all or part of Huerfano, Pueblo, Otero, Crowley, Custer, and Las Animas Counties. ERZ 5 in South Central Colorado includes the area around Pueblo and south along the I-25 corridor which includes both potential wind and solar resources.

Figure 7. Map of SB07-100 Energy Resource Zones



In addition to the public policy requirements of SB07-100, all three Companies may be subject to federal and Colorado state regulations related to carbon emission reductions from existing power plants. The EPA's Clean Power Plan, which was finalized in late-2015, never went into effect and the EPA has stated that it intends to replace the CPP with new rules. While the specifics of a CPP replacement remain to be determined, the Companies anticipate that any such regulations may impact transmission plans in the 10-Year planning timeframe. The Companies will continue to coordinate with each other and stakeholders with respect to the transmission planning implications of such new federal regulations and expect to address this issue in the next 10-Year transmission plan.

A. Black Hills Summary

Black Hills encouraged all interested parties to participate in the 2017 SB07-100 study process. An open stakeholder SB07-100 Kick-off Meeting was held in conjunction with the Q1 Black Hills Colorado Transmission ("BHCT") Transmission Coordination and Planning Committee ("TCPC") on March 30, 2017 to inform stakeholders of the proposed study plan and to provide an opportunity for suggestions and feedback on the study process. The Kick-off Meeting had no external participants. Follow-up web conferences were held on June 27, 2017 and October 18, 2017 to provide the stakeholders with updates to the study progress and provide further opportunities for input to the process. Meeting notices and presentations were distributed via email and posted on the Black Hills OASIS page at http://www.oatioasis.com/bhct/, as well as on a Colorado SB07-100 webpage established on the Black Hills Corporation website at https://www.blackhillsenergy.com/your-neighborhood/transmission-distribution/transmission-planning/colorado-electric-senate-bill-07.

For the 2017 SB07-100 cycle, Black Hills selected to re-evaluate the resource injection capacity from ERZ-5, which was initially performed as part of the 2013 SB07-100 cycle. That decision was based on the completion of transmission system upgrades since that time as well as ongoing interest to develop generation in the area as indicated by Black Hills' generation interconnection queue. The 2027 heavy summer ("2027HS") CCPG compliance study case was used as the starting point for this study. The analysis included scenarios with the Lamar DC Tie at 200 MW East-West and 200 MW West-East.

Resource injections were evaluated on the existing transmission system, including currently planned upgrades. That injection capability was also assessed assuming a hypothetical 230 kV line from Boone to Walsenburg, bisected by a 230/115 kV interconnection at the existing Rattlesnake Buttes substation. This hypothetical line was previously in Tri-State's list of conceptual projects, driving the decision to include it in this analysis.

The 2027HS study results indicated the BHCE transmission system could accommodate a maximum of 219 MW injection from ERZ-5 via the Rattlesnake-Reader 115 kV line, due to the thermal limit of the transmission line. This is a total amount rather than an incremental amount. That assumes the removal of terminal limitations on the Reader-Pueblo 115 kV line and the rebuilding of the Desert Cove-Fountain Valley-Midway 115 kV line. The 27HS case also indicated that a new Rattlesnake Butte 230 kV bus intersecting the hypothetical Boone-Walsenburg 230 kV line could accommodate an additional 525 MW of generation. This reflects a significant increase from the findings of the 2013 analysis. That increase is primarily attributed to the transmission system upgrades that have been completed since 2013. Another likely contributing factor is differences in generation dispatch patterns in the general study area, which can have a significant impact on results. It is prudent to evaluate any identified upgrades in the context of resource needs and system capabilities.

The Black Hills 2017 SB07-100 Study Report is included in Appendix L for reference.

Black Hills SB07-100 Conclusions

Black Hills utilized an open and transparent process in conducting its 2017 Colorado Senate Bill 07-100 study. Stakeholders were provided several opportunities for involvement and input into the study process and scope. Through this process, Black Hills believes it has fulfilled the requirements of Colorado Senate Bill 07-100, codified at Colo. Rev. Stat. § 40-2-126.

Designate Energy Resource Zones.

On November 24, 2008, Public Service filed with the Commission an information report which identified its five ERZs within Colorado. Four of the ERZs identified by PSCo are located in close geographical proximity to the Black Hills system, specifically ERZs 2, 3, 4 and 5. In the 2011 SB07-100 study report Black Hills identified two ERZs (ERZ-1 & ERZ-2), both of which were located within the PSCo defined ERZ-5. In order to avoid confusion Black Hills has adopted the five PSCo defined ERZs within Colorado.

Develop plans for the construction or expansion of transmission facilities necessary to deliver electric power consistent with the timing of the development of beneficial energy resources located in or near such zones.

Black Hills identified the impacts of the various resource scenarios on the Black Hills transmission system and identified projects which ensure reliable delivery of beneficial energy resources from the designated ERZ-5 to customer loads.

Consider how transmission can be provided to encourage local ownership of renewable facilities, whether through renewable energy cooperatives as provided in Colo. Rev. Stat. § 7-56-210, or otherwise.

The identified new transmission projects will facilitate renewable resource development in ERZ-5 in excess of Black Hills' forecasted resource needs. The studied resource injections are in relatively close proximity to Black Hills customers and would be facilitated by a direct physical connection to the Black Hills electric system.

Submit proposed plans, designations, and applications for Certificates of Public Convenience and Necessity to the Commission for simultaneous review.

Black Hills believes that the 115 kV transmission projects it has identified to facilitate the reliable delivery of beneficial energy resources to customer load are "in the ordinary course of its business" and do not require CPCNs, pursuant to Colo. Rev. Stat. §§ 40-2-126(3) and 40-5-101. This excludes the hypothetical Boone-Walsenburg 230 kV line, which is not being proposed at this time. The resource injection amounts identified in this report are indicative of potential system performance under the evaluated scenarios but should not be construed to reflect firm system capability. In-depth analysis and coordination is required to establish a more comprehensive projection of potential system performance following implementation of the identified system upgrades.

B. Public Service Summary

Public Service began filing SB07-100 reports in October 2007. Public Service has developed plans for nine transmission projects to expand transmission capability for the

delivery of beneficial energy resources from ERZs. These projects are listed in Table 13.

Public Service has completed the first four projects listed in Table 13. These projects have enabled us to interconnect 1400 MW of wind in eastern and northeastern Colorado, and will accommodate an additional 600 MW of wind from the Rush Creek Wind Project, when the Pawnee – Daniels Park Project is completed. The tables below list the name of the project, the ERZ that the project would serve, and a tentative schedule for implementation. The status of these projects is described in more detail in Section III.

Table 13. Public Service SB100 Projects

	Project	ERZ	ISD	Status
1	**Missile Site 230 kV Switching Station**	2	2010	Project placed in-service November 2010.
2	**Midway-Waterton 345 kV Transmission Project**	3,4,5	2011	CPCN granted on 7/16/2009. Project placed in-service May 2011.
3	**Pawnee-Smoky Hill 345 kV Transmission Project**	1,2	2013	CPCN granted on 2/29/2009. Project placed in-service June 2013.
4	**Missile Site 345 kV Substation**	2	2012	CPCN granted on June 8, 2010. Project placed in-service December 2012.
5	**Pawnee-Daniels Park 345 kV**	1,2	2019	CPCN granted on April 9, 2015. In-service date planned for 2019.
6	**Lamar-Front Range 345 kV**	2,3	TBD	Studies complete. No plans for full build out at this time. Certain segments may be implemented in a phased approach.
7	**Lamar-Vilas 230 kV**	3	TBD	(See Lamar – Front Range)
8	**Weld County Expansion (formerly TOT 7 Expansion Plan)**	1	TBD	Technical studies ongoing
9	**San Luis Valley Transmission Plan**	4,5	TBD	Technical studies ongoing

1. Projects That Have Been Completed or Planned

Missile Site 230 kV Switching Station (ERZ-2)

The Missile Site 230 kV Switching Station Project consisted of a new switching station near Deer Trail, Colorado that connects the existing Pawnee-Daniels Park 230 kV transmission line into and out of the Missile Site 230 kV Switching Station. The project has allowed interconnection of new generation in ERZ-2.

The Missile Site 230 kV Switching Station was placed in-service in November 2010. Public Service interconnected the 250 MW Cedar Point wind project in 2011.

Missile Site 345 kV Switching Station (ERZ-2)

The Missile Site 345 kV Substation expanded the Missile Site 230 kV Switching Station to allow additional generation and transmission interconnections from ERZ-2 at the 345 kV voltage level. The Substation bisects the Pawnee-Smoky Hill 345 kV Transmission Project. In addition to connecting the Pawnee-Smoky Hill 345 kV line, the Substation also allows for future 345 kV transmission connections. These include connections to the Pawnee-Daniels Park 345 kV Project. The Missile Site 345 kV Substation was placed in-service in December 2012. About 600 MW of wind generation has been interconnected to Missile Site 345 kV. The Rush Creek Project will interconnect another 600 MW in 2018.

Midway-Waterton 345 kV Transmission Project (ERZs 3, 4, and 5)

The project consists of 82 miles of 345 kV transmission line from the Midway Substation, near Colorado Springs, to the Waterton Substation, southwest of Denver. The Midway-Waterton 345 kV project accommodates additional generation resources in ERZs 3, 4, and 5. The Midway-Waterton 345 kV Transmission Project was placed in-service in May 2011.

Pawnee-Smoky Hill 345 kV Transmission Project (ERZs 1 and 2)

This project consists of developing approximately 95 miles of 345 kV transmission line between the Pawnee Substation near Brush, Colorado, and the Smoky Hill Substation, east of Denver. The project allowed for additional resources in ERZ-1 and ERZ-2, interconnected at or near the Pawnee and Missile Site Substations. The project was designed to facilitate construction of the Pawnee-Daniels Park 345 kV Project. This project was placed in-service in June 2013.

Pawnee-Daniels Park 345 kV (ERZs 1 and 2)

The Pawnee-Daniels Park 345 kV Transmission Project is described in Section III.C.2. The project consists of building a 125-mile 345 kV transmission line from the Pawnee Substation in northeastern Colorado to the Daniels Park Substation, south of the Denver-Metro area. The project will also result in constructing a new Harvest Mile 345 kV Substation, near Smoky Hill Substation, and a new Harvest Mile-Daniels Park 345 kV line. The project will also interconnect with the Missile Site 345 kV Substation. This project was planned in accordance with Senate Bill 07-100 in that it will accommodate generation in designated Energy Resource ERZs 1 and 2. The project is scheduled to be placed in-service in October 2019, with an estimated cost of $178.3 million.

2. Conceptual Plans

The projected in-service dates of these conceptual projects identified in Table 13 above can be affected by CPCN approval, revisions to load forecasts, resource plans, siting and land permitting, coordination of construction outages, and material delivery times. Because all of these projects are presently in the conceptual stage, assessments will continue on whether the stated factors will cause any modifications to these projects, in terms of configuration, timing, or otherwise.

Lamar-Front Range 345 kV (ERZs 2 and 3)

This project is described in Section III.C.2 and was planned to accommodate resources in ERZs 2 and 3. The Lamar-Front Range project, as presently envisioned, is estimated

to cost approximately $900 million. The planning studies have been completed and project study reports are available at the CCPG web site http://regplanning.westconnect.com/ccpg.htm under the Lamar-Front Range Project. As mentioned in previous SB100 and Rule 3627 filings, no decisions have been made with respect to implementation. Both Tri-State and Public Service continue to evaluate what strategies are most appropriate for moving forward. Recently, Tri-State and Public Service have been planning and implementing projects that align with the Lamar-Front Range plan. These include the Tri-State Burlington-Lamar 230 kV and Boone-Lamar 230 kV Transmission Projects and the Public Service Rush Creek-Missile Site 345 kV Project.

