SUPPLEMENTAL JOINT REPORT

For the State of Colorado

To comply with

Rule 3627

of the

Colorado Public Utilities Commission

Rules Regulating Electric Utilities

June 8, 2020

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ACRONYMS AND ABBREVIATIONS

Acronym or Abbreviation	Term
AQCC	Air Quality Control Commission
BA	Balancing Authority
Basin Electric	Basin Electric Power Cooperative
BESS	Battery Energy Storage Systems
Black Hills	Black Hills Colorado Electric, LLC, d/b/a Black Hills Energy
CAISO	California Independent System Operator
CAISO WEIM	California Independent System Operator Western Energy Imbalance Market
CCPG	Colorado Coordinated Planning Group
CDPHE	Colorado Department of Public Health and Environment
CEII	Critical Energy Infrastructure Information
Commission or CPUC	Colorado Public Utilities Commission
Companies	Black Hills, Tri-State and Public Service
Company	Black Hills, Tri-State or Public Service
CRI	Community Resiliency Initiative
CSU	Colorado Springs Utilities
DER	Distributed Energy Resources
DG	Distributed Generation
EIA	Energy Information Administration
ERP	Electric Resource Plan
ERZ	Energy Resource Zone
EV	Electric Vehicle
FACTS	Flexible AC Transmission System
FERC	Federal Energy Regulatory Commission
HTLS	High-Temperature Low-Sag
JDA	Joint Dispatch Agreement
Joint Utilities	Public Service Company of Colorado, Black Hills Colorado Electric, LLC, and Tri-State Generation and Transmission Association, Inc.
kV	Kilovolt
LDC	Local Distribution Company
LMP	Local Marginal Pricing
Member Systems	Member Cooperatives and Public Power Districts
MW	Megawatts
MWTG	Mountain West Transmission Group

Acronym or Abbreviation	Term
NERC	North American Electric Reliability Corporation
OATT	Open Access Transmission Tariff
Order 1000	FERC Order No. 1000 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities
PRPA	Platte River Power Authority
Public Service	Public Service Company of Colorado
PV	Photovoltaic
REP	Responsible Energy Plan
RES	Renewable Energy Standard
RTO	Regional Transmission Organization
SB07-100	Colorado Senate Bill 07-100
SCED	Security Constrained Economic Dispatch
SPP	Southwest Power Pool
TEP	Transportation Electrification Plan
TP	Transmission Provider
TPL	Transmission Planning
Tri-State or TSGT	Tri-State Generation and Transmission Association, Inc.
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market
WEIS	Western Energy Imbalance Service
Western/WAPA	Western Area Power Administration (also WAPA)

I. Introduction

On February 3, 2020, Public Service Company of Colorado ("Public Service"), Black Hills Colorado Electric, LLC ("Black Hills"), and Tri-State Generation and Transmission Association, Inc. ("Tri-State" or "TSGT") (collectively referred to as the "Joint Utilities") jointly filed their biennial transmission plan (Joint Rule 3627 Transmission Plan), including a 10-Year Transmission Plan and 20-Year Conceptual Scenario Report in Proceeding No. 20M-0008E, as required by Rules 3625 to 3627 of the Colorado Public Utilities Commission ("Commission") Rules Regarding Electric Utilities (4 C.C.R. 723-3).

On April 1, 2020, the Commissioners deliberated on the Joint Rule 3627 Transmission Plan, and, pursuant to Decision No. C20-0213-I, directed the Joint Utilities to supplement their 10-Year Transmission Plan and 20-Year Conceptual Scenario Report with additional information, to be filed no later than June 8, 2020.

More specifically, the Commission directed the Joint Utilities to submit supplemental information in the following six general areas:

1) Clarification and further information regarding each utility's plan to meet requirements of §§ 40-2-125.5 and 25-7-105(1)(e)(VIII)(A), C.R.S.;
2) Discussion regarding whether and, if so, how each utility intends to address policy initiatives in Governor Jared Polis's "Roadmap to 100% Renewable Energy by 2040 and Bold Climate Action" (the "Governor's Roadmap");
3) Identification of anticipated organized market information as applied to each scenario and additional discussion regarding the result of the Joint Utilities' participation in potentially separate regional markets, including anticipated participation in energy imbalance market or day-ahead markets;
4) Information regarding the effects of technology advancements, specifically regarding energy storage capabilities over time;
5) Clarifications regarding Distributed Energy Resources (DER) and Distributed Generation (DG) terminology and concepts; and

6) Additional explanation regarding the elimination of the gas Local Distribution Company (LDC) as described in Public Service's Scenario No. 5 in the 20-Year Conceptual Scenario Report.

Since the Commission issued its Decision, the Joint Utilities have conferred and collaborated to develop this Supplemental Joint Rule 3627 Transmission Report ("Supplemental Joint Rule 3627 Report"). While the Joint Utilities have determined that there are a number of areas of alignment between each of the utilities, there are other areas that warrant more individualized responses to the Commission's six requests. For this reason, the Joint Utilities are submitting individual responses to some questions and combined responses to others. The Joint Utilities provide their responses to the Commission's six supplemental information requests in Section III below.

In its Decision, the Commission made two additional findings that the Joint Utilities address in this Supplemental Joint Rule 3627 Report. First, the Commission stated:

> The Joint 10-Year Transmission Plan and 20-Year Conceptual Scenario Report as supplemented with information required by this Decision shall include all models used and an explanation and copy of model outputs. Additionally, updates shall include discussion of the Basis of Plan, Identified Issues, and any Resource Requirements including Costs, Quality Metrics, and Stakeholder Register.

Second, the Commission stated:

> The Utilities are reminded to provide documentation verifying all information referenced in the Joint 10-Year Transmission Plan and 20-Year Conceptual Scenario Report, including supplemental information and, as appropriate, in an accessible format via a direct link to a utility or utility-maintained website consistent with Rule 4 CCR 3627(a)(III).

The Joint Utilities address these elements of the Commission's Decision in Sections III and IV below.

II. Supplemental Information Requested by Decision No. C20-0213-I

In this Section of their Supplemental Joint Rule 3627 Report, the Joint Utilities present their responses to each of the six categories of information requested by Commission Decision No. C20-0213-I.

A. Clarification and Further Information Regarding Each Utility's Plan to Meet the Requirements of §§ 40-2-125.5 and 25-7-105(1)(e)(VIII)(A), C.R.S

Through Decision C20-0213-I, the Commission directed the Joint Utilities to provide "supplemental information such that the Commission can review the Joint 10-Year Transmission Plan and 20-Year Conceptual Scenario Report with regard to recent statutory changes in § 40-2-125.5(3), C.R.S., that require reductions in carbon dioxide by 2030, and foreseeable public policy initiatives."[1] Each utility responds in turn, below.

i. Black Hills' Response

Section 40-2-125.5(3), C.R.S., has various clean energy targets for a "qualifying retail utility." A "qualifying retail utility" is a "retail utility providing electric service to more than five hundred thousand customers in this state or any other electric utility that opts in... ."[2] Black Hills does not meet this statutory definition of a "qualifying retail utility." In addition, Black Hills has not opted in to the statutory requirements, as permitted by § 40-2-125.5(3)(b), C.R.S. Accordingly, the clean energy targets of § 40-2-125.5(3), C.R.S., are not currently applicable to Black Hills.

Though the clean energy targets of § 40-2-125.5(3), C.R.S., do not apply to Black Hills, Black Hills is exploring whether its opting in to the statutory requirements would be in the best interests of customers. In order to make that determination, Black

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[1] Proceeding No. 20M-0008E, Decision No. C20-0213-I, (mailed date April 7, 2020), page 6, ¶16

[2] Section 40-2-125.5(2)(c)(I), C.R.S.

Hills will need to have clarity on the major components associated with Clean Energy Plan methodologies and targets. Specifically, Black Hills will need clarity on the type of sales (either wholesale or retail) that govern the 2005 baseline.[3] In addition, Black Hills will need clarity on the proper methodologies by which to assess historical, current, and future carbon dioxide emissions. These issues have not yet been decided. However, Black Hills understands that the Air Quality Control Commission (AQCC) of the Colorado Department of Public Health and Environment (CDPHE) will be providing the necessary clarity on these issues either through rulemaking proceedings or by providing guidance documents. As the AQCC brings clarity to these issues, Black Hills will be able to determine if the best interests of its customers are served by opting in to the statutory requirements.

