BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

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IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN	**)))))**	**PROCEEDING NO. 21A-____E**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF JACK W. IHLE</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

March 31, 2021

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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IN THE MATTER OF THE APPLICATION	**)**	
OF PUBLIC SERVICE COMPANY OF	**)**	
COLORADO FOR APPROVAL OF ITS	**)**	**PROCEEDING NO. 21A-____E**
2021 ELECTRIC RESOURCE PLAN AND	**)**	
CLEAN ENERGY PLAN	**)**	

DIRECT TESTIMONY AND ATTACHMENTS OF JACK W. IHLE

TABLE OF CONTENTS

SECTION **PAGE**

LIST OF ATTACHMENTS

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	**Meaning**
2020-21 RE Plan	2020-2021 Renewable Energy Compliance Plan
2021 ERP & CEP or Plan	2021 Energy Resource Plan and Clean Energy Plan
AQCC	Air Quality Control Commission
BVEM	Best Value Employment Metrics
CACJA	Clean Air-Clean Jobs Act
CDPHE	Colorado Department of Public Health and Environment
CEP	Clean Energy Plan
CEPR	Clean Energy Plan Rider
CFTI	Carbon-Free Technology Initiative
Commission	Colorado Public Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
CSG	Community Solar Garden
DER	Distributed Energy Resource
DSM	Demand-Side Management
EEI	Edison Electric Institute
ERP	Electric Resource Plan or Electric Resource Planning
GHG	Greenhouse Gas
HB 19-1261	House Bill 19-1261
ICE	Internal Combustion Engine
IPP	Independent Power Producer
ITC	Investment Tax Credit

Acronym/Defined Term	**Meaning**
kW	Kilowatt
kWh	Kilowatt-Hour
MW	Megawatt
MWh	Megawatt-Hour
NOPR	Notice of Proposed Rulemaking
Pathway Project or Colorado's Power Pathway	Colorado's Power Pathway 345 kilovolt Transmission Project
PLA	Project Labor Agreement
PPA	Power Purchase Agreement
PTC	Production Tax Credit
Public Service or Company	Public Service Company of Colorado
RAP	Resource Acquisition Period
REC	Renewable Energy Credit
RFP	Request for Proposals
RES	Renewable Energy Standard
RESA	Renewable Energy Standard Adjustment
RE Plan	Renewable Energy Compliance Plan
Roadmap	Colorado Greenhouse Gas Pollution Reduction Roadmap
RSG	Responsibly-Sourced Natural Gas
SB 07-100	Senate Bill 07-100
SB 19-236	Senate Bill 19-236
Section 123	§ 40-2-123, C.R.S.
TEP	Transportation Electrification Plan or Transportation Electrification Planning

Acronym/Defined Term	**Meaning**
VCE	Vibrant Clean Energy
XES	Xcel Energy Services Inc.
Xcel Energy	Xcel Energy Inc.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN	**) PROCEEDING NO. 21A-____E**

DIRECT TESTIMONY AND ATTACHMENTS OF JACK W. IHLE

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, AND RECOMMENDATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jack W. Ihle. My business address is 1800 Larimer Street, Denver, Colorado 80202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by Public Service Company of Colorado ("Public Service" or the "Company") as Director, Regulatory and Strategic Analysis. Public Service is a wholly-owned subsidiary of Xcel Energy Inc. ("Xcel Energy").

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THE PROCEEDING?

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As Director, Regulatory and Strategic Analysis, I am responsible for overseeing the Company's regulatory filings and strategy as they pertain to resource planning, renewable energy policy, retail product policy, electric vehicles, and other policydriven issues. A description of my qualifications, duties, and responsibilities is set forth after the conclusion of my Direct Testimony in my Statement of Qualifications.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to provide an introduction of the Company witnesses filing testimony in support of the Company's 2021 Electric Resource Plan and Clean Energy Plan ("2021 ERP & CEP" or "Plan"), as well as testimony on several policy areas, including legislative requirements created by Senate Bill 19-236 ("SB 19-236"), which strongly affects and influences this Plan. I present the statutory requirements the Company must meet under the legislation and the Commission's Electric Resource Planning ("ERP") Rules. I provide background on dispatchable natural gas resources and their relationship to GHG emissions, and also on the Boulder Franchise Agreement GHG benchmarks. I discuss Xcel Energy's overall strategy and the Company's specific efforts within this 2021 ERP & CEP to advance technologies needed to achieve carbon dioxide emission reduction targets beyond 2030 and ultimately 100 percent clean energy by 2050. Lastly, I summarize the Company's specific requests of the Commission in this Phase I 2021 ERP & CEP proceeding.