Lamar-Vilas 230/345 kV (ERZ-3)

The Lamar-Vilas project is associated with the Lamar-Front Range Plan. The Lamar-Vilas portion was planned to consist of approximately 60 miles of high-voltage transmission from the existing Lamar Substation to the existing Vilas Substation to provide access to additional resources in ERZ-3.

Weld County Expansion (ERZ-1)

This plan is described in Section III.B.2 as a means to accommodate additional generation resources in ERZ-1. As a result of volatility in oil and gas prices in Northeast Colorado, and the Public Service plan to replace aging 44 kV infrastructure around Greeley, other projects have been planned in the area that align with, and may ultimately replace or become the Weld County Expansion Project. Public Service is implementing the Ault-Cloverly Project and is developing additional plans for the area south of Greeley. Tri-State planned SWEP, which will connect transmission from the Denver-Metro area to the south of Greeley system. The CCPG NECO Subcommittee has been working to develop a comprehensive transmission plan for Northeast Colorado to serve a variety of needs. When specific projects have been recommended, Public Service will inform stakeholders and develop plans for implementation.

San Luis Valley (ERZs 4 and 5)

This plan has been described in Section III.B.2 and has been planned as a means to accommodate potential generation from ERZs 4 and 5, in addition to improving the reliability of the transmission system in the San Luis Valley area of Colorado. Studies have been taking place in the CCPG San Luis Valley Subcommittee, which has been led by Public Service and Tri-State. As specific projects are planned and recommended, Public Service will inform stakeholders and develop plans for implementation.

VI. Stakeholder Outreach Efforts

Per Rule 3627(g), “Government agencies and other stakeholders shall have an opportunity for meaningful participation in the planning process.” “Government agencies include affected federal, state, municipal and county agencies. Other stakeholders include organizations and individuals representing various interests that have indicated a desire to participate in the planning process.” (Rule 3627(g)(I)) The following sections summarize each Company's approach to government agency and stakeholder outreach and participation pertaining to Rule 3627. Processes specific to the stakeholder input directives of FERC Order No. 890 are discussed in Section VI.D.

A. Black Hills Outreach Summary

Black Hills recognizes the importance of stakeholder involvement throughout the transmission planning process, and considers a stakeholder to be any person, group or entity that has an expressed interest in participating in the planning process, is affected by the transmission plan, or can provide meaningful input to the process that may affect the development of the final plan.

Stakeholders are encouraged to participate in Black Hills’ transmission planning through the regular meetings held by the TCPC as part of the annual study process under FERC Order No. 890. The TCPC is an advisory committee consisting of individuals or entities that are interested in providing input to Black Hills’ Transmission Plan. The TCPC study process consists of a comprehensive evaluation of the Black Hills and surrounding transmission systems for critical scenarios throughout the 10-Year planning horizon. Stakeholders are notified of the initial meeting at the start of the study cycle and invited to participate. An opportunity is provided to comment on the scope of the study at this point in the process. Relevant system modeling data is requested from the stakeholders, as well as any economic study or alternative scenario requests. Once the study cases are compiled, another open stakeholder meeting is held to review and finalize the data and study scope. A third stakeholder meeting is held to review preliminary study results and discuss potential solutions to any identified problems. This process allows the TCPC to develop a comprehensive transmission plan to meet the

needs of all interested parties. A final stakeholder meeting is held to approve the study report and Local Transmission Plan ("LTP"). Following each meeting, contact information for the transmission planner performing the study is provided to allow for ongoing questions or comments regarding the study process. Updates on the progress of the TCPC study efforts are also provided to regional planning groups, such as the CCPG, to promote involvement from a larger stakeholder body.

A list of potential stakeholders was created during the initial TCPC study cycle and has continued to evolve through active invitations, recommendations from existing participants and outreach at CCPG meetings. Black Hills is continually modifying its stakeholder list in order to invite a more comprehensive group of participants into the transmission planning process.

Three quarterly meetings were held in 2017 as part of Black Hills' annual TCPC process. Meeting notifications were sent to the stakeholder contact list, announced at the CCPG meetings and posted on Black Hills' OASIS web page.

Black Hills' Q1 stakeholder meeting is typically more educational in nature and was held via web/phone conference on March 30, 2017. It served the purpose of presenting the transmission planning process to stakeholders, describing the scope of the 2017 assessment, reviewing the current 10-Year Transmission Plan and soliciting feedback on the study scope, the stakeholder outreach process and potential alternatives to the projects within the 10-Year Plan.

Black Hills' Q2 stakeholder meeting was held on June 27, 2017 via web/phone conference to review the data submittals for the computer-based transmission system model and obtain stakeholder approval on the final study scope.

Black Hills' Q3 stakeholder meeting was held on October 18, 2017 via web/phone conference to present initial study results and identified system needs. The results of the Senate Bill 07-100 analysis were not available at this meeting.

The Black Hills stakeholder meeting that is typically reserved for Q4 was scheduled for Q1 2018. The purpose of this meeting is to present final study results and recommended project alternatives for stakeholder review. The results of the SB07-100 analysis were compiled and the report was also included in the Q1 stakeholder meeting agenda. Those results were also summarized in Section V of this report.

A limited number of external stakeholders attended the quarterly meetings. The stakeholder meetings produced some dialog on specific projects, but substantive feedback regarding the planning process and future projects was not received. Black Hills relied heavily on coordination with affected utilities and internal review of alternatives to ensure that the projects selected and presented in the Rule 3627 Transmission Plan were optimal and adequate for the needs of its network transmission system and Colorado's goals of fostering beneficial energy resources to meet load growth.

For more information regarding the stakeholder process utilized in the 2017 or earlier Black Hills TCPC planning processes, including meeting notices, notes, presentations and contact information, refer to the Stakeholder Outreach section of the Black Hills transmission planning web site at:

www.blackhillsenergy.com/your-neighborhood/transmission-distribution/transmission-planning/colorado-electric-rule-3627.

Stakeholder outreach information is also available in the Transmission Planning folder on the Black Hills OASIS at:

http://www.oatioasis.com/bhct

B. Tri-State Outreach Summary

Tri-State performs transmission planning-related stakeholder outreach as a standard part of its day-to-day business consistent with its policy of planning in an open, coordinated, transparent and participatory manner. This outreach encompasses various efforts including: Rule 3627 specific meetings and stakeholder communications; FERC

Order No. 890 specific meetings and communications; project-specific meetings and communications; and CCPG participation.

As described in Rule 3627(g)(I), stakeholders include federal, state, county, and municipal government agencies as well as other non-governmental organizations and individuals having an interest in the transmission planning process. Tri-State identifies potential governmental stakeholders based generally on a five-mile area surrounding proposed transmission facilities. Federal agencies in the areas of the transmission projects included in Tri-State's 2018 10-Year Transmission Plans typically include the Bureau of Land Management, the U.S. Forest Service, the National Park Service, and the Department of Defense. Potentially interested state agencies include the Colorado State Land Board and associated Stewardship Trust Lands, and the Colorado Division of Parks and Wildlife. Outreach to county and local governments typically includes communications to relevant elected officials as well as administrators, managers, and land planning, economic development, and legal staffs. In some instances, Tri-State's governmental outreach also included agencies such as parks and school districts.

Contact lists for non-governmental stakeholders were developed through various transmission planning forums such as CCPG and other WestConnect planning groups, as well individuals and organizations that have participated in previous Tri-State stakeholder meetings. When known, Tri-State also included stakeholders identified as being interested in specific proposed projects. The resulting non-governmental stakeholders included other utilities, Tri-State Member Systems, energy and transmission project developers, environmental groups, economic development organizations, various advocacy groups, and elected officials not already included in the governmental outreach communications.

In 2017, Tri-State hosted two transmission planning-related stakeholder outreach meetings in connection with development of the 2018 10-Year Transmission Plan. The first meeting was on May 12, 2017, and provided a summary of new information related to Tri-State's ongoing transmission planning activities as well as updates on current projects and coordination with CCPG's long range transmission planning efforts. This

meeting also constituted Tri-State's FERC Order No. 890 stakeholder meeting and provided an opportunity for stakeholders to provide input in connection with all of Tri-State's long-range transmission plans. All such input and relevant alternatives were considered and included in the appropriate biennial transmission plans submitted to the Colorado Public Utilities Commission pursuant to Rule 3627.

The second stakeholder outreach meeting was held on August 18, 2017. This meeting did not introduce new information as long-term plans typically do not change within the short period between outreach meetings. Rather, this meeting provided an additional opportunity for continued stakeholder participation in the transmission planning and input with regard to Tri-State's long-range transmission plans. Input received at this meeting was either considered in connection with Tri-State's 2018 10-Year Transmission Plan or will be considered in connection with the development of future 10-Year plans developed pursuant to Rule 3627. No alternatives were proposed at this meeting.

In addition to these larger stakeholder meetings addressing system-wide and Colorado-specific transmission projects, Tri-State also conducted a number of meetings related to individual proposed transmission projects. These meetings and other project-related communications included relevant government agencies, economic development entities, and other interested organizations and persons to inform them of the proposed project and provide an opportunity for feedback and consideration of potential alternatives. The nature and timing of outreach efforts related to specific projects was generally dependent on the development status of the project.

Details of Tri-State's meetings, including a list of attendees and a meeting presentation video which includes questions and comments received together with Tri-State's responses thereto, and relevant presentations can be found on Tri-State's website, (select "Operations" then "Transmission Planning").

Tri-State also participates in the CCPG's transmission planning efforts. As discussed in Section V.D. of this Plan, the CCPG planning process includes additional stakeholder

outreach and a further opportunity for stakeholder participation in and input into the overall Colorado coordinated transmission planning process, which includes Tri-State's proposed projects. Additional information concerning CCPG stakeholder opportunities is available at the WestConnect website.

Tri-State confirms that, as required by Commission Rule 3627(g)(V), this 2018 10-Year Transmission Plan is available to all government agencies and other stakeholders through Tri-State's Transmission Planning website.

Tri-State has informed all stakeholders of the availability of the 2018 10-Year Transmission Plan.

C. Public Service Outreach Summary

Rule 3627 requires a summary of stakeholder participation and input and how this input was incorporated in the transmission plan. The rule states that government agencies and other stakeholders shall have an opportunity for meaningful participation in the planning process. The government agencies include affected federal, state, municipal and county agencies. In addition, other stakeholders including organizations and individuals representing various interests that have indicated a desire to participate in the planning process shall also have an opportunity for meaningful participation. Under the rule, Public Service is required to actively solicit input from the appropriate government agencies and stakeholders to identify alternative solutions. The following is a synopsis of the outreach that the Company performed relevant to this rule.

Rule 3627 Webinar

The Company developed an informational PowerPoint presentation that included information on the long-range plans developed as part of Rule 3627. The hour-long webinar held on Thursday, August 10, 2017, was designed to give stakeholders the option of participating and commenting on transmission plans, either in person (at the Xcel Energy offices in Downtown Denver) or via Internet. An email invitation with exact verbiage can be provided at the request of the Commission.

More than 500 individuals representing the following stakeholder groups—including all state legislators in both the House and Senate—received invitations to the webinar:

- Elected officials
- Federal, state and local government officials
- Environmental groups
- Energy developers
- Chambers of Commerce
- Business and industry
- Planning and economic development agencies
- Large energy users
- Citizens and advocacy groups
- Interveners on past Public Service filings
- Organizations involved in transmission planning (e.g., CCPG members)

Invitations were also sent to the CCPG's distribution list, which includes representatives from other utilities including Black Hills, WAPA and Tri-State, as well as stakeholders representing environmental interests, consulting firms, law firms, and other individuals and groups. Local government elected officials including county commissioners in counties which could be impacted by projects in the 10-Year plan were also invited along with local planning office representatives, and other staff officials from local governments and agencies. Because routing has not been started on some of these projects, which were still in the planning phase, individual landowners who might be impacted were not identified.