Regardless of the clean energy targets, Black Hills has already, and is continuing to make, significant strides in reducing its greenhouse gas emissions. Black Hills has no coal generation on its system, has met the State's 30 percent Renewable Energy Standard (RES) requirement, and is proposing to add significant new renewable resources. Specifically, in Proceeding No. 19A-0660E, Black Hills has pending before the Commission the Renewable Advantage project, where Black Hills is hosting a request for proposals for new renewable and storage resources of up to 200 MWs to dramatically increase renewable penetration and lower customer bills. Black Hills is well suited to further reduce carbon dioxide and greenhouse gas emissions.

From a transmission perspective, Black Hills has not at this time determined a need to develop new transmission to assist in bringing online renewable resources to reduce greenhouse gas emissions. For example, in Proceeding No. 19A-0660E, concerning Renewable Advantage, Black Hills has received competitive bids for

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[3] *Id.* at 40-2-125.5(3)(a)(I), C.R.S. ("By 2030, the qualifying retail utility shall reduce the carbon dioxide emissions associated with electricity sales to the qualifying retail utility's electricity customers by eighty percent from 2005 levels.").

large-scale renewable and storage resources, and these proposed resources seek to interconnect with the Black Hills' system at points on already existing or planned transmission infrastructure. Black Hills has not identified new transmission necessary to assist in meeting emission reduction policies, targets, or goals.

ii. Tri-State Response

Colorado Revised Statute § 40-2-125.5(3) requires qualifying retail utilities to meet certain clean energy targets related to reductions in carbon dioxide emissions associated with retail electricity sales. Tri-State is not a qualifying retail utility as defined by statute and it has no retail electricity sales. As a result, the clean energy targets set forth in the statute do not apply to Tri-State. Tri-State anticipates that carbon dioxide and greenhouse gas emission reduction requirements being developed presently by the AQCC will apply to Tri-State and will guide Tri-State's emission reduction efforts associated with its wholesale electricity sales to its Colorado Members.

Notwithstanding the inapplicability of this statute to Tri-State, and while the AQCC's efforts continue, Tri-State is moving forward with its Responsible Energy Plan ("REP"), a transition to clean energy that will expand renewable generation and reduce greenhouse gas emissions while ensuring reliable, affordable, and responsible electricity for its member cooperatives and public power districts ("Member Systems"). The REP commits Tri-State and its Member Systems to significant reductions in emissions of carbon dioxide attributable to Tri-State's electricity sales to Tri-State's Colorado members, including eliminating 100 percent of emissions from our Colorado coal facilities by closing Craig Station and the Colowyo Mine by 2030. By 2030, and relative to 2005 levels, Tri-State will reduce carbon dioxide emissions in Colorado by 90 percent from generation it owns or operates in Colorado, and by 70 percent with respect to electricity delivered to Tri-State's Colorado Members.

These emission reductions are combined with a commitment to a precedent-setting investment in renewable energy resources. By 2024, Tri-State is bringing over 1 gigawatt of wind and solar resources online, meaning 50 percent of the energy Tri-State's Member Systems consume will come from renewables.

Emission reductions associated with the REP will be addressed through resource planning efforts, which, upon approval by the Commission, are an input into transmission planning efforts. The implementation of the REP and Tri-State's approved Electric Resource Plan (ERP) will require detailed analysis of identified resource retirements and resource additions by network customers. Transmission planners must ensure that the transmission system continues to reliably serve identified network customer load. Tri-State has been leading and participating in joint planning studies through the Colorado Coordinated Planning Group (CCPG) to explore transmission system improvements needed to accommodate additional renewable resource development across the state of Colorado while maintaining system reliability which will further support carbon dioxide reductions.

iii. Public Service Response

As a Qualifying Retail Utility under § 40-2-125.5(3)(I), C.R.S., Public Service will bring forward its clean energy plan to reduce the carbon dioxide emissions from its electricity business by 80 percent below 2005 levels by 2030 in its next ERP filing. This Clean Energy Plan will build on its Colorado Energy Plan, approved under the most recent ERP (Proceeding No. 16A-0396E), which will result in the early retirement of two coal-fired generating facilities with a combined generating capacity of approximately 660 MW, the addition of approximately 1,100 MW of wind generation, approximately 700 MW of solar generation and development of 275 MW of large-scale battery storage. The Colorado Energy Plan alone will transform our electric system to more than fifty percent renewable energy by 2026 and is anticipated to achieve a 60 percent reduction in carbon dioxide emissions compared to 2005 levels.

Public Service's clean energy strategy focuses on reducing emissions from fossil fuel generating resources, increasing investment in renewable energy and storage resources, reliable integration of increasing amounts of renewables, continued energy efficiency efforts, and use of advanced technologies. These focus areas reflect a strategic priority for Public Service and its parent company, Xcel Energy, which is to be a leader in transitioning toward cleaner energy. Transmission development will be a critical element for Public Service in the continued transition to cleaner energy resources (renewable generation) – both as it executes on the approved Colorado Energy Plan, and as it develops and implements its forthcoming Clean Energy Plan.

Historically, conventional generation has been located somewhat independently of the fuel source, which could be delivered to the generation site via pipeline and/or rail system. In contrast, renewable generation is critically dependent on location-specific renewable resources for its energy production and thus may be located hundreds of miles away from the load center. In order to support the continued development of renewable resources from the wind- and solar-rich areas of the state, it is important that the transmission system be developed to reliably accommodate these renewable resources.

As part of Public Service's planning process and as considered in developing in Public Service's latest Rule 3627 Report, Proceeding No. 20M-0008E, there are multiple drivers to the planning process, including accommodation of new resources, retirement of existing resources, compliance with state and federal rules and standards, replacement of aging infrastructure, public policy initiatives and, most importantly, maintaining a reliable and affordable electric grid. When possible, Public Service endeavors to take advantage of opportunities to develop projects that can simultaneously support a combination of these goals.

Historically, Public Service's transmission planning process has relied on a resource need to drive the development of transmission plans. However, with the declining costs of renewables and state policy in favor of renewables, Public Service continues to look at resource plans to fill supply shortages due to demand growth,

but also to transition to a cleaner electric generation footprint. Going forward, transmission will be an integral component of achieving both Public Service's and the State of Colorado's clean energy goals. Our transmission planning process will consider the possibility of new resource acquisitions in potentially disparate or remote parts of our region. Between this need to look to new resource areas, and the fact that the Rush Creek Gen-Tie is fully loaded, transmission infrastructure and planning will undoubtedly play an increased role in future resource planning and acquisitions.

Public Service recognizes that better and earlier integration of transmission planning into the resource planning process will be critical going forward as it looks to achieve 80 percent carbon reduction by 2030 as part of its next ERP. Since the 2016 ERP, Public Service's Transmission Planning and Resource Planning groups have been actively collaborating on how to better align their respective processes for future ERPs. This includes earlier identification to Public Service's transmission planners of the size and location of potential resources needed to meet public policy initiatives, so that Public Service can better plan the transmission necessary to accommodate these new resources and reconsideration of what Senate Bill 07-100 provided for transmission to be built in advance of identified generation resources in the identified Renewable Energy Zones.

Public Service's Transmission Planning and Resource Planning departments are coordinating efforts to generally identify the actions that will be necessary to meet Public Service's carbon reduction goals under § 40-2-125.5(3)(I), C.R.S. As part of that process, Transmission Planning has conducted analyses of the potential stand-alone generation injection capabilities of various locations on Public Service's transmission system. Identifying stand-alone generation injection capability is the first step to understand how the existing transmission system might accommodate development of new clean energy resources such as wind and solar. Identifying and maximizing opportunities to utilize the existing transmission system can potentially reduce future transmission costs.

Looking beyond the existing transmission system, in the Joint 10-Year Transmission Plan, Public Service identified and described conceptual new transmission plans that have been developed through the coordinated planning process and that could lay the framework for new transmission infrastructure to support Clean Energy Plan goals. These conceptual plans include the Weld-Rosedale-Box Elder - Ennis 230 & 115 kV Transmission Lines and the Weld County Transmission Expansion, the Lamar Front Range Transmission Project, and the San Luis Valley Project. Using the stand-alone injection capabilities described above along with these conceptual new transmission plans, Public Service is assessing different pathways for how it could achieve the carbon reduction targets of § 40-2-125.5(3)(I), C.R.S through combinations of actions including early coal retirements, reduced coal operations, additional renewable resources (utility scale and distributed) additional storage technologies, and continued expansion of energy efficiency programs, while also maintaining a high level of system reliability.