Q. HAS THE COMPANY PROVIDED A COPY OF ITS 2021 ERP & CEP AS PART OF ITS APPLICATION?

A. Yes. The Company's 2021 ERP & CEP is attached to the Direct Testimony of Company witness Ms. Alice K. Jackson, which is incorporated by reference into the Application, in three Volumes: Attachment AKJ-1 is Volume 1 of the Plan, Attachment AKJ-2 is Volume 2 of the Plan (Technical Appendix), and Attachment AKJ-3 is Volume 3 of the Plan (Request for Proposals and Model Contracts).

II. WITNESS INTRODUCTIONS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I provide a summary of the Company's witnesses also submitting Direct Testimony in this proceeding and discuss the various topics they address.

Q. PLEASE INTRODUCE THE OTHER WITNESSES SUPPORTING THE COMPANY'S FILING AND DESCRIBE THEIR AREAS OF TESTIMONY.

A. In addition to my Direct Testimony, sixteen Company witnesses are providing Direct Testimony and accompanying attachments on behalf of Public Service in this proceeding. Table JWI-D-1 below lists these witnesses along with the topics they cover in their Direct Testimonies.

Table JWI-D-1: Introduction of Company Witnesses

Witness	***Summary of Testimony***
Alice K. Jackson President of Public Service Company of Colorado	Ms. Jackson outlines the near- and long-term vision for the Company's generation system including transitioning the coal fleet, adding clean energy resources coupled with necessary flexible resources, and how the Company approached building a thoughtful and just transition. As well as how, while focusing on these key areas, the Company did not compromise on its need to deliver a reliable and affordable electric system in order to achieve Colorado's energy policy goals and the Company's own emission reduction efforts.
Brooke A. Trammell Regional Vice President, Rates and Regulatory Affairs	Ms. Trammell summarizes the policies that support the Company's proposed cost recovery mechanisms for the early retirement of certain coal generating stations that will be retired early as part of the Company's coal action plan and the incremental costs associated with the Clean Energy Plan ("CEP"). Ms. Trammell also discusses the importance of the Company's Colorado Power Pathway transmission project as a foundational component to the Company's CEP. Ms. Trammell discusses the Company's proposed framework for incorporating the Commission's stated interest in performance-based regulation into this 2021 ERP & CEP process. Ms. Trammell also discusses the need for ratemaking authorizations associated with investigating the feasibility of potential future resources with multi-year development times extending beyond this ERP. Finally, Ms. Trammell presents the expenses incurred or to be incurred by the Company in connection with this 2021 ERP & CEP.

Witness	***Summary of Testimony***
James F. Hill Director, Resource Planning	Mr. Hill summarizes the Company's resource planning process, including the foundational elements of planning: the resource acquisition period, the resource need, how a CEP is selected, the proposed coal action plan, and the difference between Phase I and Phase II of the ERP process. Mr. Hill also discusses what alternative scenarios were considered when selecting the Company's preferred plan and how those alternatives influenced the process.
Jon T. Landrum Manager, Resource Planning Analytics	Mr. Landrum discusses the Company's new modeling tool, EnCompass, that we are using for this 2021 ERP & CEP and explains its capabilities and how the functionality of the EnCompass model differs from the former Strategist model. Mr. Landrum also describes how the model runs were performed for purposes of the Company's Phase I modeling and explains several of the key inputs and assumptions that went into the model.
John T. Welch Vice President, Commercial Power Operations	Mr. Welch discusses how the Company verified that the Preferred CEP will result in reliable system operations, how generation planning ensures a reliable system, third-party standards for reliability, and how the system will need to evolve to manage greater amounts of renewable energy.
Hari Singh Principal Engineer	Mr. Singh provides an overview of the Company's transmission system and the additional investments needed to support the Company's Preferred CEP.