Information on Xcel Energy's Transmission Projects in Colorado was provided to all invitees via a link in the email, but since then the web address was redirected to the following: http://www.transmission.xcelenergy.com/Projects/Colorado

Attendance at the August 10, 2017 session included five in-person attendees external to the Public Service Transmission organization and approximately 15 webinar attendees, although an actual count was difficult to gauge as participants dropped and added during the course of the presentation. Since self-identification was optional, it was not possible to know if new people were added or if connections had been lost to some attendees and they opted to re-connect during the webinar.

The PowerPoint presented at the session consisted of three basics parts. Because the level of knowledge surrounding transmission and transmission planning of the attendees was not known, part one provided an overview of electric transmission to acquaint attendees with basic information about how the system works and what constitutes the transmission system. Part two covered the transmission planning process, provided an overview of how and why planning is done, and outlined the many factors that are considered when developing plans. Part three reviewed all projects included in Public Service's 10-Year Plan. Public comment from the webinar covered a wide range of topics.

FERC Order 890 Stakeholder Meetings

The Company facilitates two open stakeholder meetings per year to meet the requirements of FERC Order 890. The meetings are held in the first and fourth quarter every year at the Xcel Energy office in Denver, and the content is very similar to that presented in the Rule 3627 webinars. In the last two years, FERC Order 890 meetings were held on March 17, 2016, December 7, 2016, March 27, 2017, and December 6, 2017. Public Service has taken a similar approach as Tri-State, where the Rule 3627 and FERC Order 890 meetings are referred to as open stakeholder meetings that will meet the objectives of both rules. Meeting agendas, presentations (referred to as "Transmission Plans", and notes are available at: http://www.oatioasis.com/psco/index.html under "FERC 890 Postings".

PROJECT-SPECIFIC OUTREACH

Pawnee-Daniels Park Project

Public Service proposed to construct a new 345 kV transmission line to connect the existing Pawnee Substation near Brush, Colorado, to the Daniels Park Substation south of the Denver metro-area. The 125-mile project is part of Public Service's Senate Bill 07-100 portfolio of transmission plans and is a critical component of the Colorado long-range transmission plan. The Pawnee-Daniels Park project will relieve transmission constraints and accommodate new generation resources in ERZ 1 and 2.

Public Service's outreach efforts began in July of 2013 when the Company started meeting with various residents, non-governmental organizations, elected officials, Homeowners Associations ("HOAs"), senior planning staff and other stakeholders. The company hosted a series of large scale open house meetings throughout 2014 and 2015. Alternative transmission line routes were analyzed, narrowed down and shared with the public at another series of open house meetings held on September 29, 30 and October 1, 2015. All of the information presented at the open house meetings was posted to the project website: http://www.transmission.xcelenergy.com/Projects/Colorado/Pawnee-Daniels-Park-Project-(SB100)), which is continually updated as new developments occur. Comments from the open houses were summarized and included in the Company's local land use permit applications filed in 2016 with Arapahoe County, Douglas County and the Town of Parker and in 2017 with the City of Aurora.

The CPCN application to the PUC was submitted on March 28, 2014 with a hearing in front of the Administrative Law Judge ("ALJ") on September 9, 2014. Prior to the hearing, the ALJ decided to hold a public comment hearing in response to the opinion letters received by the public. The public comment hearing was held on July 23, 2014 at the Parker Arts and Cultural Events Center. Here, the public were able to voice their concerns and opinions of the project. The Colorado PUC approved the CPCN for the Pawnee-Daniels Park Project on April 9, 2015. The CPCN included an in-service date for the project of May 2022 with construction beginning in 2020. However, in late 2015,

Congress extended the Production Tax Credit for new wind generation projects, but with a declining recovery schedule for projects that start construction after 2016. As a result of this, the Company filed with the CPUC asking them to modify their previous decision in order to accelerate the in-service date to October 2019 and the construction start date to January 2017 for the Smoky-Hills Daniels Park portion of the project. In September 2016, the Company, along with multiple parties, agreed to a settlement that included moving the in-service date to 2019. The settlement agreement was approved by the CPUC on September 30, 2016. On October 20, 2016 the CPUC issued its written approval.

Avery Substation Project

Public Service is proposing to construct the Avery Substation and Transmission Line project. The new Avery Substation will enable the Company to serve existing and new load in the vicinity of Timnath, Severance and Windsor caused by growth of these communities along the Interstate 25 corridor. Avery Substation will assist in providing back up to the existing Cobb Lake and Windsor Substations, which are reaching their capacity. It also will provide reliability to our existing and future customer load. The project consists of a new electric distribution substation, an associated overhead double-circuit 230 kV electric transmission line and overhead distribution feeder lines near the towns of Windsor, Severance and Timnath, Colorado. Power for the proposed half mile to 3-mile 230 kV transmission line will be provided by interconnecting the existing PRPA Timberline-Ault 230 kV transmission line. Public Service is currently evaluating alternatives for this interconnection. This connection will supply the proposed Avery Substation with the electrical supply needed to power the distribution feeders serving the immediate communities.

At the first open house meeting the Company provided information, asked for the public's input and answered questions about the project. A series of graphic materials and other information was on display and a project website was made available at www.xcelenergy.com/Avery. In addition to submitting written comments at the open house, the public is allowed to provide comments and suggestions via the website.

Direct mail pieces were sent out to 120 landowners and other stakeholders; a total of 15 attended the meeting. The meeting took place at the following location:

Wednesday, September 5, 2012; 4-7pm
Windsor Recreation Center, Windsor, Colorado

Due to siting difficulties and a major lapse in time, Public Service decided to conduct another open house meeting to update the public and solicit further comments and suggestions. The project website stayed up to date during the lapse and people were again encouraged to provide comments and suggestions. Direct mail pieces were sent out to 140 landowners and stakeholders; a total of 8 attended the meeting. The format for the open house was the same as the first and was held at the following location:

Thursday, May 29, 2014; 5-7pm
Windsor Recreation Center, Windsor, Colorado

A CPCN was filed with the CPUC on March 13, 2015. The CPUC approved the CPCN application on May 13, 2015. The project has a target in-service date of May 31, 2019.

Through October 31, 2016, the Company continued to seek public comment as alternative routes and substation sites were considered. New routes and sites were selected with in larger area of interest, so it was decided to hold one last open house meeting to solicit comments. Direct mail pieces sent out to 635 landowners and stakeholders; a total of 37 people attended the meeting, which was held at the following location:

Wednesday, August 24, 2016; 5-7pm

Hilton Garden Inn Fort Collins, 2821 E. Harmony Road.

Moon Gulch Substation Project

The proposed Moon Gulch Substation project consists of a new 230 kV substation in northwest Arvada, Colo. The substation will serve a rapidly developing area in the west/northwest Denver metropolitan area of Broomfield, Jefferson and Boulder counties. The proposed location is near Candelas Parkway off of State Highway 72 in

Arvada. The Colorado Public Utilities Commission approved a Certificate of Public Convenience and Necessity application for the project on January 20, 2016. The parcel of land associated with the proposed location was rezoned to allow for a substation. The rezoning process requires a neighborhood meeting prior to staff review of the rezoning application. The meeting was held at the Candelas Recreation Center, 9371 McIntyre Street, Arvada, near the substation site on February 18, 2016. Notices were mailed to the four adjoining property owners. The meeting notice was also posted on the neighborhood website. Approximately 15 persons attended the meeting. Thirteen questions were asked during the meeting. In addition, the Arvada Planning Commission and City Council held public hearings on the rezoning application. A website for the project was established at:

http://www.transmission.xcelenergy.com/Projects/Colorado/Moon-Gulch-Substation.

Ault-Cloverly 230/115 kV Transmission Project

The Ault-Cloverly 230/115 kV Transmission Project will increase electric reliability and load-serving capability of the Xcel Energy electric transmission system in and around the Greeley area, and will provide accommodation for new generation resources in the region while aligning with other transmission planning efforts in the area. The Company filed a CPCN application with the CPUC on March 9, 2017 to construct the Northern Colorado Area Plan; Proceeding Number 17A-0146E.

The Company held the first public open house meeting for the project, where over 100 landowners within ½ mile of proposed corridors and local stakeholders were notified for the WAPA Ault-Husky substation portion of the project. The meeting was also publicly noticed with a display ad in the local newspaper. Fourteen people attended the first meeting, which was held in the following location: Thursday, October 26, 2017; 4-8 PM at the Highland School District Re-9 Administration Building, Ault, Colorado.

The Company provided background information for the purpose and need of the project, asked for the public's input, and answered questions about the routing, siting, and

construction of the project. A series of graphic materials and other information was on display, provided as handouts, and a project website was made available at: http://www.transmission.xcelenergy.com/Projects/Colorado/northern-colorado-area-plan. In addition to submitting written comments at the open house, the public is allowed to provide comments and suggestions via the website, email, or telephone through a dedicated 1-888 number. The Company intends to schedule 1-2 additional public open house meetings in early 2018.

Rush Creek 345 kV Transmission Line Project

The Company held a series of public open house-style meetings during the transmission line routing process. Over 2000 invitations were mailed to landowners within one mile of proposed corridors and the windfarm area, as well as local/regional stakeholders in the five-county project area. The meetings were publicly noticed in four local newspapers. Over 235 people attended the public meetings, which were held at the following locations:

Wednesday, May 25, 2016; 5-7 pm
Big Sandy School Cafeteria, Simla, Colorado

Thursday, May 26, 2016; 5-7 pm
Lincoln County Fairgrounds Event Building, Hugo, Colorado

Thursday, June 2, 2016; 5-7 pm
Deer Trail High School Gymnasium, Deer Trail, Colorado

Monday, June 6, 2016; 5-7 pm
Stratton Activities Center, Stratton, Colorado

Tuesday, June 7, 2016; 5-7 pm
Kit Carson City Hall, Kit Carson, Colorado

At each of the open house meetings, the Company provided information, asked for the public's input and answered questions about the project. A series of graphic materials and other information was on display and a project website was made available at http://www.transmission.xcelenergy.com/Projects/Colorado/Rush-Creek-Connect. In addition to submitting written comments at the open house, the public was allowed to provide comments and suggestions via the website, email, or telephone through a

dedicated 1-888 number. The Company sought public comment through the submission of the transmission line routing applications to Arapahoe, Elbert, and Lincoln counties in the summer of 2016.

Thornton Substation

Since initiating public outreach in 2014 and to support land use permitting, the following activities have been completed:

- Considered and vetted more than three dozen sites against electrical and land use criteria
- Reviewed and responded to 300+ comments, email messages, and hotline inquiries
- Held six public meetings and open office hours held between 2014 and 2017 attended by 250+ members of the community
- Mailed 15,000+ postcards and notifications to landowners and stakeholders
- Held several one-on-one and group meetings with property owners, HOAs, and business owners
- Met with Adams 12 school district and Thornton Fire Department to discuss student and public safety concerns
- Met/exceeded city and county notification requirements for the neighborhood meeting - mailer to property owners in 1,500-foot notification radius and newspaper ads; announcements also made via email and social media
- Reviewed and responded to 300+ comments, email messages, and hotline inquiries
- Established project website (www.xcelenergythorntonsubstation.com), phone number (844.551.6281), and email address (info@xcelenergythorntonsubstation.com) that has been available to the public since 2014.