Through a coordinated effort, Transmission Planning and Resource Planning are utilizing the stand-alone generation injection locations and the conceptual new transmission plans to develop portfolios for analysis that meet the Company's clean energy goals. Preliminary analyses are being conducted using generic cost and performance information for renewable, storage, and other generation technologies, which, in combination with coal-related actions, could be part of a Public Service Clean Energy Plan that will be brought forward to the Commission for approval in the future. Ultimately, the specifics of Public Service's preferred Clean Energy Plan will not be known until Public Service completes its Phase II competitive solicitation evaluation process as part of its next ERP and reports the results of that process to the Commission. This is anticipated to occur in 2022.

Through these preliminary analyses, Public Service has been able to identify several common transmission system criteria violations, as well as criteria violations unique to each conceptual carbon reduction portfolio studied. Transmission Planning presented the common transmission system criteria violations at the May 21, 2020 CCPG meeting. These include overloads in the Denver Metro area due to an

increase in power transfer into the load center, and the Pawnee to Story 230 kV line overload due to an increase of power flow on this line. Another set of transmission projects that may be needed to help Public Service meet its carbon reduction targets include the networking of the Rush Creek Gen-Tie (which was studied as part of the Lamar Front Range Task Force Study), and the Northern Greeley Area Transmission Plan (which aligns with the Weld County Transmission Plan).

Transmission Planning will make available specific criteria violations as well as the necessary upgrades as they become available at future CCPG meetings, FERC 890 meetings and through other stakeholder outreach meetings that may be scheduled.

B. Discussion Regarding Whether and, if so, How Each Utility Intends to Address Policy Initiatives in the Governor's Roadmap

On May 30, 2019, Colorado Governor Jared Polis released his administration's "Roadmap to 100% Renewable Energy by 2040 and Bold Climate Action" (the "Governor's Roadmap"). Among other aspects of Gov. Polis's vision, the Governor's Roadmap identifies the goal of Colorado being powered by 100 percent renewable energy by 2040. The Governor's Roadmap also describes the policies and actions the Administration is taking and will take to advance this goal, as well as how the 100 percent by 2040 goal relates to other aspects of the Governor's vision. While Governor Polis has issued a number of Executive Orders that complement the Governor's Roadmap,[4] the Roadmap itself is not an Executive Order nor does it have the force of law comparable to recently enacted energy legislation such as House Bill 19-1261 and Senate Bill 19-236.

Notwithstanding the fact that the Governor's Roadmap does not create an enforceable obligation, the Joint Utilities acknowledge it sets forth a present public policy initiative of the current Administration, which could lead to future policy initiatives. As such, the Joint Utilities agree that it is appropriate to consider the Governor's 100 percent by 2040 goal in connection with their conceptual long-range

[4] *See, e.g.*, Executive Order D 2019 016, Concerning the Greening of State Government.

scenarios developed under Commission Rule 3627(e). Therefore, as directed by the Commission, the following supplemental information "addresses whether and how the Utilities plans to make progress toward meeting the Governor's Roadmap goal of providing consumers with energy generated from 100 percent clean energy resources by 2040."[5]

i. Black Hills Response

Black Hills appreciates the Governor's Roadmap as a policy perspective on increasing renewables and reducing greenhouse gas emissions. The Governor's Roadmap can be used to inform individual litigated proceedings at the Commission. For instance, on May 8, 2020, in Proceeding No. 20A-0159E, Black Hills submitted its Ready EV Plan, representing Black Hills' first Transportation Electrification Plan. The Governor's Roadmap addresses policies to support transportation electrification. The Commission and interested parties can thus examine how the Ready EV Plan furthers the Governor's policy prerogatives in that individual proceeding.

As another example, the Governor's Roadmap addresses the policy need to reduce carbon dioxide emissions. The Commission and interested parties can address that policy in the Company's ongoing Renewable Advantage proceeding, Proceeding No. 19A-0660E, as well as in future ERP proceedings.

Focusing on transmission, the Governor's Roadmap supports consideration and evaluation of enhanced electricity markets in Colorado. Toward that end, in December 2019, Black Hills announced the intent to join the California Independent System Operator (CAISO) Western Energy Imbalance Market (WEIM). Black Hills, together with the other participants to the Joint Dispatch Agreement, are continuing their work to enter this market. The Commission and interested parties can examine

[5] Commission Decision No. C20-0213-I, ¶ 18.

Black Hills' proposal to join the CAISO WEIM in comparison to the policy issues related to enhanced electricity markets contained in the Governor's Roadmap.

ii. Tri-State Response

On January 15, 2020, Tri-State announced its REP, which will dramatically and rapidly advance the association's clean energy portfolio and its programs to serve its Member electric cooperatives and public power districts, including its 18 Colorado Member Systems. A key component of the REP is the investment of over $1 billion in contracts for 1,000 MW of renewable wind and solar projects by 2024, and up to an additional 1,000 MW of renewable energy projects by 2030.

As of the date of this Supplemental Report, Tri-State provides 31 percent renewable energy to its Colorado Members. Under the REP, that amount will increase to 50 percent by 2024. Furthermore, Tri-State has set a goal of striving to reach 100 percent clean energy resources in Colorado by 2040.

These aspects of the REP are complemented by Tri-State's announcement that it will eliminate 100 percent of the carbon dioxide emissions from its coal-fired power plants in Colorado by 2030. Additionally, Tri-State has put in place programs to provide its Member Systems greater flexibility in developing local renewable energy projects, including community solar generation. In the context of Rule 3627, these aren't just "conceptual long-range scenarios," these are present actions intended to achieve the goals of the REP.

Tri-State anticipates that it may begin discussing steps associated with the REP as early as its next ERP that is scheduled to be filed with the Commission on December 1, 2020, and will follow-up on those steps and progress made in its next ERP that is scheduled to be filed on June 1, 2023.

In the interim, Tri-State believes that the three conceptual long-range scenarios discussed in its portion of the Utilities' Joint 2020 Rule 3627 Report are consistent with and complement the vision of the Responsible Energy Plan. Scenario #1 – Increased Role of Distributed Energy Resources – contemplates the increased role

of a number of technologies that constitute renewable energy resources as defined in § 40-2-124(1)(a)(VII), C.R.S. Whether developed by Tri-State or its Colorado Members, such resources will play a role in meeting the Governor's Roadmap goal of 100 percent clean energy by 2040. Scenario #2 – Increased East-West Interconnection – contemplates the possibility of new DC-Tie facilities and new DC transmission lines between the Eastern and Western Interconnections. Such improvements will provide an opportunity for Tri-State to tap-into renewable energy resources in the east through its participation in the Western Energy Imbalance Service so as to complement the renewable energy resources developed in Colorado to serve its Members' load. Finally, Scenario #3 – Increased Energy Storage – contemplates significant advancement and growth of energy storage technology that not only could, in appropriate circumstances, defer or replace traditional transmission projects, but also potentially assist in the integration of variable renewable energy resources. Each of Tri-State's 2020 conceptual long-range scenarios represent potential system improvements that would support the goals of the REP.

iii. Public Service Response

The Governor's Roadmap proposes aggressive action to achieve 100 percent renewables across the Colorado economy by 2040. Xcel Energy's, and in turn, Public Service's, plans for a 100 percent clean energy future by 2050 will make significant progress toward this overarching objective of the Roadmap. Xcel Energy's practical yet proactive approach considers the technology limitations and factors in the challenges that will need to be solved to reach the goal of a 100 percent clean energy portfolio by 2050, while spurring the necessary innovations to support this transition. Long before 2050, Public Service's plans to achieve 80 percent carbon reduction by 2030 will undoubtedly make significant strides toward the Roadmap's 2040 goal. And resource plans occurring every four years along the way can continue to allow the Commission, utilities and stakeholders to calibrate the cost and feasibility of progress toward 2040 or 2050 targets.

Public Service believes its work toward the clean energy targets outlined in § 40-2-125.5(3), C.R.S. will undoubtedly provide lessons learned that Public Service can build upon and apply toward its 100 percent clean energy by 2050 goal. Conceptually in the next 30-year timeframe, Public Service will focus on increasing renewable resources, managing existing customer load, developing a more robust transmission system, and incorporating new, dispatchable, carbon-free technologies.