Witness	***Summary of Testimony***
Lauren W. Quillian Energy and Environmental Policy Manager	Ms. Quillian provides a summary of the Company's support of carbon reduction policies, its carbon reduction targets, and the Air Quality Control Commission ("AQCC")/Colorado Department of Public Health and Environment ("CDPHE")'s process for determining and verifying these emissions. Ms. Quillian also discusses other greenhouse gas ("GHG") emissions and how those emissions are accounted for.
John M. Goodenough Manager, Energy Forecasting	Mr. Goodenough summarizes the Company's base forecast for future energy sales and peak demand. He also discusses the sensitivities that provide alternative views of future sales and demand under different policy considerations.
Scott A. Watson Director, Operating Company Finance	Mr. Watson summarizes the approaches to asset recovery including accelerated depreciation, regulatory assets, and securitization. He also provides the technical analysis that supports the Company's proposed use of regulatory assets and securitization for the early retirement of certain coal generating stations.
Alex G. Trowbridge Pricing Consultant	Mr. Trowbridge provides the technical analysis of the Company's Renewable Energy Standard Adjustment ("RESA") and CEP Rider ("CEPR") cost recovery mechanisms.
Hollie J. Velasquez Horvath Senior Director, State Affairs and Community Relations	Ms. Velasquez Horvath discusses the Company's community assistance plans that support the accelerated retirement of Hayden 1 and 2 and Comanche 3.

Witness	***Summary of Testimony***
Holly L. Stanton Manager, Workforce Relations	Ms. Stanton provides a summary of the Company's workforce transition plan related to the early retirement or conversion of certain generating stations associated with the Company's coal action plan.
Kent L. Scholl Senior Resource Planning Analyst	Mr. Scholl provides a summary of the studies conducted to support the Company's ERP and CEP including the Solar and Wind Integration studies, the Effective Load Carrying Capability Study, the Coal Cycling Study, and the Flex Reserve Study.
Kevin D. Carden Director, Astrapé Consulting	Mr. Carden provides a summary of the Planning Reserve Margin study.
Richard L. Belt Director of Chemistry and Water Resources	Mr. Belt provides a summary of the impact on water usage and water rights of certain coal facilities proposed for retirement or conversion as part of the Company coal action plan.
Tara Fowler Manager, Renewable Energy Power Purchases	Ms. Fowler introduces a new model power purchase agreement ("PPA") for standalone energy storage and provides background on material changes to the model dispatchable PPA, renewable energy PPA, and solar with storage PPA.

Q. PLEASE SUMMARIZE THE COMPANY'S REQUESTED APPROVALS IN THIS PROCEEDING?

A. In Table JWI-D-2 below, I provide the approvals and findings the Company is requesting as part of this 2021 ERP & CEP proceeding, along with the primary supporting witnesses for the various requests.

Table JWI-D-2: Summary of Requested Approvals and Findings

Requested Approval or Finding	***Primary Sponsoring Witness(es)***
Approval of our 2021 ERP & CEP (Attachments AKJ-1 through AKJ-3), inclusive of the sub-approvals set forth in this table.	*Alice Jackson*
Approval of the Company's proposed Phase II all-source competitive acquisition and bid evaluation process to acquire generation resources to meet the Company's resource needs in this proceeding (sub-approval).	*James Hill*
Approval of the Requests for Proposals ("RFPs") and model contracts set forth in Volume 3 (Attachment AKJ-3) (sub-approval).	*Tara Fowler* *Kent Scholl*
Approval of the modeling inputs, assumptions, and methodologies included in the Company's Phase I filing (sub-approval).	*Rich Belt* *John Goodenough* *James Hill* *Jon Landrum* *Holly Stanton* *Hollie Velasquez-Horvath* *Alexander Trowbridge* *John Welch*

Requested Approval or Finding	***Primary Sponsoring Witness(es)***
Approval of the updated studies to be used in the Phase II bid evaluation process, including the: Planning Reserve Margin Study; Wind and Solar Integration Study; Effective Load Carrying Capability Study; and Flex Reserve Study and Supplemental Flex Reserve Study (sub-approval).	*Kevin Carden* *Kent Scholl*
Approval of the Company's preferred coal transitions, including approval to: accelerate the retirement of Hayden 2 to 2027 and Hayden 1 to 2028 consistent with the agreement reached among the joint owners; accelerate the retirement of Craig 2 to September 30, 2028 consistent with the agreement reached among the joint owners; convert Pawnee from coal to natural gas by the end of 2028; and reduce operations of Comanche 3 to an approximately 33 percent capacity factor beginning in 2030 and accelerate retirement of the unit to 2040 (sub-approval).	*Alice Jackson* *James Hill*
A finding that coal cycling costs are not a necessary model input for the Phase II bid evaluation (sub-approval).	*Kent Scholl*
Approval of the regulatory asset recovery method for: Craig 2; Hayden 1; Hayden 2; and the retired portion of Pawnee.	*Scott Watson*