The Thornton Substation project components were approved by Thornton City Council and Adams County Planning Commission in July 2017 and August 2017. Construction preparation at the project site will begin in November 2017 and is anticipated to continue until mid-2019. Public outreach is anticipated to continue through the completion of construction. A Customer Communication and Public Relations Plan have

been developed for the Project's construction phase and will include the following communication channels:

- Project website and xcelenergy.com updates
- Notification emails to the Project email subscriber list
- Project hotline updates and daily monitoring
- Key stakeholder outreach via presentations, small groups, and one-on-one meetings
- Postcards/Direct mail before and/or following construction milestones
- Door hangers to notify nearby landowners of commencement of construction activities
- Collateral materials including printed materials and magnets
- Traffic signage (electronic and static)
- Social media (through Xcel Energy's Facebook account and monitoring software)
- Xcel Energy Customer Care channels—CCQR and News to Use for agents
- News release(s) to correspond with road/lane closures and key project milestones

D. CCPG Outreach Summary

To ensure stakeholders in Colorado have multiple opportunities to provide input and receive a broader perspective on the evolution of Colorado's transmission system, TPs also leverage the CCPG stakeholder input process in developing the 10-Year transmission plan. CCPG has a subgroup called the 3627 Subcommittee. The Subcommittee serves as a forum for coordination among the Colorado electric utilities that are required to comply with PUC Rule 3627, and for receipt and consideration of stakeholder proposals submitted in connection with 10-Year transmission plans. Since the 2012 filing, TPs have worked with CCPG to formalize and document processes for receiving, evaluating, and providing feedback on stakeholder submitted alternatives. Stakeholders are provided opportunities for meaningful participation through multiple channels, including an online form that can be emailed, by participating in open meetings via teleconference, or by actively attending quarterly meetings. Full documentation of the process by which stakeholder input, suggestions, and alternatives

are to be categorized, evaluated, and recorded is included in Appendix J as well as on the CCPG website.

Generally, the process is initiated by the stakeholder filling out a form and supplying it to the CCPG chair. The form requests the following information:

- Study or project name
- New study or alternative
- Narrative description
- Study horizon date
- Geographic footprint of interest
- Load and resource parameters
- Transmission modeling
- Suggested participants
- Policy issues to address
- Type of study
- Other factors

Once the CCPG chair receives the request, a determination will be made as to whether adequate information has been provided. The chair may contact the requester to ask for additional details. The chair will facilitate an ad-hoc review group ("Review Group") to review and categorize the request. The Review Group will determine:

- If the request is reasonable from a reliability planning perspective.
- Who should be responsible? (CCPG or a smaller sub-group of CCPG; or should the study be forwarded to a larger group such as WestConnect or WECC)?
- The likely schedule for completing the analysis requested.

The Review Group may consider the following questions to determine the response to the request:

- Which portion(s) of the CCPG transmission system shall be under consideration in the study?
- Would the request be of interest to multiple parties?
- Does the request raise policy issues of national, regional, or state interest?
- Can the objectives of the study be met by existing or planned studies?

- Would the study provide information of broad value to customers, regulators, transmission providers and other interested Stakeholders?
- Does the request require an economic (production cost) simulation or can it be addressed through technical studies, (power flow and stability analysis)?

Once the Review Group has determined that the request is reasonable and has verified the purpose and intent of the request, a written response will be developed and provided to the requester and CCPG.

If the Review Group determines that the request cannot be accommodated by CCPG or any TP, an explanation will be provided. If the Review Group determines that the request can be accommodated, then the response will provide information as to the recommended logistics for how the request will be handled, including the responsible parties and a schedule for completion. CCPG maintains a record of all comments and requests received, as well as their disposition. These records will also be posted on the CCPG section of the WestConnect website.

CCPG Green Valley Stakeholder Input Process

At the Public Service March 27, 2017 FERC 890 / Rule 3627 Stakeholder Meeting, a representative of the OCC verbally suggested a study be performed to evaluate new 345 kV transmission that would run from the existing Green Valley Substation to a point on the Pawnee-Missile Site transmission. Public Service responded that the suggestion should follow the CCPG Stakeholder Input Process. On April 6, 2017, the CCPG received a comment form from the OCC representative. The CCPG followed the Stakeholder Input Process and provided a response on June 9, 2017. The stakeholder input and the CCPG response are both included in Appendix J.

CCPG San Luis Valley Subcommittee Stakeholder Input Process

In 2016, the SLV Subcommittee, which was facilitated by Tri-State and Public Service, performed the second phase of studies for the SLV area. The Phase 1 studies and report were described in the 2016 Filing. The Phase 1 Report focused on the reliability portion of the San Luis Valley. The Phase 1 report was accepted by CCPG members posted on WestConnect website on February 1, 2016. At the second quarter 2016

CCPG meeting, the Phase 2 study scope was presented. SLV Subcommittee meetings to address the second phase of studies commenced in June of 2016. The invitation to participate was extended to all CCPG participants, and the SLV Subcommittee followed the CCPG open stakeholder process for planning studies. The purpose of Phase 2 was to build on the results from Phase 1, focus on addressing the export capability beyond the Poncha Substation, and develop a comprehensive transmission plan to meet all of the stated objectives.

The SLV Subcommittee held seven regularly scheduled meetings from February 2016 through December 2016 to discuss study assumptions, study methodology, potential alternatives, cost estimates, and benefits and draft a final study report. The SLV Subcommittee participant list consisted of 17 stakeholders. Meetings were held on:

- February 11, 2016 (CCPG)
- June 3, 2016
- August 15, 2016
- September 15, 2016
- September 18, 2016 (CCPG)
- October 27, 2016
- December 8, 2016 (CCPG)

Stakeholder input resulted in evaluation of the following alternatives:

Alternative 1: New Poncha-Malta 230kV Line

Alternative 2: New Poncha-W.Canon-Midway 230kV Line

Alternative 3: Going west of out of San Luis Valley

Alternative 4: Going south out of San Luis Valley

Sensitivity: Craig Unit #1 Retirement

The final report concluded that Alternatives 1 and 2 met the objectives of the study. All supporting documentation including meeting agendas, presentations, notes, and the final Phase 2 Report are accessible from the CCPG – San Luis Valley Subcommittee website located at:
http://regplanning.westconnect.com/ccpg_san_luis_valley_sc.htm

CCPG Northeast Colorado Subcommittee Stakeholder Input Process

The CCPG NECO Subcommittee is the forum for coordinated planning of the transmission system that generally covers Weld, Morgan, Adams, Washington, Logan, Sedgwick, Phillips and Yuma counties and also extends to portions of Boulder and Larimer counties. The objective of the NECO Subcommittee was described in the 2016 Filing and consists of developing transmission plans that will support and facilitate load growth related to oil and gas development, coordinate with reliability improvements in the Greeley area, and complement other longer-term transmission plans in northeast Colorado. The NECO Subcommittee focused on transmission plans for the Northern Greeley (or more accurately the "North of Greeley") area in 2016. The study was limited to the transmission system in northeast Colorado, commonly referred to as the Foothills area, which is primarily within Weld County, but also extends to Boulder and Larimer Counties. The objectives of the studies were to:

1. Replace the existing 44 kV system with higher voltage transmission facilities;
2. Improve the load-serving capability of the region;
3. Allow for the accommodation of additional beneficial generation resources; and
4. Establish a plan that can coordinate with future transmission plans and initiatives.

The subcommittee met almost every month, including:

- January 6, 2016
- February 4, 2016
- March 10, 2016
- April 14, 2016
- May 25, 2016
- June 20, 2016
- July 26, 2016

Based on stakeholder input, at least twelve alternatives were considered to meet the objectives. Ultimately, the subcommittee recommended the Ault-Cloverly Transmission project. The results of the study effort were documented in the Northern Greeley Area Transmission Plan System Impact Study Report. On February 16, 2017, the CCPG agreed that this report met the objectives of the scope, and the results were technically adequate and accurate. One party, the Office of Consumer Counsel, did not agree with the rest of CCPG.

Public Service filed for a CPCN for the Northern Greeley Area ("Ault-Cloverly") Transmission Project in 2017,[4] and the NECO Study Report was included in the testimony.

In 2017, the NECO Subcommittee changed its focus to the transmission system south of Greeley. The objectives are similar to the North of Greeley studies, and are to reliably replace the existing 44 kV system, increase the ability to accommodate future load growth, allow for beneficial resource development, and align with other transmission projects and plans in the area.

In 2017, the NECO Subcommittee met on:

- March 8, 2017
- July 14, 2017
- August 18, 2017
- September 27, 2017

The subcommittee has performed some studies to evaluate the present load-serving and generation interconnection capabilities. A preliminary set of alternatives to meet the objectives were developed at one of the first meetings. The subcommittee will continue to meet in 2018 with the goal of developing a recommended alternative to move forward with.
Materials from these meetings can be found on the NECO page of the CCPG website:

http://regplanning.westconnect.com/ccpg_neco_sc.htm

CCPG Rush Creek Task Force Stakeholder Input Process

Public Service received approval from the CPUC to build, own, and operate the Rush Creek Project, which consists of 600 MW of wind generation in eastern Colorado. The project includes the 83-mile Rush Creek-Missile Site 345 kV line to interconnect the wind generation. The CCPG Rush Creek Task Force ("RCTF") was created in response

[4] Proceeding 17A-0146E.

to the Rush Creek Settlement Agreement (“Settlement Agreement”) in the CPUC proceeding for the Rush Creek Project. The Settlement Agreement includes the following statement:

“The Company (“PSCo”) will take a leadership role in a Colorado Coordinated Planning Group (“CCPG”) Task Force (or Sub-Group) to analyze the costs and benefits of alternative proposals to potentially integrate the Gen-tie as a network transmission facility. The alternatives to be studied must be reviewed and determined to be a reasonable networking alternative to be evaluated by the CCPG Task Force. The Company commits that it will offer staff and computing resources from its Transmission Planning group, will use its best efforts to publish the CCPG report after stakeholder comment no later than 12 months after the settlement agreement is filed with the Commission.”

As a result of the request, in March 2017, the RCTF finalized a study scope and began evaluating alternatives to network the Gen-tie. The RCTF performed technical analysis of fourteen alternatives to potentially integrate the Gen-tie as a network facility. Several other alternatives were considered, but not included in the technical analysis. The costs of the alternatives for this analysis were based on indicative capital construction costs. The benefits of the alternatives were measured primarily in terms of how much additional generation a particular alternative could accommodate. Other costs and benefits may be achieved, but were not the focus of this analysis. The RCTF provided an open stakeholder forum to analyze the costs and benefits of alternative proposals to potentially integrate the Rush Creek 345 kV Gen-tie as a network transmission facility.

The RCTF held nine regularly scheduled monthly meetings from December 2016 through August 2017 to discuss study assumptions, study methodology, potential alternatives, cost estimates, and benefits and draft a final study report. The RCTF consisted of 48 stakeholders and approximately half regularly attended the monthly meetings held on:

- December 1, 2016
- January 24, 2017
- February 22, 2017
- March 29, 2017

- April 27, 2017
- May 25, 2017
- June 22, 2017
- August 9, 2017
- August 29, 2017

Prior to the December 2016 kickoff meeting, two stakeholders submitted transmission alternative suggestions using the CCPG Comment Form. These forms are provided in Appendix K. The RCTF addressed the stakeholder comments during the course of the study process, which was documented in meeting notes.