For example, Public Service is actively exploring energy storage solutions through ongoing pilots through its Innovative Clean Technologies program first approved in Proceeding No. 09A-015E. Through these pilots, Public Service is assessing the capabilities of battery energy storage systems on its distribution grid and increasing its understanding of how battery energy storage can help manage impacts on the distribution system with high penetration of photovoltaic generation. Public Service is also pursuing Commission approval of more involvement and exploration in this area through its proposed Community Resiliency Initiative (CRI) in Proceeding 19A-0225E. If approved, the CRI would develop seven microgrid projects totaling 6 MW and 15 MWh of Company-owned energy storage system projects to proceed pursuant to § 40-2-203(4), C.R.S. Public Service anticipates that these targeted, community-based microgrid projects will enhance safety, reliability, and resiliency of the electric grid while expanding the integration and utilization of battery technology on the Public Service's system.

It is anticipated that an increase in energy storage will be required to achieve 100 percent clean energy future. Understanding this need, Public Service will seek opportunities to develop energy storage throughout the system. As advancements in energy storage technologies are developed, energy storage solutions will also begin to emerge as solutions to various system issues such as regulation, frequency response and contingency reserves. Through the CCPG and the Energy Storage Work Group, Public Service will continue to develop its understanding and share its findings of energy storage and non-transmission alternatives with neighboring utilities and stakeholders.

In addition to pursuing energy storage solutions, reducing on-peak energy usage through energy efficiency programs and new or innovative rate design can also play an important role in reducing systemwide carbon dioxide emissions and other pollutants, while delaying the need for system upgrades. Public Service's Demand-Side Management program has a longstanding and successful track record of helping customers manage their energy usage more efficiently. On the rate design front, Public Service has recently implemented a dedicated Commercial electric vehicle (EV) rate that encourages customers to shift from on-peak to off-peak EV charging, which was approved through Proceeding No. 19AL-0290E, and Public Service has also proposed a default time-of-use rate for its Residential electric customers through an advice letter filed in Proceeding No. 19AL-0687E.

Public Service continues to evaluate opportunities to build transmission, which will encourage and accommodate the electrification of other industries such as the transportation and oil and gas industry. Both of these efforts hold promise to improve air quality and the health of the communities we serve. Public Service anticipates that its Transportation Electrification Plan (TEP), recently filed in Proceeding No. 20A-0204E, will help enable Governor Polis' vision through decreasing carbon dioxide emissions and other pollutants from the transportation sector, and through its TEP, Public Service is proposing several initiatives that facilitate charging optimization, which can help improve the integration of renewables onto our system and reduce system-wide carbon dioxide emissions through encouraging a shift from on-peak to off-peak charging.

Public Service views successful implementation of its Colorado Energy Plan, described above, as a springboard that will position us to better understand the reliability implications of integrating and accommodating significant new renewable generation resources onto our system in a cost-effective manner. Public Service understands that the ultimate transition away from traditional, centralized fossil fuel plants will require new and innovative transmission and distribution solutions to bring resources online from previously undeveloped parts of the region. This transition also presents added challenges for transmission planning, including the potential

need to traverse geographically sensitive and unique areas, navigate a complex array of siting and land rights issues (including locally and federally protected lands), and address the potential for increased wildfire risk. Conversely, these projected transmission developments will provide an opportunity to take advantage of new available technologies or innovative applications of existing technologies while further considering non-transmission alternatives.

Though it is difficult to anticipate the impact the actions outlined in the Governor's Roadmap and Public Service's efforts that support this vision will have in aggregate from a transmission planning perspective, Public Service will maintain a steady approach to safely modernizing the grid with renewable energy reliably, while keeping customers' energy bills low.

C. Identification of Anticipated Organized Market Information as Applied to Each Scenario

According to the Commission's Decision, the "Utilities shall include additional analysis regarding organized market considerations. Specifically, updates should address considerations of organized market analysis that were made in each respective scenario. The Utilities shall identify participation in potentially separate regional markets. Additional discussion regarding the result of this divergent participation, including anticipated participation in energy imbalance market or day-ahead markets, should be addressed further for consideration and comment."[6]

i. Joint Utilities' Response

Organized markets continue to evolve within the Western Interconnection and, over the last year, Black Hills, Public Service, and Tri-State have publicly declared their intent to participate in separate energy imbalance markets. Public Service, and the Joint Dispatch Agreement (JDA) participants, including Black Hills, announced in

[6] Proceeding No. 20M-0008E, Decision No. C20-0213-I, (mailed date April 7, 2020), page 7, ¶19

December of 2019 their intention to pursue negotiations on an implementation agreement with CAISO for its Balancing Authority (BA) to participate in the WEIM. Tri-State, along with Basin Electric Power Cooperative (Basin Electric) and the Western Area Power Administration (WAPA), announced in September 2019 their intention to become members of Southwest Power Pool's (SPP) Western Energy Imbalance Service (WEIS) market.

Participation in separate energy imbalance markets is not expected to alter the process under which the utilities subject to Rule 3627 plan their transmission systems. Each utility will continue to provide transmission service under its own Open Access Transmission Tariff (OATT), subject to the Federal Energy Regulatory Commission's (FERC) orders governing the administration of their respective OATTs, including FERC Orders 888, 890, and 1000. Black Hills, Public Service, and Tri-State will continue local planning coordination through CCPG, and will continue to be members of the WestConnect planning region as part of their regional planning obligation under FERC Order 1000.

While participation in energy imbalance markets should not affect the way transmission planning is coordinated and completed, it may provide opportunities for each utility to examine opportunities beyond traditional system reliability metrics. Both the WEIM and the WEIS are real-time energy imbalance markets with nodal or Location Marginal Pricing (LMP), which provides a level of price transparency that may assist with identifying opportunities for transmission projects that provide greater transfer capability with other market participants, congestion relief, or more efficient generation siting.

Black Hills, Public Service, and Tri-State will continue to examine future opportunities for market development, which may include expanding their participation into a full Regional Transmission Organization (RTO), or other day-ahead market construct. A discussion of each utility's perspective on future organized market constructs, including RTOs, is addressed below.

ii. Black Hills Response

Black Hills has continually analyzed opportunities for participation in a broader regional market, whether through our participation in the now defunct Mountain West Transmission Group (MWTG), or working with our BAs and their other customers to analyze new opportunities such as the WEIM and WEIS. Internal analysis takes place in a cross-functional manner across many parts of the organization. The impacts of regional markets can touch every facet of the organization, and most importantly, our customers. Savings and costs related to participation in regional markets are passed directly to customers, so it is imperative that any regional market option demonstrates *long-run net benefits*.

Since the breakup of the MWTG the two most viable options for regional market participation have been the WEIM offered by the CAISO, and the WEIS offered by SPP. Both the WEIM and WEIS are energy imbalance markets where real-time energy imbalances are handled through a Security Constrained Economic Dispatch (SCED). Transmission service is similar in both markets (though not identical), and leverages unutilized transmission capacity in real-time to deliver imbalance energy, thereby maximizing the use of transmission capacity that would otherwise be a sunk cost. The decision to join an energy imbalance market is largely driven by the BA, which is responsible for providing energy imbalance service through either their OATT, or a contractual arrangement with their customers.

Black Hills is a BA customer of Public Service and participates in the JDA along with Platte River Power Authority (PRPA), and Colorado Springs Utilities (CSU). Public Service and the other JDA partners agreed to participate in a joint production cost study during 2019 to examine potential energy savings. The results of that study were used in conjunction with other quantitative and qualitative analysis as inputs into the Public Service announcement in late 2019 that the JDA entities would look to begin negotiations with the CAISO to join the WEIM.

Black Hills did not consider regional market scenarios in its 20-year conceptual scenario planning due to the high uncertainty surrounding participation in an RTO,

and the fact that energy imbalance markets are not expected to significantly impact the planning process that currently exists between Colorado utilities. Even under the scenario that Colorado utilities participate in multiple energy imbalance markets, local and regional transmission planning would continue to function as it does today. An energy imbalance market does have the potential to increase projects driven by economics or public policy that may be considered within the planning process, including projects that increase transfer capability within the regional market footprint. Black Hills is continuing to examine how such projects would be analyzed in the future, assess our capabilities to perform such planning, and determine how economic or policy driven transmission planning can be incorporated to benefit our customers in the future. Under that assumption Black Hills focused the 20-year conceptual scenarios on areas that were determined to have higher levels of certainty around how our systems may be impacted from a reliability perspective within the 10 to 20-year planning horizon, whether Black Hills is participating in a regional market or the status quo were to continue.

iii. Tri-State Response

Tri-State views an RTO as the linchpin to a clean energy transition and an important and necessary element in the implementation of its REP. An RTO would create cost sharing, a joint OATT, and new planning opportunities that will enable the Rocky Mountain Region to more efficiently and cost-effectively integrate more renewables onto the transmission system, improve transmission system utilization, increase transmission system reliability, and allow Tri-State's Member Systems access to a much larger portfolio of renewable energy. As noted previously, Tri-State is already a member of SPP and placed its Eastern Interconnection facilities in SPP's RTO years ago, resulting in a positive experience and cost savings. Tri-State is joining seven other utilities in SPP's Western Energy Imbalance Service market and represents a step closer to a full RTO. Tri-State believes that some form of an organized market will be in place in Colorado within the 20-year conceptual scenario horizon.