The RCTF stakeholders evaluated numerous alternative proposals and agreed to perform technical analysis of the following fourteen alternatives:

1. New 345 kV line from Rush Creek II to Burlington Substation.
2. New 345 kV line from Rush Creek I to Big Sandy Substation.
3. New 345 kV line from Rush Creek II to Limon Wind Gen Substation.
4. Second Missile Site to Rush Creek II 345 kV line, looping into Rush Creek I.
5. New 345 kV lines from Rush Creek II to Burlington Substation and from Rush Creek I to Big Sandy Substation.
    a. Alt 5 plus a new 345 kV line from Big Sandy to Story Substation.
    b. Alt 5a plus a new 345 kV line from Rush Creek I to Daniels Park Substation.
    c. New 345 kV lines from Rush Creek II to Burlington Substation, Rush Creek II to Big Sandy Substation, and Big Sandy to Story Substation.
6. New 345 kV lines from Rush Creek II to Burlington Substation and from Rush Creek I to Limon Gen Substation.
7. New 345 kV lines from Rush Creek II to Burlington Substation and from Rush Creek II to Limon Wind Gen Substation.
8. New 345 kV lines from Rush Creek I to Daniels Park 345 kV Substation and Rush Creek II to Burlington Substation.
    a. New 345 kV lines from Rush Creek I to a new switching station south of Daniels Park and Rush Creek II to Burlington Substation.
9. New 345 kV lines from Rush Creek I to Daniels Park 345 kV Substation and from Rush Creek I to Rush Creek II.
    a. Alt 9 plus loop the Midway-Waterton 345 kV line into Daniels Park Substation.

The RCTF released a first draft of the Rush Creek Task Force Study Report for stakeholder review on August 3, 2017 and held two subsequent meetings to discuss the

report. A final study report was completed after stakeholder comment September 2017. The final report includes stakeholder comments in Appendix B of that report and can be accessed from the CCPG – Rush Creek Task Force website shown below.

All RCTF supporting documentation including meeting agendas, presentations, notes, and the final study report are accessible from the CCPG – Rush Creek Task Force website located at: http://regplanning.westconnect.com/ccpg_rush_creek_tf.htm.

Stakeholder Input

Prior to forming the RCTF, CCPG comment forms were received by two stakeholders: the OCC, and Dietze and Davis. The comment forms are included in Appendix K. Since the comments submitted were to evaluate specific alternatives to integrate the Gen-tie, they were addressed in the course of RCTF studies. On April 26, 2017, the RCTF received a written request from Interwest Energy Alliance to address "Benefits of integration as part of the network transmission system". That request is included in Appendix K. The RCTF final report addressed potential benefits in the final report.

RUSH CREEK FOLLOW UP

The Rush Creek Settlement Agreement also required Public Service to initiate conversations with other transmission providers and stakeholders concerning the identified alternatives from the final Rush Creek Task Force Study Report. Specifically, the Settlement Agreement states:

> *"If the CCPG Task Force studies identify benefits associated with alternatives that integrate the Rush Creek Gen-tie line as a network facility, and which alternatives address identified present or future needs, Public Service will initiate conversations with other transmission providers and stakeholders (as defined in Rule 3627) concerning the identified alternatives. Such discussions will include, but are not limited to, the interest in constructing an identified alternative, potential financial responsibilities associated with the alternative, the timing of a CPCN application to the extent a CPCN is required, and the proposed in-service date for the alternative. Notwithstanding the results of the CCPG Task Force studies or the outcome of such discussions, Public Service will include in its February 2018 filing under Rule 3627 the CCPG Task Force study results, a*

summary of the subsequent discussions, and a presentation of Public Service's position with respect to moving forward with any of the identified alternatives."

Public Service scheduled a meeting with interested stakeholders on October 10, 2017. The meeting invitation, agenda and PowerPoint presentation are provided in Appendix K. The agenda included a summary of the RCTF study and report and a discussion with stakeholders of the present and future needs, and solicitation of interest in constructing and/or financing any alternative. At the beginning of the meeting, Public Service stated that the Company did not see any present or future needs for moving forward at this time with any of the alternatives to integrate the Gen-tie as a network facility. However, the Company stated that the meeting was being held to provide the opportunity for stakeholders to express their interests and concerns. A summary of the comments received and Company responses follow.

1. 2016 Public Service ERP: some stakeholders stated that bids received to meet the ERP resource need may indicate that there is a present or future need to network the Gen-tie. They felt that is was premature for the Company to say that there is no future need at this point. The Company responded by showing the specific resource needs as stated in the 2016 ERP and the proposed Colorado Energy Plan ("CEP"). Public Service pointed out that the transmission system could handle a significant amount of new generation without networking the Gen-tie.
2. Benefit Analysis: Some stakeholders stated that more benefit analysis should have taken placed in the RCTF. The benefits metrics that are used by the Southwest Power Pool ("SPP") were specifically mentioned. The Company pointed out that the RCTF was clear that benefits would focus on injection capability. At the meeting, the Company noted that since Public Service is not in an organized market at this time, other benefits metrics may not apply. More importantly, entities such as SPP do not evaluate alternatives unless a specific need has been identified and agreed to. In this case, the Company has not identified a specific need.

3. Implementation: There was a comment that the Company should plan and construct transmission in advance of a present need. The Company responded that there is a considerable risk with moving forward with a project, and a particular need does not materialize. Additionally, the Company noted that obtaining regulatory approval is questionable to construct a transmission project without evidence of a present need. While the RCTF has developed potential planning alternatives that may be implemented when the timing is right, the Company has not identified such a need at this time.

In summary, Public Service does not see a present or future need to compel it to move forward with any alternative to network the Rush Creek Gen-tie at this time. Although some stakeholders want Public Service to pursue an alternative, no parties have expressed an interest in constructing or financing any alternative.

VII. 10-Year Transmission Plan Compliance Requirements

A. Efficient Utilization on a Best-Cost Basis: Rule 3627(b)(I)

Each Company endeavors to conduct transmission planning with the goal of achieving best-cost solutions that balance numerous factors and result in optimal transmission projects. Rule 3627(b)(I) defines “best-cost” as “balancing cost, risk and uncertainty and includes proper consideration of societal and environmental concerns, operational and maintenance requirements, consistency with short-term and long-term planning opportunities, and initial construction cost."

The Companies recognize that a project that is financially impractical will experience difficulty in gaining support from the Commission, customers, shareholders in the case of Black Hills and Public Service, and members in the case of Tri-State. However, cost is not the only consideration when selecting and developing transmission projects. The Companies take a number of factors into consideration when planning the long-term build-out of the transmission system, including but not limited to the following:

- Load projections
- Project partnership opportunities
- Regional congestion
- Transportation corridors
- Transmission corridors
- City and county zoning
- Geographic features
- Societal and environmental impacts
- Operational and maintenance requirements
- Consistency with short term and long term planning opportunities
- Initial construction cost

The impact each factor has on a particular project varies based on the nature of the project. Nevertheless, each factor is considered to some extent during the planning stage.

Take the fairly broad environmental and societal concerns factor, for example. As its name implies, this factor considers how a project relates to the natural environment and

the public in general – both positively and negatively. In the context of transmission planning, this usually means:

- The negative effects to the local environment from constructing a new transmission line or substation.
- The net positive impact to the environment of constructing a particular new transmission facility as an alternative to a different project over a more sensitive area.
- The positive impact to the environment of utilizing existing transmission corridors or upgrading existing facilities rather than constructing new ones.
- The positive impact to the environment and society if a project gives transmission customers access to a more diverse mix of generation resources, which can potentially reduce overall emissions and energy costs.
- The positive impacts to society by providing stable and reliable electricity. This is particularly important in rural areas where a single transmission outage has the potential to de-electrify entire regions.

For example, a planner may determine, by inspection, that a certain alternative is not practical because it would require a new transmission line over sensitive or exceptionally rugged terrain. This occurred in the CCPG San Luis Valley Subcommittee. The Subcommittee was tasked with evaluating the performance of alternatives to improve several deficiencies in the San Luis Valley transmission system, the biggest deficiency being that a single line outage can cause widespread outages to customers served by Public Service and Tri-State in Saguache, Mineral, Rio Grande, Alamosa, Costilla, and Conejos counties. One proposed alternative was to add a second 230 kV line to the San Luis Valley from either Montrose or Pagosa Springs. Electrically speaking, a new transmission line from either of these sources would likely improve reliability in the San Luis Valley. However, the Subcommittee declined to analyze them in part because these alternatives would require the construction of new transmission lines across rugged mountainous regions. Given the potential costs, environmental impacts, and permitting and construction challenges, it was decided these alternatives did not justify the effort required to model and analyze them. More information on the work of the CCPG San Luis Valley Subcommittee can be found in the Colorado Coordinated Planning Group San Luis Valley Subcommittee report in Appendix M.

Operational and maintenance concerns are also considered in the planning process. These factors include things such as:

- Spare equipment strategies, particularly for equipment that if failed, would take longer than 6 months to replace.
- The ability of the system to allow maintenance outages of lines and transformers.
- The capability of the system to accommodate required and increased demands on limited transmission path transfer limits.
- The capacity of the system to allow generators to output their full energy without operating restrictions or operating procedures (congestion).
- Increasing system robustness so that the use of load shedding, special protection, and cross tripping schemes can be minimized.

For example, operational concerns were considered by the CCPG Western Slope Subcommittee in their 2014 *Western Colorado Transmission Study Report.* This study focused on the capacity of the western Colorado transmission system to accommodate present and future power transfers. The Subcommittee proposed and evaluated numerous potential transmission projects to facilitate higher transfer limits on TOT 2A, which is a limited transmission path. More information on this study can be found in the Western Colorado Transmission Study Report included in Appendix M.

Tri-State's Lamar-Burlington 230 kV project study provides an example of how planners consider generation congestion. Presently, there is more generation connected in the Burlington region than the existing system can accommodate, including renewable generation. The study determined that a new 230 kV line between Lamar and Burlington would relieve this congestion, provide environmental and societal benefits by accommodating renewable generation, and mitigate other issues, as seen in the Burlington-Lamar 345/230 kV Impact and 2013 Post TPL Assessment Study in Appendix M.

Good transmission planning requires that alternatives be evaluated in the context of short-term and long-term planning opportunities as well. In planning vernacular, this means considering:

- The relative ability of transmission alternatives to serve more loads, whether it is in the near-term or long-term planning horizon;
- The capability of new transmission alternatives to allow the injection and export of new generation resources; and
- The manner in which transmission alternatives align with longer term transmission strategies.

The CCPG San Luis Valley Subcommittee explicitly considered the first two factors in the 2015 San Luis Valley Study. Voltage Stability ("P-V") analysis was performed for each studied alternative to compare their relative strength. This type of analysis is a common way to consider the relative ability of various transmission alternatives to serve future loads. The San Luis Valley Study also looked at the ability of each alternative to export new generation resources out of the San Luis Valley transmission system.

Tri-State's aforementioned Lamar-Burlington 230 kV project is a good example of planners considering how transmission alternatives are designed to align with longer term transmission strategies. In its CPCN testimony, Tri-State discussed how the Lamar-Burlington 230 kV project was an important first step to ultimately meet the objectives of larger, conceptual transmission projects in eastern Colorado. This can be seen in the Burlington-Lamar 345/230 kV Impact and 2013 Post TPL Assessment Study in Appendix M.

In general, a primary method of identifying and addressing many of the planning factors is through stakeholder participation in the planning process. Since planning is one of the initial stages of transmission project development, a preliminary evaluation of the aforementioned factors is typically performed as a screening process, with progressively more meaningful, in-depth evaluation occurring through the siting, permitting, and construction stages of development.

Adherence to best-cost principles is formally reflected by each Company in its internal policies. For example, Tri-State policy requires careful consideration of:

- Cost comparison of alternatives for providing capacity to serve load
- The use of existing delivery points and sub-transmission system
- Early construction of other delivery points planned by the member and/or neighboring utilities
- Alternate locations for the new delivery point
- Possible augmentation of the distribution system in lieu of transmission facility construction

The Companies perform an economic feasibility study of the best alternatives using the "single-entity concept," taking into consideration the total costs to the lead Company, as well as other affected utilities or member cooperatives. During the economic study, the following criteria are evaluated:

- Electrical performance of existing and proposed facilities, to include voltage drop, power-flow, and losses
- Estimated capital and annual costs
- Wheeling costs
- Reliability
- Environmental considerations
- Coordination with other transmission providers' long-range transmission plans

In addition, the Companies incorporate "best cost" considerations through their interactions with various federal, state, and local regulatory bodies. Among other, requirements, FERC has imposed planning requirements on utilities through its Order No. 890 and Order No. 1000 both of which include considerations consistent with Rule 3627’s “best cost” approach. These FERC requirements are discussed further below.

All of the Companies participate in Commission dockets and initiatives, spending significant time and resources for Notices of Proposed Rulemaking, outreach efforts, meetings with Commission Staff and actively participating in initiatives in which the

Commission has expressed interest. In addition, the Companies participate with Commission Staff in the development of the conceptual long-range plans for Colorado's electric transmission infrastructure. The Companies individually meet with representatives of the Colorado Energy Office ("CEO") and take into consideration CEO's suggestions. The Companies also meet with local governmental officials. These meetings transcend simple permitting requests, and consider factors such as the economic development aspirations of the communities, cultural concerns of communities, and the environmental aspects of transmission infrastructure expansion contemplated in various regions.

B. Reliability Criteria: Rule 3627(b)(II)

The Energy Policy Act of 2005 ("EPAct") amended the Federal Power Act ("FPA") to create mandatory electric reliability standards for the U.S. bulk power system. In compliance with these federal laws, FERC certified NERC as the electric reliability organization responsible for developing and enforcing the mandatory reliability standards authorized by the EPAct. NERC also utilizes delegation agreements with regional reliability organizations, such as WECC. Various mandatory reliability standards relating to bulk power system planning, operations, and maintenance have been implemented by NERC and WECC as a result of the EPAct with the potential for fines of up to $1 million per day for serious violations that could impact the integrity of the bulk power system.

The NERC Reliability Standards can be found at NERC's website.
www.nerc.com/pa/stand/Pages/default.aspx

The WECC TPL Standards can be found at WECC's website.
www.wecc.biz/Standards/Pages/Default.aspx

Each of the Companies take NERC and WECC compliance extremely seriously, and stringently adhere to all applicable standards and criteria. Additional information concerning each Company's reliability compliance efforts is provided below.

1. *Black Hills Reliability Criteria*

On top of NERC and WECC requirements, the following additional guidelines are utilized in the planning process for determining acceptable levels of service for the Black Hills service territory:

- Transmission line loadings should not exceed 100 percent of continuous seasonal rating or the established equipment or operating limits.
- Transformer loading under system intact conditions should not exceed 100 percent of the normal rating.
- Transformer loading under contingency conditions should not exceed 100 percent of the emergency rating.
- Transmission bus voltage levels during normal conditions will be maintained between 0.95 p.u. and 1.05 p.u. of nominal system voltage.
- Transmission bus voltages during contingency conditions will be maintained between 0.90 p.u. and 1.1 p.u. of nominal system voltage.
- Following a disturbance, all machines in the system shall remain in synchronism as demonstrated by their relative rotor angles for all Category P1 contingencies.
- A generator that pulls out of synchronism in the simulation shall not result in the tripping of any additional transmission facilities.
- System stability is evaluated based on the damping of relative rotor angles and the damping of the voltage magnitude swings. The following criteria is applied to the observed generator angle oscillations:
    - The generator angle should always be positively damped
    - The successive peak ratio (“SPPR”) should be less than 0.95, defined by

      SPPR = (Successive swing amplitude / Previous swing amplitude)

    - The damping factor (“DF”) should be at least 5%, defined by:

      % Damping factor = [(1-SPPR)*100]

Additional details on the reliability criteria observed by Black Hills are provided on pages 15-18 of the Black Hills OATT Attachment K Methodology, Criteria, and Process Business Practices document, available in Appendix L.

2. *Tri-State Reliability Criteria*

In addition to complying with NERC and WECC standards and criteria, Tri-State observes its own set of internal criteria for planning studies. Tri-State performs an annual assessment of its regional interconnected transmission system elements utilizing simulation modeling cases created by WECC members. This annual assessment takes into account Tri-State's members in four states, with associated projects located in Colorado included in this plan.

The modeling cases selected represent projected loads and transmission system topology for the year one through five horizon and the year six through ten horizon. These cases are selected to demonstrate system performance covering a range of forecasted demand levels and the most critical system conditions and study years. This analysis examines heavy and light loading scenarios, typically in cases modeling year one, year five, and year ten, unless other factors, such as known major system changes, dictate selection of another year. Cases created by WECC ensure that all projected firm transfers and established normal (pre-contingency) operating procedures are modeled, as well as existing and planned reactive power resources.

The transmission system is analyzed considering the planned projects for each utility in the study area. This assessment includes one or more current or past studies, which together address the entire Tri-State area of service.

Additional information concerning Tri-State's reliability criteria is available in its Engineering Standards Bulletin and is updated periodically. The most current version at the time of this filing can be found in Appendix M.

3. *Public Service Reliability Criteria*

In addition to fulfilling NERC and WECC standards and criteria, Public Service observes internal company criteria for planning studies. The most recent internal criteria can be found in Appendix N.

C. Legal and Regulatory Requirements: Rule 3627(b)(III)

Per Rule 3627(b)(III), "Each ten year transmission plan shall demonstrate compliance with…[a]ll legal and regulatory requirements, including renewable energy portfolio standards and resource adequacy requirements." The following sections provide information concerning each Company's compliance with such legal and regulatory requirements.

1. Black Hills Legal Requirements

Black Hills' portion of the 2018 Plan complies with all applicable NERC and WECC reliability standards, as well as other applicable legal and regulatory requirements, including the Colorado RES. For additional information on resource adequacy requirements, and resource requirements meeting the RES, please refer to pertinent proceedings and Commission decisions, as follows:

- Resource Planning, ERP - Phase I 2016 and Phase II 2017

  Black Hills' 2016 ERP is docketed at the Colorado Public Utilities Commission in Proceeding No. 16A-0436E. The Company's ERP application was filed on June 3, 2016 pursuant to Commission rules and the RES codified at C.R.S. § 40-24-124.

  The ERP covers a Planning Period of 25 years from January 2016 through December 2040, and a Resource Acquisition Period of 7 years from January 2016 through December 2022. The Planning Period pertains to ERP Phase I, a Commission determination of resource need. The Resource Acquisition Period pertains to ERP Phase II, a competitive solicitation for resource acquisition.

On January 17, 2017, Recommended Decision No. R17-0039 was entered for Phase I and became a decision of the Commission. The decision adopted a settlement agreement filed on November 10, 2016. The settlement agreement modified certain terms of the Company's ERP application. Specifically, the settlement agreement approved, in pertinent part, a resource need of up to 60 MW for commercial operation in 2019 from RES-eligible energy resources. This will enable the Company to comply with a 30% RES requirement in 2020. Stand-alone REC bids, to fulfill the 60 MW resource need, are not allowed under the settlement agreement. The settlement agreement approved evaluation criteria for utility-owned resource bids. Finally, the settlement agreement stipulated a timeline for Phase II to ensure that federal Production Tax Credits can be advantaged for eligible bids.

- RES Compliance Plan, 2018-2021

  The settlement agreement in ERP Proceeding No. 16A-0436E approved acquisition of on-site solar and community solar garden resources for RES compliance. The on-site solar program capacity is established at 1,500 kW per year for the compliance period 2018-2021. The settlement agreement stipulated categories for system sizes and incentive levels. Additionally, the settlement agreement adopted two RFP offerings by the Company for community solar gardens ("CSG"): 100% low-income subscribers and open-subscribers. The settlement agreement stipulated 0 kW as the minimum purchase amount and 2,500 kW as the maximum purchase amount for newly-installed CSG generation each compliance year, 2018-2021.

2. Tri-State Legal Requirements

Tri-State's 2018 Plan complies with all applicable NERC and WECC reliability standards, as well as other applicable legal and regulatory requirements including Company and member compliance with the Colorado RES.

For the period 2015 through 2019, the Colorado RES requires that 6 percent of Tri-State's Member Systems' retail energy sales be served by renewable generation, growing to 20 percent in 2020 and beyond. In addition, as a qualifying wholesale utility, the Colorado RES requires Tri-State to generate or cause to be generated at least 20% of the energy it provides to its Colorado Member Systems at wholesale from eligible energy resources in the year 2020 and thereafter. As the wholesale power provider for its Member Systems, Tri-State's 2018 Plan is developed to ensure that the necessary transmission system capabilities will be in place to meet both its Colorado Members Systems' and its own RES requirements.

For additional information on resource adequacy requirements and resource requirements to meet the RES, please refer to Tri-State's Integrated Resource Plan/Electric Resource Plan and Electric Resource Plan Annual Progress Reports available in Appendix M.

As discussed previously, Tri-State may be subject to federal and state regulations related to carbon emission reductions from existing power plants. While no such regulations have been promulgated as of the date of this 10-Year Plan, Tri-State anticipates that such regulations may be promulgated within the next two years and, if so, will address them in the next 10-Year Transmission Plan. Tri-State also notes that, since it operates an interconnected, interstate transmission system, its transmission system may be impacted as a result of federal compliance and carbon emission reduction plans enacted in other states in which Tri-State operates.

3. Public Service Legal Requirements

Public Service's 2018 Plan complies with all applicable NERC and WECC reliability standards, as well as other applicable legal and regulatory requirements including the Colorado RES requirements. Information on Public Service compliance with RES requirements is available at:
https://www.xcelenergy.com/company/rates_and_regulations/filings.

Additional information on Public Service resource adequacy and compliance with Commission rules related to ERPs is available at:
https://www.xcelenergy.com/company/rates_and_regulations/resource_plans

D. Opportunities for Meaningful Participation: FERC Order No. 890

In addition to the CCPG planning processes, each of the Companies has its own FERC Order No. 890 stakeholder process as described below. For additional information on stakeholder involvement pertinent to Rule 3627, please refer to Section VI.

1. *Black Hills Participation Strategy*

For Black Hills, the FERC Order No. 890 Stakeholder Process is included in its Attachment K to its Open Access Transmission Tariff ("OATT"), which is included in Appendix L of this document. Additional information concerning Black Hills' FERC Order No. 890 processes can also be found in Appendix L.

2. *Tri-State Participation Strategy*

Attachment L to Tri-State's OATT demonstrates Tri-State's transmission planning processes consistency with FERC Order No. 890 planning principles. As discussed previously in this 2018 Plan, all projects included herein have been identified and developed through Tri-State's transmission planning process.

Attachment L to Tri-State's OATT is available on Tri-State's OASIS, and can be updated periodically. The most current version at the time of Attachment L is located in Appendix M.

3. *Public Service Participation Strategy*

For Public Service, the FERC Order No. 890 stakeholder process is included in the Xcel Energy Joint OATT Attachment R, available at the following website:
http://www.oatioasis.com/PSCO/PSCOdocs/PSC-PRO-PSCo_Attachment_R.pdf

Additional information concerning the Public Service FERC Order No. 890 processes can be found at:

http://www.oatioasis.com/psco/index.html under "FERC 890 Postings".

E. Coordination Among Transmission Providers: FERC Order No. 1000

In July, 2011, FERC issued a final rule related to transmission planning and cost allocation, FERC *Order 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities* ("Order 1000"). This order builds on planning principles already established in FERC Order No. 890, as previously discussed. FERC Order No. 1000 requires that transmission owning and operating public utilities:

1) Participate in a regional transmission planning process that produces a regional transmission plan.
2) Amend their OATT to describe procedures that provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes.
3) Remove from Commission-approved tariffs and agreements a federal right of first refusal for certain new transmission facilities.
4) Improve coordination between neighboring transmission planning regions for interregional transmission facilities.
5) Participate in a regional transmission planning process that has a regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation.
6) Participate in a regional transmission planning process that has an interregional cost allocation method for the cost of certain new transmission facilities that are located in two or more neighboring transmission planning regions and are jointly evaluated by the regions.