Tri-State believes that the Increased East-West Interconnection long-range scenarios discussed in its portion of the Utilities' Joint 2020 Rule 3627 Report is consistent with the vision of an organized market. Scenario #2 – Increased East-West Interconnection – contemplates the possibility of new DC-Tie facilities and new DC transmission lines between the Eastern and Western Interconnections. Such improvements will provide an opportunity for Tri-State's Member Systems to tap-into renewable energy resources in the Eastern Interconnection. This would be accomplished through its participation in the WEIS or a full-organized market so as to complement the renewable energy resources developed in Colorado to serve its Members' load.

From Tri-State's perspective, the impact of separate organized markets on transmission planning will be minor as local and regional transmission planning would likely occur in a similar fashion as performed today through the CCPG to facilitate coordination and stakeholder input. Due to the highly interconnected nature of the transmission system involving multiple jurisdictional and non-jurisdictional transmission providers, continued coordination of transmission planning and operational efforts would be vital on the local and regional levels. The creation of separate RTOs within Colorado, or within the Western Interconnection for that matter, would not hinder transmission planning as demonstrated by the fact that multiple RTOs exist across the Eastern Interconnection and coordinate effectively. Should separate organized markets develop within Colorado, coordination would continue and, if needed, evolve to continue to ensure plans are developed in a joint, open, and transparent fashion.

iv. Public Service Response

As stated in the 20-year Report, Public Service continues to be involved in regional energy market development. Public Service, along with Black Hills and, most recently, CSU, participates in the JDA. The JDA is a simplified form of an energy imbalance market that dispatches least-cost energy between the JDA participants based on an hourly, system-marginal price and unused available transmission

capacity. In mid-2019, the JDA participants commissioned a joint study to evaluate and compare the costs and benefits for participation in the WEIM sponsored by the CAISO or the SPP WEIS. As described in Proceeding No. 19M-0495E, the JDA participants decided to join the CAISO WEIM. WAPA, Tri-State and Basin Electric made their decision to join the SPP WEIS.

Energy imbalance markets reduce production costs in real-time, which enables participants to capture some of the benefits seen in RTOs with fully organized markets. Unlike an RTO structure, transmission service providers within the CAISO EIM and SPP WEIS will continue to operate and control their own transmission systems in accordance with their existing OATTs. Energy imbalance participants provide generation information to the market operators to improve generation dispatch and use transmission service pursuant to the individual OATTs within the footprint. In an RTO environment, each individual OATT is eliminated in favor of a single OATT (or, "regional tariff") administered by the RTO. A regional tariff allows transmission customers to move power throughout the footprint without paying individual transmission owner tariffs (*i.e.*, rate pancaking), which enables improved generation dispatch by market services, leading to greater production cost benefits. The drawback of a regional tariff includes the cost shifts that occur with lower cost systems subsidizing higher cost systems, the administrative costs of the RTO, and issues around transmission planning and cost allocation, among others.

CAISO is working with stakeholders to evaluate the feasibility of adding a day-ahead component to the WEIM without an RTO structure to enable further production cost benefits for participants. Public Service is involved in this evaluation, but currently there are no concrete proposals for development of the day-ahead component to CAISO WEIM.

Public Service has no expectation of when or if an RTO will be developed and control the transmission system of the former MWTG footprint, or under what terms and conditions that transition may ultimately occur. With that in mind, Public Service's Scenario #1 did not identify any transmission enhancements that would be

likely under an RTO environment for the 20-year conceptual scenario. Furthermore, Public Service has proposed no transmission enhancements that are associated with its participation in the WEIM.

At this time, there are no concrete plans to increase transmission transfer capability between the JDA participants and other CAISO WEIM utilities. Public Service will be evaluating the opportunities for future capability, whether based on new transmission construction or acquisition of transmission service, and such evaluations will include more robust considerations of production cost savings, renewable energy integration benefits, and savings in contingency reserves obligations. Public Service expects that if any new transmission upgrades arise as a result of this evaluation, they would be brought to the CCPG, WestConnect, and other stakeholder review committees for further evaluation. Such projects could ultimately be included in future Rule 3627 reports in either the 10 or 20-year plans.

D. Information Regarding the Effects of Technology Advancements, Specifically as Applied to Each Scenario

According to the Commission's Decision, the Commission requests "supplemental information describe[ing] whether and if so how, the Utilities will address the anticipated effects of technology advancements, particularly regarding storage capabilities, on transmission and the proposed 10 and 20-year plans."[7]

i. Joint Utilities' Response

The Joint Utilities do not anticipate that technology advancements will impact the planned transmission projects outlined in the 10-year transmission plan. However, the conceptual transmission projects listed in the later years of the 10-year plan may benefit from future advancements in technology. The Joint Utilities through CCPG are developing guidelines and a process to evaluate non-transmission alternatives.

[7] Proceeding No. 20M-0008E, Decision No. C20-0213-I, (mailed date April 7, 2020), page 7, ¶20

The guidelines and process are intended to assist project sponsors and engineers in evaluating and comparing benefits of transmission system upgrades with non-transmission alternatives (*i.e.* non-wire alternatives). In future reporting, we anticipate that a single term will be agreed upon among the Joint Utilities. To ensure the Joint Utilities remain up to date with storage advancements, they will continue evaluate competing non-transmission alternatives for new transmission projects through their individual utility project development process.

Transmission planning and the projects developed by the utilities' transmission planning groups primarily focus on the reliable delivery of energy generated by a resource to load centers, which often are some distance away from the generating resource. Transmission project drivers include load growth, new generation sources, and aging infrastructure, among others. Transmission projects are developed to ensure reliability and compliance with applicable North American Electric Reliability Corporation (NERC) reliability standards. The Joint Utilities' existing transmission planning processes evaluate energy storage systems on their ability to possibly mitigate the need for new transmission projects and provide supporting services to the grid. An example of a supporting service is the ability to provide reactive power and voltage support to ensure reliable system performance. This benefit is often addressed with traditional capacitor or reactor projects. The costs and proven benefit of capacitor or reactor projects has not been surpassed by any of the recent advancements in energy storage technology. Further, it is possible energy storage systems may be able to defer new transmission and distribution projects in the future by providing energy in strategic areas to keep loading on nearby transmission lines below specified ratings. According to a 2018 U.S. Energy Information Administration's ("EIA") report on U.S. Battery Storage Market Trends (the "EIA Report"), the megawatt capacity installed and attributed to transmission or distribution project deferral was 45.1 MW of the 551.7 MW capacity total reported.[8]

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[8] U.S. Battery Storage Market Trends, EIA (May 2018), p. 23, a*vailable at* https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

In contrast, the amount of installed capacity attributed to frequency regulation is 486.7 MW. This point highlights the physical limitations associated with energy storage systems as they compare to transmission development. However, other benefits such as frequency regulation and providing ramping/spinning reserves suit today's energy storage performance attributes well. The Joint Utilities anticipate the existing limitations in capacity and duration will continue to improve and thus the Joint Utilities will continue to evaluate non-transmission alternatives when developing future transmission projects.

The EIA Report further finds that over 80 percent of U.S. large-scale battery storage power capacity is currently provided by batteries based on lithium-ion chemistries.[9] It is anticipated that technology advancements will continue to progress in lithium-ion technology. Further, continued development of flow battery technology is another energy storage technology which shows promise. Flow batteries' overall capacity is a function of the tank size in which the chemical solutions are stored. Flow batteries are characterized by their long cycle life and are projected by EIA to have a long operational lifetime.[10] The Joint Utilities anticipate these technologies will continue to enhance their ability to accommodate a variety of future resources and improve system flexibility.