WestConnect is one of four planning "regions"[5] within WECC established for regional transmission planning to comply with Order 1000. Public Service and Black Hills have

[5] The other three are Columbia Grid, Northern Tier Transmission Group, and the California Independent System Operator.

designated WestConnect as their Order 1000 compliant planning regions. Tri-State has joined WestConnect as a coordinating transmission owner, which means it is not subject to all of the requirements under Order 1000 such as accepting binding cost allocation for regional transmission projects. The WestConnect planning process is described in Black Hills' and Public Service's OATTs (Attachment K and R respectively; links are provided above) as well in documentation found on the WestConnect website (http://www.westconnect.com/). The WestConnect website also houses information and announcements for many public planning meetings. WestConnect accepts stakeholder input throughout the planning process.

WestConnect develops a regionally coordinated transmission plan that begins with the determination of regional reliability, economic and public policy needs. The more cost effective or efficient solutions to meet identified regional needs are included in the regional plan. These regional projects may be new projects in addition to the projects developed through the local or sub-regional planning processes or may replace local projects in some instances. If WestConnect determines Colorado utilities benefit from a regional project, then those Colorado utilities may be responsible for a portion of the cost of the regional project.

Additionally, WestConnect coordinates with the other western Order 1000 planning regions. This coordination is also described in Black Hills' and Public Service's planning attachments to their respective OATTs.

VIII.10-Year Transmission Plan Supporting Documentation

A. Methodology, Criteria, & Assumptions

1. *Facility Ratings (FAC-008-3)*

NERC Reliability Standard FAC-008-3 requires that transmission and generation owners document the methodology used to develop ratings of their equipment. The standard requires that the transmission or generation owner supply its methodology to specific NERC registered entities upon request. FAC-008-3 also requires transmission and generation owners to establish facility ratings per the methodology established through FAC-008-3. Each transmission and generation owner has documented ratings for each of its facilities. The standard requires the transmission or generation owner to supply its facility ratings to specific NERC registered entities (i.e. associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s)) upon request. These documents are not publicly available and are not required to be per NERC standards. NERC Reliability Standard MOD-032-1 requires applicable entities to provide equipment characteristics, including established facility ratings, to NERC and WECC according to established reporting requirements. This is accomplished through the WECC Base Case Compilation Schedule as prescribed by the Data Preparation Procedural Manual.

a. Black Hills Ratings

Documentation of Black Hills' FAC-008-3 methodology is available in Appendix L.

b. Tri-State Ratings

Documentation of Tri-State's Facility Rating's methodology is available in its Engineering Standards Bulletin. The most current version of Tri-State's Engineering Standard's Bulletin at the time of this filing can be found in Appendix M.

c. Public Service Ratings

Documentation of Public Service FAC-008-003 methodology can be found in Appendix N.

2. *Transmission Base Case Data: Power Flow, Stability, Short Circuit*

The Companies utilize transmission system power flow and transient dynamics modeling data prepared by WECC. Through its Annual Study Program, WECC facilitates the preparation of at least ten models per year. The models represent a variety of system conditions out to a 10-Year planning horizon. WECC's 10-Year Regional Transmission Plan is an Interconnection-wide perspective on: 1) expected future transmission and generation in the Western Interconnection, 2) what transmission capacity may be needed under a variety of futures, and 3) other related insights.

WECC members participate in the data preparation process for the models and Public Service coordinates the data for the Rocky Mountain region. Prior to being used for planning studies, the models are reviewed and adjusted to reflect the most current and accurate system elements, ratings, and operating conditions for the region to be studied. Short circuit data is coordinated between neighboring TPs as needed and periodically coordinated at the CCPG level.

Instructions for obtaining access to WECC base cases are as follows:

a. An organization requesting WECC base case(s) must either be a WECC member or they must execute the “Nonmember Confidentiality Agreement for WECC Data.”

b. Non-members may obtain the confidentiality agreement from WECC by requesting the agreement from a WECC Stakeholder Services representative.

The submission must include a statement from the organization explaining why they have a legitimate business need for the WECC base case(s).

B. Load Modeling

Pursuant to each Company's OATT, network customers are required to submit 10-Year projected network loads and network resources by October 1 of each year. This information is then compiled with existing data and information to provide a basis for identification of the minimum transmission system enhancements required to ensure that a sufficiently robust transmission system is in place to meet all network customer requirements under all scenarios.

1. *Forecasts*

The Companies rely on the most recent and accurate load forecasts when developing system planning models. General load forecast assumptions are posted on each transmission provider's Company or OASIS site.

a. Black Hills Forecasts

In 2016, Black Hills filed with the Commission its latest ERP, which included details on expected customer growth based on load forecast information submitted annually by network customers. The ERP, in conjunction with the network customer forecast updates, is used in the development of Load and Resource ("L&R") reports submitted to WECC on an annual basis. Once the L&R report is developed, this forecast is disaggregated to the respective transmission system load buses. There are two types of load buses: (1) a load bus where the load does not change over time (e.g. a single large industrial load bus); and (2) a load bus where the load changes over time (e.g. a residential load). Black Hills uses its knowledge of load characteristics along with historical loading observations to estimate the individual load bus data in time. The load bus forecasts are summed and compared to the WECC L&R report aggregate load forecast. If the two forecasts do not match, the variable bus load forecasts are adjusted until the two forecasts match. Through this procedure the WECC L&R reports, including the assumptions in the latest ERP, are reflected in the transmission planning models used within the WECC footprint. Deviations from the ERP load forecast are commonplace in transmission studies depending on the

purpose of the planning analysis being performed and the study scenario of interest. The load assumptions included in the planning model are typically specified within each planning study report for reference.

Details related to Black Hills' load forecast can be found beginning on page 21 of Black Hills' 2016 ERP in Colo. Consolidated Proceeding No. 16A-0436E (Attachment LS-1, Section 4). Section 4 of Attachment LS-1 is included in Appendix L of this report for reference.

b. Tri-State Forecasts

General load forecast information is available on Tri-State's OASIS by clicking on "ATC Information" and then "Load Forecast Descriptive Statement". The Load Forecast Descriptive Statement available at the time of this filing is located in Appendix M.

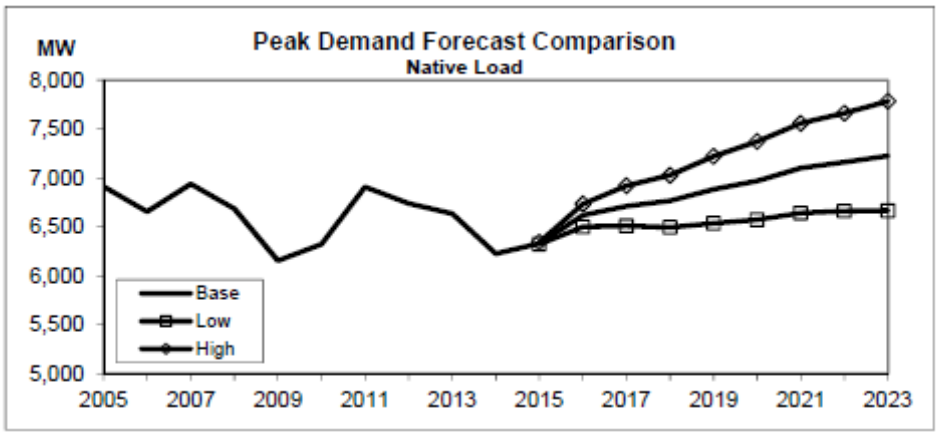
Tri-State prepares load forecasts on a system-wide and regional basis with regional forecasts used for resource planning purposes. Tri-State receives load forecasts from its network customers by October 1 of each year. These loads are modeled as required for inclusion in the planning models developed in conjunction with neighboring entities.

Tri-State's most recent transmission plans utilize 2016 load forecast data. Base forecast data for these plans is available in Appendix A of Tri-State's ERP/APR, located in Appendix M.

c. Public Service Forecasts

Public Service provided its most recent public forecast information in its 2016 Electric Resource Plan (Volume 2). The following figure shows the base, high, and low forecasts of native load peak demand graphically.

Figure 8. Public Service Historic and Forecast Demand



In addition to native load forecasts, Public Service receives forecasts from its wholesale customers, which it incorporates into the overall forecast. Transmission planners allocate the loads on a substation-by-substation basis, based on historical trends. The entire 2016 Electric Resource Plan can be found at: https://www.xcelenergy.com/staticfiles/xe/PDF/Attachment%20AKJ-2.pdf.

The pertinent pages of Volume 2 are pages 2-24 through 2-25, and these are included in Appendix N.

2. Demand-Side Management

The effects of Demand-Side Management ("DSM") program savings are typically taken into account within the load forecasts described previously. Within the context of power system modeling, DSM is simply reflected in the power flow model as reduced load and therefore included in planning studies.

a. Black Hills DSM

Details related to the effects of DSM savings estimates on Black Hills' load forecast can be found in Section 2.7 on page 17 of the 2016 Black Hills ERP, Attachment LS-1, which is included in Appendix L of this document.

b. Tri-State DSM

Load forecasts provided for bulk electric transmission planning typically include existing DSM and other load-reducing programs, including member energy efficiency programs and local distributed generation. These programs are reflected in the power flow model as reduced load and are inherently included in studies. For transmission planning, load forecasts that contain load-reducing factors may be used for specific projects or for individual Tri-State members with DSM, local distributed generation, or other energy efficiency programs. For such cases, please refer to individual project planning studies. For Tri-State's system load forecast, these are described in Tri-State's 2014 ERP.

c. Public Service DSM

Public Service accounts for DSM through reduction in its load forecast based, in part, on the goals established by the Commission. DSM impacts are discussed in the load forecast section of Volume 2 of the Public Service Company 2016 Electric Resource Plan, which can be found in Appendix N.

C. Generation and Dispatch Assumptions

Generator and associated equipment models are typically included in the WECC Annual Study Program base cases as required by the Data Preparation Procedural Manual. The detail of generation models utilized within planning studies can vary depending on the nature of the study. For example, a Large Generator Interconnection study for a wind facility may explicitly model each individual wind turbine and the associated collector system to properly assess the low voltage ride through capabilities of the facility. That same facility may be modeled as a single equivalent wind turbine with an equivalence collector system within a long-range planning study where the performance

of individual wind turbines is not a concern. The scope of the technical study will influence the level of detail that is modeled.

1. *Black Hills Assumptions*

At the most basic level, Black Hills dispatches existing generation to meet the demand requirements of its system, including load and losses. The objective of a particular study often drives the individual generator dispatch levels. For example, a peak demand summer baseline scenario may consist of a majority of dispatchable baseload generation online and an appropriate mix of wind and solar PV to meet the demand requirements. An off-peak demand spring or fall scenario may have the available wind generation dispatched at its nameplate capacity with the dispatchable baseload generation and solar generation reduced to capture the impacts of that particular dispatch pattern. Existing power purchase agreements and other contractual arrangements may be reflected in certain study scenarios to further stress the transmission system. Black Hills may also include speculative generation (as identified in the current version of the Black Hills Colorado Electric Generation Interconnection Request Queue, included in Appendix L) in certain transmission studies as dictated by the study objective. Additionally, existing and/or conceptual generation may be dispatched beyond the demand requirements of the study case to facilitate a net export of energy from the study area.

A listing of existing and planned resources utilized in planning studies is typically included in each specific study report. For a list of existing Black Hills generation resources utilized in the planning models, please refer to Section 4, page 38 in Attachment LS-1 of the Black Hills 2016 ERP, which is located in Appendix L.

2. *Tri-State Assumptions*

Tri-State's transmission planning function receives generation assumptions from its network customers--Tri-State Power Marketing, Arkansas River Power Authority (“ARPA”), Municipal Electric Agency of Nebraska (“MEAN”) and Public Service Company of New Mexico (“PNM”)--annually by October 1. These generation

assumptions are utilized to ensure a sufficiently robust transmission system to meet network customers' needs over a 10-Year planning horizon.

Generation assumptions, including dispatch assumptions, and corresponding data for other transmission plans are project-specific. Therefore, the individual transmission studies should be referenced for generation assumptions relative to each such project.

3. *Public Service Assumptions*

Public Service transmission planning models reflect generation dispatch based on internal procedures that take into account production costs, maintenance schedules, and other factors. Procedures include:

- Modeling of generator planned outages with outage period of 6 months or more
- In general, if not needed to meet load requirements, high production cost generation plants are modeled out of service. If resources are needed, these units may be modeled
- Public Service combustion turbine generators are typically modeled at or near full output
- Public Service large coal-fired plants are typically modeled at or near full output. These units are considered “base loaded”, in that they usually operate around the clock if generation adjustments are necessary, these generators are generally adjusted last
- Hydro generation has net dependable seasonal ratings. Each seasonal rating reflects the average generation that can be continuously maintained over the duration of the daily peak period for the respective season. In winter, the daily period is approximately five hours long. All generators on-line should be producing reactive power (“MVARs”). Generator bus voltage scheduling may be necessary if the generating unit is acting in a condensing mode (consuming MVARs)

Renewable generation, including wind and solar are modeled based on Public Service Variable Energy Resource Dispatch Assumptions. System changes, load transfers, and other topology changes are also coordinated through CCPG.

D. Methodologies

1. *System Operating Limits (FAC-010)*

System Operating Limits ("SOL") is defined in NERC Reliability Standard FAC-010-3 as the responsibility of the Planning Authority ("PA") to ensure reliable planning of the Bulk Electric System. SOL is required to be established per FERC standards but is not required to be publicly available.

a. Black Hills SOL

Black Hills has defined both Operational Criteria, which are limits for typical every day/normal operations, and SOLs, which are limits that are of an emergency nature and must be acted upon promptly to ensure facility ratings are not exceeded. Black Hills' SOLs are communicated to the Loveland Reliability Control Center ("LRCC") Reliability Coordinator so that when an SOL is exceeded, the Reliability Coordinator will be aware of the concern and be able to provide assistance in ensuring the SOL violation is removed. Black Hills' SOLs are summarized below:

- BES Transmission Line SOLs are exceeded when the line rating is exceeded.
- BES Voltage SOLs are exceeded when the Emergency Voltage rating is exceeded. The Emergency Voltage is plus/minus 10% of the nominal voltage.
- BES transformer SOLs are exceeded when their loaded MVA is between 100% and 125% of the established FOA Rating for more than 30 minutes, OR, their loaded MVA exceeds 125% of the established FOA Rating for any period of time.

b. Tri-State SOL

Tri-State is not a PA and, therefore, uses the SOL methodology as defined by the applicable PA.

c. Public Service SOL

Public Service has one SOL for the TOT7, which is located north of the Denver metro area. SOLs are required to be established per FERC standards, but are not required to be publicly available. The TOT7 studies are conducted annually. The results of those studies are available upon request.

2. *Transfer Capabilities (MOD-001)*

Available Transmission System Capability Methodology is available and posted per NERC Standard MOD-001 at NERC's website.

a. Black Hills TTC

Black Hills utilizes the Rated System Path Methodology for determining Total Transfer Capability ("TTC") and Available Transfer Capability ("ATC") for all Posted Paths and in all ATC time horizons. The determination of TTC is based on the maximum flow of a path while meeting all reliability criteria for single initiating event outages. In the event that the path is flow-limited and a reliability limit cannot be reached, the transfer capability of the path is set to the thermal rating of the path. For further details on the calculation of transfer capability, refer to Black Hills' ATC Implementation Document ("ATCID") included in Appendix L.

b. Tri-State TTC

Tri-State's TTC path values for jointly owned paths that are interfaces identified and rated through WECC processes and OTC determinations are based upon the Rated System Path Methodology (NERC MOD-29-1). Tri-State has TTC allocations on WECC rated Paths 30 (TOT1A), 31 (TOT2A), 36 (TOT3), 39 (TOT5), 47 (SNMI), and 48 (NNMI). These paths are studied by the path operator with actual flow levels at the combined path ratings under simulated N-1 scenarios to ensure that the planning reliability criteria are being met. The path participants

have previously used studies and negotiations to determine the manner in which the TTC will be allocated to each of the participants.

For jointly owned paths that are not WECC-rated paths, the TPs determine the appropriate combined TTC and the allocation of it is based upon contractual capacity entitlements. This allocation is done outside of any WECC approval process since these are Tri-State TTC/ATCID minor paths that are not part of an interface and do not impact any major recognized WECC paths.

Tri-State utilizes TTC values based upon thermal facility ratings for all flow-limited paths that are owned solely by Tri-State. If the NERC MOD-029-1 requirement R2.1 simulation studies result in sufficient flow ability on a path segment to determine a reliability limit, then the TTC on the ATC path segment is set to the simulated flow corresponding to the reliability limit while at the same time satisfying all planning criteria.

In addition, Tri-State has created many extended ATC paths that are defined by a serial concatenation of rated path segments. The resulting TTC and ATC for each extended ATC path is based upon the lowest TTC and ATC of all the serial path segments included in each path definition.

The ATCID provides for the documentation of required information as specified in the NERC MOD Standards and the NAESB OASIS Standards regarding the calculation methodology and information sharing of ATC specific to this TP. The ATCID for Tri-State is available on Tri-State's OASIS, by clicking on "ATC Information" and then "ATCID Document".

The ATCID can be updated periodically and the most recent version of the ATCID at the time of this filing can be found in Appendix M.

c. Public Service TTC

Public Service's ATCID (MOD-001) is posted at the following link:

http://www.oatioasis.com/PSCO/ → ATC Information

3. *Capacity Benefit Margin (MOD-004)*

Capacity Benefit Margin ("CBM") methodology is available and posted per NERC Standard MOD-004.

a. Black Hills CBM

Black Hills does not implement CBM in the assessment of ATC. The Capacity Benefit Margin Implementation Document ("CBMID") for Black Hills is included in Appendix L.

b. Tri-State CBM

Based on FERC's allowance for TPs to not use CBM, Tri-State does not allow for the use of CBM and, as such, its value is set to zero (0) in the ATC equations for all paths posted by Tri-State. Furthermore, Tri-State's practice is to not maintain CBM. Tri-State will review its CBM practice, at least annually, and will post any changes to the OASIS as needed. The CBMID for Tri-State is available on Tri-State's OASIS, by clicking on "ATC Information" and then "Capacity Benefit Margin Statement (CBMID)".

The CBMID can be updated periodically, and the most recent version at the time of this filing can be found in Appendix M.

c. Public Service CBM

Public Service's CBMID is located at the following link:
http://www.oatioasis.com/PSCO/ → ATC Information

4. *Transmission Reliability Margin (MOD-008)*

NERC Standard MOD-008-1, Transmission Reliability Margin Calculation Methodology, requires that each Transmission Operator prepare and keep current a Transmission Reliability Margin Implementation Document ("TRMID").

a. Black Hills TRM

A copy of the current TRMID for Black Hills is located in Appendix L.

b. Tri-State TRM

The TRMID for Tri-State is available on Tri-State's OASIS, by clicking on "ATC Information" and then "TRMID Document".

The TRMID can be updated periodically, and the most recent version at the time of this filing is located in Appendix M.

c. Public Service TRM

The TRMID for Public Service is located at the following links:

http://www.oatioasis.com/PSCO/ → ATC Information

E. Status of Upgrades

Projects that constitute upgrades to existing transmission facilities are discussed in Section III of this Plan and the associated appendices.

F. Studies and Reports

Most of the Companies' study documentation can be found by starting at the sections of the WestConnect website that are dedicated to the CCPG:

http://www.westconnect.com/planning_ccpg.php

Additional Company-specific study and reporting resources are described below.

1. Black Hills Reporting

Public access to transmission market information, generator interconnection and transmission service requests, business practices, planning study reports and other topics related to the Black Hills transmission system is provided on Black Hills' OASIS at:

http://www.oatioasis.com/bhct

2. *Tri-State* Reporting

Planning studies and related reports for Tri-State transmission projects in Colorado are located at Tri-State's website by clicking on "Operations" and then "Transmission Planning".

3. Public Service Reporting

Planning studies and related reports for Public Service transmission projects in Colorado are located at the following links:

http://www.rmao.com/wtpp/psco_studies.html

http://www.oatioasis.com/psco/index.html

http://www.transmission.xcelenergy.com/Planning/Planning-for-Public-Service-Company-of-Colorado

G. In-Service Dates

Information concerning the expected in-service date for each utility's facilities identified in the 2018 Plan and the entities responsible for constructing and financing each facility is contained in Table 1, Section III and Appendices A-I.

H. Economic Studies

The purpose of economic planning studies is to identify significant and recurring congestion on the transmission system and/or address the integration of new resources and/or loads. Such studies may analyze any or all of the following: (i) the location and magnitude of the congestion, (ii) possible remedies for the elimination of the congestion, (iii) the associated costs of congestion, (iv) the costs associated with relieving

congestion through system enhancements (or other means), and, as appropriate (v) the economic impacts of integrating new resources and/or loads. Economic studies are generally described as being either “local” or “regional” in nature.

1. Black Hills Economic Study Policies

Black Hills conducts economic planning studies through the procedures outlined in its OATT Attachment K, which is included in Appendix L.

Black Hills will accept requests for economic studies on an annual basis. Information on making a request is available in the Attachment K Economic Study Request Form as shown in Appendix L. Upon receiving a valid request for an economic study, Black Hills, with input from its stakeholder committee, will classify the request as local, subregional or regional. Black Hills will engage the appropriate resources to study up to one economic study request that has been classified as local on a bi-annual basis. All economic study requests that have been classified as subregional or regional will be forwarded to the WECC for inclusion in the appropriate study program. Since the 2016 Rule 3627 filing, Black Hills has not received any economic study requests, nor has it performed any economic studies.

2. Tri-State Economic Study Policies

Western Interconnection-wide congestion and economic planning studies are conducted by WECC in an open stakeholder process that holds region-wide stakeholder meetings on a regular basis. The WECC planning process is posted on its website (see www.wecc.biz). Tri-State participates in the regional planning processes, as appropriate, to ensure data and assumptions are coordinated. Tri-State did not perform any economic studies this cycle nor were any requested by Tri-State stakeholders.

3. Public Service Economic Study Policies

Public Service facilitates priority local economic planning studies for its transmission system, pursuant to the procedures in its OATT Attachment R. Regional economic planning studies shall be performed by WECC, pursuant to procedures posted on

the WECC website. Public Service did not perform any economic studies this cycle nor were any requested by stakeholders.

2018 CPUC Rule 3627 Appendices

Appendix A: Colorado Transmission Maps

Appendix B: Denver-Metro Transmission Map

Appendix C: Black Hills Energy Transmission Map

Appendix D: Black Hills Energy Projects

Appendix E: Tri-State Generation and Transmission Association Projects

Appendix F: Public Service Company of Colorado Projects

Appendix G: Colorado Springs Utilities Projects

Appendix H: Platte River Power Authority Projects

Appendix I: Western Area Power Administration - RMR Projects

Appendix J: Stakeholder Process

Appendix K: CCPG Rush Creek Task Force

Appendix L: Black Hills Supporting Documents

Appendix M: Tri-State Supporting Documents

Appendix N: Public Service Company Supporting Documents