The price of storage technology is generally declining. According to the EIA Report, "battery systems with shorter durations will typically have lower normalized power capacity costs ($/kW) than batteries with longer nameplate durations. The opposite is generally true when examining normalized energy capacity costs ($/kWh), as the total system costs for longer-duration systems are spread out over a larger basis of stored energy. Nonetheless, the range of normalized cost values is driven by technological and site-specific requirements."[11] Thus, though the cost of energy

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[9] *Id* at 8.

[10] *Id*.

[11] *Id* at 13.

storage is trending downward, data should be considered based on a variety of specific attributes and a degree of caution should be taken when applying this broadly. The Joint Utilities will continue to evaluate non-transmission technologies as alternatives to future transmission projects in their 10-year plan and future plans.

Each Utility provides additional information in turn, below.

ii. Black Hills Response

Black Hills has begun integrating storage into its transmission consideration processes and planning. To further consideration of storage capabilities and costs, Black Hills commissioned a study undertaken by HDR to provide a technical overview of the current state of the energy storage industry, including types of commercially available energy storage technology that may be applicable as non-wire alternatives in Black Hills' transmission and distribution planning processes. This study has been filed in Proceeding No. 20-0176E, which is Black Hills' Rule 3207 Report proceeding. The study is also included as Appendix A to this supplemental report.

The HDR analysis reviewed commercially available NWAs and its applicability to projects. For cost comparison, the cost of an energy storage system using lithium-ion batteries was used because of its availability and ease of use. The results of the HDR analysis indicated that while non-wire alternatives, and particularly Battery Energy Storage Systems (BESS), have made significant improvements in availability and technology. However, they still have difficulty on a general basis performing as cost-effective alternative solutions for transmission or distribution system projects.

Black Hills expects energy storage to impact future distribution and transmission plans. At this time, Black Hills asserts that storage may pose greater opportunities for customer benefits on the distribution system, as opposed to the transmission system. This finding can change if full RTO participation is pursued. As Black Hills continues to assess and consider energy storage, its future transmission plans, including 10 and 20-year scenarios, may be shaped by this resource.

iii. Tri-State Response

Tri-State regularly considers technology advancements, such as energy storage systems, as part of its transmission planning process. Other potential technology advancements that are considered in transmission planning include, but are not limited to, Flexible AC transmission system (FACTS) devices, high-temperature low-sag (HTLS) line conductors, and dynamic line rating equipment. All of which are meant to enhance stability, controllability, and/or power transfer capability on the transmission system. FACTS devices include series and shunt reactive devices, which influence transfer capability and/or voltage stability/control, respectively. HTLS line conductors and dynamic line rating equipment have the potential to increase the transfer capability of a line, offering the potential to delay the need for new transmission line construction.

In particular, energy storage, in appropriate cases, has the potential to defer or replace more traditional transmission projects by providing congestion relief. While energy storage may be helpful in firming up variable renewable energy resources, it is unlikely to replace transmission projects primarily related to connecting such resources to the grid, or to serve new loads. Energy storage costs have been falling quickly, however, the energy storage capacities necessary to address transmission issues are generally very large.

The considerations of technology advancements, such as energy storage systems, in relation to near-term transmission planning projects are summarized in Tri-State's annual filing under Commission Rule 3206. Energy storage will likely play an increasing role in Colorado's energy mix, and is a consideration in Tri-State's resource planning. Should the price of energy storage continue to fall, storage may become a more significant component of Tri-State's transmission system planning as well.

iv. Public Service's Response

Public Service does not anticipate an immediate impact on current planned projects in the 10-year plan. However, it is reasonable to expect that conceptual projects in the outermost years of the project plan may be impacted or modified by the introduction of new technology advancements. To the extent this occurs, Public Service would update the Commission in future Rule 3627 filings.

As mentioned above, performance advancements in lithium-ion battery and flow battery technology coupled with more competitive costs will contribute significantly to the increase in use and implementation of these technologies. As battery technology becomes more prevalent, opportunities may emerge for batteries to assist in mitigating operational and planning issues on the transmission system such as primary frequency response, regulation, and contingency spinning.

Further, Public Service anticipates that renewable resource technologies will continue to advance in terms of efficiency. For example, one manufacturer claims up to 35 percent increase in production with the use of bifacial solar modules versus that of a single sided panel.[12] The bifacial solar module exposes both the front and back of the solar cells thus increasing the energy production. It is reasonable to expect that existing plants may consider this new technology as a future upgrade to their existing site. Likewise, as power electronics such as inverters and power point trackers advance, an opportunity may present itself to reduce losses and capture more energy out of an existing plant's footprint. Advancements in power electronics also show promise in supporting transmission line compensation and may be used an alternative to traditional methods to influence power flow.

Public Service will continue to evaluate advancements in energy storage and non-wires alternatives to address potential applications on its transmission system.

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[12] *See* https://www.prismsolar.com/our-products.

E. Clarifications Regarding DER Resources and DG

In its Decision, the Commission indicated that it would find clarifications with respect to usage of the terms "DER" and "DG" to be useful, stating "[s]upplemental clarification and analysis should explain the similarities and differences regarding the presented terminology provided in the respective DER scenarios and DG scenario, including specifically Public Service clarifying its use of DER as opposed to DG. In addition, Utilities should clarify whether and how modeling is being conducted for the respective scenarios regarding the DER and DG concepts."

Within Paragraph 21 of its Order, the Commission requests clarification of usage of the terms Distributed Energy Resources (DER) and Distributed Generation (DG) by Black Hills, Tri-State, and Public Service in their 20-year Scenarios 1, 1, and 3, respectively. First, these Scenarios are presented at a high level, essentially as conceptual discussions to "assist with the identification of strategic choices that utility planners, project developers, regulators, and advocates may reasonably need to consider over a 20-year time period."[13] Consistent with past practice, quantitative analysis was not presented by the utilities.

Second, the usage of these two terms in the particular context of these three Scenarios has more similarities than differences. The term "DER" can have a very broad meaning, inclusive of distributed solar, distributed storage, energy efficiency, demand response, electric vehicles, distributed fuel cell generation at customer sites and possibly more potential types of distributed resources. However, all three utilities' Scenarios in this area focused more on solar DG, which is arguably the most prominent form of DER today. For example:

- Black Hills' first listed Assumption in its Scenario #1 ("Significant Penetration of Distributed Energy Resources") is "Public policy initiatives couple with continued public interest toward rooftop/-community solar may increase the current distributed capacity." The second Assumption is "Typical *power*

[13] Proceeding No. 18M-0080E, Public Service Company of Colorado, Tri-State Generation and Transmission, and Black Hills Energy Combined Rule 3627 20-Year Report, page 1.

output curves for renewable resources may interact with typical load curves to cause flows and voltages not seen in the current system" (emphasis added). Black Hills' discussion generally relates to increased distributed generation, though the concept is teed up as DER.

- Similarly, TSGT's Scenario #1 ("Increased Role of Distributed Energy Resources") focuses strongly on distributed generation. The first Assumption therein is "The price of Solar PV continues to fall." The second Assumption is "There is continued interest and increased penetration of community-based and behind-the-meter business models that make solar PV available to more consumers." Clearly, solar DG is a strong element of this scenario. Much of TSGT's analysis of this Scenario under "Potential Benefits and Transmission Impacts to Colorado" speaks directly to increases in distributed generation implicitly or explicitly.
- Public Services' Scenario #3, ("High Penetration of Distributed Generation"), as the Commission observes, focuses on increased solar DG. Here, Public Service focuses in a more explicit way on distributed solar generation in this Scenario, but the Black Hills and TSGT Scenarios are, in effect, not dissimilar.

In summary, the Joint Utilities agree that DERs encompass a broad set of applications and technologies in the utility sector. In developing these particular Scenarios in this 3627 Report, however, the three utilities cover fairly similar ground in focusing on distributed solar at the high level presented for the Rule 3627(e) long-range scenario. Further, over a 20-year time horizon, the multiple types of DERs could evolve in different directions far beyond the work scope and objective of the 3627 report. This is not to say that broader DER scenario analysis is not useful. Monitoring and ongoing scenario thinking around a broad set of DERs is appropriate for future Rule 3627 planning and other planning or scenario activities at the Commission.

Additionally, as a point of clarification for Paragraph 21 of the Order, while modeling was *not* performed by each of the utilities for these 20-year conceptual scenarios regarding DER and DG, it should be mentioned that CCPG *did* perform 2040 conceptual power flow modelling[14] and this modelling included DG. As inputs to the

[14] *See* 2020 Rule 3627 20-Year Conceptual Scenario Report, page D-5 and following.

CCPG 2040 modelling, each of the utilities provided their mix and type of renewable resources that existed in 2017, and the renewable resources they anticipate adding to their system by 2040, to fulfill their energy requirements under Colorado's statutory RES. DG is a renewable resource to comply with RES. Modelling of DG was therefore conducted through the CCPG 2040 conceptual power flow modelling for the 20-Year Conceptual Scenario Report.

Each Utility provides additional information in turn, below

i. Black Hills Response

Black Hills considers "DG" to be a reference to renewable generators in Colorado, both retail and wholesale, to comply with the state's RES. Black Hills has transitioned to using the term "DER" in its documentation to refer to the interconnection of DG and other technologies such as energy storage systems. Transmission planning has started group discussions on the need to coordinate models for the purpose of studying potential back feed on the transmission system associated with DER loads. This is a new process and still in the discussion phase and is planned to be investigated further as the distribution planning group continues to refine and implement new distribution planning processes.

ii. Tri-State DER Response

From its perspective and for purposes of its transmission planning, Tri-State views the terms "distributed energy resource" and "distributed generation" as being synonymous. From a transmission planning perspective, DER is generally located behind the meter on a Member System's distribution network.

Existing, and future, DER are reflected in the transmission planning model's load models, which have load and distribution generation components. Within the transmission planning models, the addition of DER generally appears as a reduction in network load. DER are typically variable in nature so the load models have the ability to toggle the status of the DER from on-line to off-line, allowing the transmission system to be planned appropriately for the scenarios where the DER

are on-line or off-line. Further, the addition of DER can alter the transient performance of the transmission system in a given area, which is factored into transmission planning studies through Western Electricity Coordinating Council's (WECC) dynamic load models, which factor in DER, if it exists.

An aspect of Tri-State's REP is an emphasis on increased flexibility for Members to self-generate, which could lead to more behind-the-meter DER. Due to modeling initiatives at the WECC level which the Utilities participate in, transmission planning models will continue to be updated to reflect DER as levels increase.

iii. Public Service's Response

The Commission requests "specifically Public Service clarifying its use of DER as opposed to DG."[15] Public Service presumes the Commission intended instead to say "clarifying its use of DG as opposed to DER," as DG is the term the Company used in its Scenario #3: High Penetration of Distributed Generation. Public Service selected the term "DG" versus "DER" in its Scenario #3 because it was focused in that Scenario on the potential transmission planning implications of DG, especially DG solar. Public Service notes that distributed solar is the most prominent DER generation resource in its service territory at this point - on Public Services' system alone, there are over 50,000 installations of on-site solar distributed generation. DG solar could have the general effect of decreasing the amount of large-sale generation planned or built, and thus the amount of transmission investments built, but with a potential countervailing effect of requiring incremental distribution system investments.

By contrast, a broader definition of DER in scenario planning could have different effects depending on the DER in question. For instance, a scenario focusing on electric vehicles as DERs could increase the need for large-scale generation and transmission planning and development. This scenario, and potentially many others

[15] Proceeding No. 20M-0008E, Decision No. C20-0213-I, (mailed date April 7, 2020), page 8, ¶21

possible under the broader umbrella of DERs, was not explored by Public Service in its Scenario #3. Public Service recognizes that it is likely that further exploration of a broader set of DERs in future scenario or planning exercises may be merited. But again, Public Service, like the other two utilities, focused primarily on DG solar in this particular Scenario in this report. Public Service also briefly explored a broader set of DERs under its Scenario #4, which covers the 100% Renewable Energy by 2040 goal set forth in the Governor's Roadmap.

F. Further Detail Concerning Local Distribution Company

According to the Commission's Decision, the Commission seeks additional explanation regarding the elimination of the gas LDC described in Public Service's Scenario No. 5.[16] The Commission requests that Public Service expand on its explanations and reasoning that culminated in Scenario No. 5, to allow for a better understanding of the underlying assumptions it made in presenting this possibility.

i. Public Service Response

Public Service Scenario #5: LDC Gas Phaseout

In its Decision No. C20-0213-I at paragraph 22, the Commission requests that "Public Service should expand on its explanations and reasoning that culminated in Scenario No. 5, to allow for a better understanding of the underlying assumptions it made in presenting this possibility." Public Service discussed the main arguments for the inclusion of Scenario #5 in the original Rule 3627 Report, and we appreciate the Commission's interest and the opportunity to expand on our rationale for including this scenario. While Public Service is not aware of any specific proposals to phase out any gas LDC system in the U.S., or any Colorado proposals to limit any gas LDC systems, cities and municipalities in other parts of the country have put forward and, in some cases, approved policy proposals that would limit or block new

[16] Proceeding No. 20M-0008E, Decision No. C20-0213-I, (mailed date April 7, 2020), page 8, ¶22

growth of gas LDC systems, as the examples in our scenario highlighted. Here in Colorado, policies such as House Bill 19-1261, may eventually create some level of scrutiny on greenhouse gas emissions from customers of the LDC sector, which the Company reiterates is different than what Public Service would be responsible for with regard to its own methane emissions.[17] It remains unclear if rules regulating customer emissions will or will not be contemplated by the State in the context of House Bill 19-1261.

However, in order to demonstrate the significant potential impacts to the transmission system, Public Service included this LDC phaseout scenario in the original Rule 3627 Report. Public Service believes the gas LDC phaseout scenario would be unlikely and extremely challenging to implement. As highlighted in the Scenario, significant additional generation and thus transmission would be needed to replace the service provided by the Company's gas LDC system. To illustrate how dramatic this change could be, on the 2019 maximum daily output day, our gas system delivered 2,139,420 mmBtu.[18] The electrical equivalent of this would be 26,000 MW, or more than three times Public Service's peak electrical load.[19] Heat pump efficiency gains might reduce this figure, but it would still clearly be significant. To further illustrate, the Scenario pointed out how Public Service's electric system would likely shift from summer peaking to winter peaking in order to serve the new electrical load created by heating needs in the winter, which could also impact the need for more intermittent renewable energy resources. Public Service also points out that we currently serve, and are obligated to serve, 1.54 million natural gas customers in Colorado. The scenario to eliminate the LDC would thus require well over a million individual decisions to fuel switch away from gas to another energy source.

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[17] The Roadmap appears to create a 100 percent renewable energy goal across the economy, implying all sectors, by 2040.

[18] Source: Public Service Company of Colorado Form 10-K, page 7.

[19] 2,139,420 mmBtu * 1000000 btu/mmBtu ÷ 3413 btu/kWh ÷ 1000 kWh/MWH ÷ 24 hours/day = 26,119 MW.

In summary, Public Service offered this LDC phaseout scenario in the original Rule 3627 Report as a bookend to illustrate the dramatic nature of the potential implications on the transmission system. Public Service believes this scenario is unlikely, and that any future significant trend to reduce usage of the gas LDC system, if it comes to pass, would be many years away. Further, Public Service believes that progress can be made to reduce the greenhouse gas footprint of customers of the existing gas system through measures such as increased natural gas energy efficiency measures, voluntary beneficial electrification programs, renewable natural gas, and continued efforts to reduce methane leakage on the LDC system as well as upstream of it. We are seeking to do all of these things. This scenario is informative for the ongoing public policy discussions.

III. Models and Model Outputs

According to the Commission's Decision, "[t]he Joint 10-Year Transmission Plan and 20-Year Conceptual Scenario Report as supplemented with information required by this Decision shall include all models used and an explanation and copy of model outputs. Additionally, updates shall include discussion of the Basis of Plan, Identified Issues, and any Resource Requirements including Costs, Quality Metrics, and Stakeholder Register."[20]

The Joint Utilities respond as follows:

As an initial matter, the Joint Utilities cannot provide the models used in the Joint 10-Year Transmission Plan and 20-Year Conceptual Scenario as they are considered Critical Energy Infrastructure Information (CEII) and require non-disclosure agreements with WECC to be provided. Additionally, model outputs cannot be provided due to each model's wide variety of model outputs, some of which are considered CEII, and are specific to the respective model.

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[20] Proceeding No. 20M-0008E, Decision No. C20-0213-I, (mailed date April 7, 2020), page 8, ¶23

To provide additional context, however, the Joint Utilities believe it may be helpful to provide an overview of how transmission planning is conducted, how transmission models are utilized, and the purposes of such planning. This information may be useful in understanding the fundamental differences between transmission planning and resource planning, and demonstrating why transmission plans are developed, in part, to meet the specific needs identified through resource planning rather than conceptual resource scenarios.

Transmission Planning involves detailed analyses of deterministic planning models developed by the WECC to identify transmission system improvements or additions needed to meet reliability, load serving, or generation needs over a 10-year planning period. The Joint Utilities participate with WECC in the development of the planning models by providing detailed modeling data for existing transmission infrastructure, estimated modeling data for future transmission infrastructure, and expected load and resource information based on forecasts provided by each utility's network customers. Each planning model reflects projected or starting power system conditions (including loads, generation, and topology) for a specific point in time, such as Heavy Summer (expected summer peak loading) with high or low renewables.

WECC develops approximately a dozen planning models each year, typically including the following:

- Five operating cases
    - Reflecting expected system conditions within the next year
        - Heavy/Light Summer
        - Heavy/Light Winter
        - Heavy Spring
- Two 5-year cases
    - Reflecting expected system conditions 5-years into the future
        - Heavy Summer
        - Heavy Winter
- Two 10-year cases
    - Reflecting expected system conditions 10-years into the future

        - Heavy Summer
        - Heavy Winter
- Two or Three Specialized Cases
    - Reflecting specified system conditions in the 5- or 10-year timeframe
        - For example, high renewable generation dispatch in light load conditions.

The WECC planning models are available for download on WECC's website at www.wecc.org once the requisite non-disclosure agreements are executed. The planning models are developed to model "book end" (peak load, minimum load) snapshots of expected system conditions up to 10 years into the future, as well as snapshots of specialized operating conditions (such as high renewables) that may occur, to be utilized in detailed planning studies. Planning models provide numerous types of outputs related to transmission system modeling and performance, however only reflect the system conditions observed in the snapshot in time the model is set up to reflect.

The transmission system, in general, is planned for projected worst-case scenarios, which would be the peak load system conditions leading to only heavy summer and winter loading planning models in the five and 10-year horizons. When performing studies, transmission planners will generally only make adjustments to specific area generation and/or load levels, unless system modeling corrections are required. These adjustments change the model to reflect a desired stressed system condition based on the needs of the study. Sensitivity studies are commonly performed on specific planning models; however, they reflect only a snapshot of specific operation conditions for use in evaluating transmission system reliability.

The planning model inputs are generally fixed values reflecting existing transmission system equipment. Additionally, planning models are developed and utilized solely to evaluate system reliability under specific stressed operating conditions, and do not include economic considerations such as operating costs or the social cost of carbon. To properly evaluate economic considerations and identify cost savings, models need to reflect the variable nature of load and resources over a full year, or multiple years, of

hourly operating points, rather than the specific "point-in-time" operating conditions found in planning models based on fixed load and generation values.

By comparison, resource planning models are stochastic in nature and include variable inputs (including generator operating costs, transmission costs, carbon costs, and load levels, among others) and allow hourly simulations throughout a projected year or years within a single model. The resource plan modeling process allows optimization of resource costs and determination of production cost savings through congestion relief, amongst others. As the Commission approves resource plans, resource information is provided to the transmission planners for inclusion in the WECC planning models for analysis.

The project management terms Basis of Plan, Identified Issues, and Resource Requirements including Costs, Quality Metrics, Stakeholder Register, are directly related to the implementation of individual transmission projects identified in the 10-Year Transmission Plan. However, these terms are not typically used within transmission planning and in the development of the Joint Utilities' 10-Year transmission plan. The basis of the Joint Utilities' 10-Year transmission plan are the WECC planning models utilized to study system performance and the impacts of forecasted system changes (load growth, generation, etc.). Identified issues, from a transmission planning perspective, are analogous to system performance violations/limitations and their associated cause (*e.g.* load growth). To mitigate "Identified Issues" in transmission planning, transmission alternatives are identified and compared by one or more factors. These factors are analogous to Quality Metrics and can include cost, load-serving capability, generation-injection capability, and constructability, and are utilized to select a preferred alternative. A Stakeholder Register within transmission planning is similar to transmission providers impacted by a specific transmission project, also known as affected systems, and independent stakeholders who participate and provide input in transmission planning through CCPG meetings and study groups, Rule 3627 outreach meetings, and FERC 890 meetings.

The Joint Utilities' 10-Year Transmission Plan includes transmission developments needed to meet "Identified Issues", which are related to meeting reliability, load-serving,

generation needs, and/or public policy requirements. The identification of the transmission developments involves detailed analysis of most, if not all, of the WECC planning models developed each year, applying NERC Transmission Planning (TPL) contingency definitions to identify potential system performance violations. The WECC planning models serve as the Basis of the Utilities' 10-Year Transmission Plan. System performance violations generally appear in five and 10-year models allowing adequate time to validate the violation, study potential mitigations, and identify the appropriate solution. Reliability projects in each utility's Transmission Plan are identified to mitigate system performance violations, which can be thermal or voltage in nature, through detailed analysis and are generally the effect of native load growth. Load-serving projects in each utility's Transmission Plan are identified to serve native load growth, which requires the addition or expansion of existing load-serving facilities.

Generation projects in each utility's Transmission Plan are identified through transmission expansion planning to accommodate conceptual resource development or, more commonly, through Generator Interconnection Studies utilizing the same WECC planning models. Pursuant to FERC Order 845, these generator interconnection base models and assumptions are made available upon request once the requisite non-disclosure agreements are executed with the respective Company. Generator Interconnection Studies are performed by the utilities in accordance with their respective OATTs, and allow for unbiased access to the transmission system. However, transmission planning does not site the potential generation in Generator Interconnection Studies. Interconnection Customers specify each potential generator's point of interconnection. Transmission plans to accommodate generators without specific site locations could lead to transmission development in areas that do not meet the needs of a utility's network customers or that contradict a resource plan approved by the utility's regulator.

Public Policy requirements can influence transmission planning directly and indirectly. An example of a direct influence on transmission planning is SB07-100, which required the designation of Energy Resource Zones (ERZs) and the development of 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. An example of an indirect influence on transmission planning are public policy requirements associated with resource plans, and their associated Resource Requirements. Resource plans, as approved, are provided to the transmission planners by each utility's network customers, and are subsequently included in WECC planning models, which form the Basis of each 10-Year Transmission Plan.

A 20-year planning model reflecting peak and off-peak conditions is developed through CCPG from a 10-year WECC planning model. The 20-year planning models reflect projected renewable energy development based on current RES requirements for investor-owned utilities and cooperatives, as well as conceptual transmission projects. The projected renewable development in the 20-year model that may not be part of an approved resource plan is assumed to exist within the model to meet renewable energy targets. The assumed renewables are located based on known areas with potential for renewable development and can at times require conceptual transmission projects to incorporate the resources into the model.

Detailed analysis is not performed on the 20-year planning models due to the increasing levels of uncertainly looking beyond the five and 10-year horizons. The levels of uncertainly increase greatly beyond the one to five-year timeframe due to many unknown variables that may impact the transmission system in the future, such as future resource plans, state legislation, load growth, and technological advancements, amongst many others. Any single variable could have significant impacts to the model and the associated reliability results, making prudent transmission planning impossible if based on purely long-term models. Long-term models beyond 10 years into the future are best served as informative to help gain insight into potential system needs to maintain reliability. The 20-year planning models are available once required WECC non-disclosure agreements are executed, due to their source WECC planning model data.

IV. Information Verification

Finally, according to the Commission's Decision, "[t]he Utilities are reminded to provide documentation verifying all information referenced in the Joint 10-Year Transmission Plan and 20-Year Conceptual Scenario Report, including supplemental information and, as appropriate, in an accessible format via a direct link to a utility or utility-maintained website consistent with Rule 4 CCR 3627(a)(III)."[21]

The Joint Utilities have reviewed the Joint 10-Year Transmission Plan and 20-Year Conceptual Scenario Report, and have updated their Rule 3627 Ten-Year Transmission Plan to provide documentation in an accessible format via a direct link to a utility or utility maintained website. Accordingly, the Joint Utilities are concurrently providing with this Supplemental Joint Rule 3627 Report an Amended Rule 3627 Ten-Year Transmission Plan.

V. Conclusion

In conclusion, the Joint Utilities respectfully submit this Supplemental Joint Rule 3627 Report and request the Commission issue an Order finding that the Joint Utilities have satisfied their compliance obligations with respect to Rules 3625-3627.

[21] Proceeding No. 20M-0008E, Decision No. C20-0213-I, (mailed date April 7, 2020), page 9, ¶24