Requested Approval or Finding	***Primary Sponsoring Witness(es)***
A finding that the Company's plan to securitize the costs associated with the accelerated retirement of Comanche 3 is reasonable and in the public interest to enable the Company to begin a series of actions over the next two decades to effectuate the securitized refinancing, which will involve subsequent regulatory filings and Commission approvals.	*Brooke Trammell*
Approval of the proposed "time fence" and associated locking of certain resources consistent with the RESA, as well as approval of the recording of incremental costs based upon a calculation of the average avoided cost determined by resource type as determined in this Phase I proceeding.	*Alexander Trowbridge*
Approval to initiate the CEPR after the issuance of the Phase II decision in this proceeding.	*Brooke Trammell*
Approval to track and defer costs incurred in association with preparing and litigating this proceeding into a non-intrest-bearing regulatory asset to be reviewed for recovery purposes in a future rate proceeding.	*Brooke Trammell*
Approval of the proposed Emissions Reduction Performance Incentive Mechanism.	*Brooke Trammell*

Requested Approval or Finding	***Primary Sponsoring Witness(es)***
A finding that the Commission recognizes the financial implications of adding stand-alone battery storage resources in this ERP and accordingly authorizes future rate base inclusion of capital leases as necessary to effectuate the acquisition of certain stand-alone battery resources. Alternatively, the Company requests the Commission affirmatively state that it will not accept bids for unrestricted stand-alone battery storage resources in the competitive solicitation.	*Brooke Trammell*
A finding that the Commission encourages the Company to investigate the feasibility of certain long-lead time generation resources to achieve carbon reductions beyond 2030 and authorize certain ratemaking treatment for associated costs.	*Brooke Trammell*

III. LEGISLATIVE AND REGULATORY BACKGROUND

A. Background

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. The purpose of this section of my Direct Testimony is to briefly address the interplay between SB 19-236 and House Bill 19-1261 ("HB 19-1261"), both passed by the General Assembly and signed into law by Governor Polis as part of the historic 2019 legislative session, as well as the regulatory strategies outlined in the final Colorado Greenhouse Gas Pollution Reduction Roadmap ("Roadmap"), provided as Attachment AKJ-4 to the Direct Testimony of Company witness Ms. Jackson. I also address the Commission's ongoing proceeding concerning pending ERP rules (Proceeding No. 19R-0096E).

The Roadmap represents the State of Colorado's template for its deliberative development of sector-specific approaches toward the achievement of economy-wide emission reductions of 50 percent by 2030 and 90 percent by 2050, consistent with the objectives of HB 19-1261. The State of Colorado has taken its own approach to developing a regulatory architecture to advance emission reductions across the economy, by pursuing sector-specific emission regulations that take into account the unique nature of the diverse segments of the economy regulated under any program. In many ways, this 2021 ERP & CEP is the centerpiece of these broader efforts—it will require contributions and changes from many, but the architecture developed by the General Assembly was built to have the power sector lead the way in the State's clean energy transition. Our preferred plan shows we are prepared to meet this charge.

Q. PLEASE PROVIDE SOME BACKGROUND ON EFFORTS IN THE STATE OF COLORADO TO REDUCE EMISSIONS FROM THE POWER SECTOR.

A. The State of Colorado and Public Service are on one of the most aggressive trajectories for power sector emission reductions in the United States. The State of Colorado was an early mover on clean energy adoption, starting with the passage of Amendment 37 in 2004, followed by the Clean Air-Clean Jobs Act ("CACJA") in 2010. These early legislative actions fostered a market for clean energy in Colorado that has advanced the state toward an ever-cleaner power supply. And while the State's energy policy has progressed over time, it has consistently relied upon the regulated utility model to advance environmental and clean energy objectives.

Public Service has been there every step of the way, continuously advancing proposals to reduce emissions and fulfill its obligation to serve. In one recent prominent example from the 2016 ERP, the Company worked with a large and diverse set of stakeholders to develop the Colorado Energy Plan, resulting in the retirement of 660 megawatts ("MW") of coal generation and approval of a replacement portfolio anchored by over 2,000 MW of clean energy and embedded storage. The Colorado Energy Plan, which the Commission approved in September 2018, will take Public Service's system to an estimated 55 percent delivered renewable energy by 2025.

As it turns out, the Commission's decision on the Colorado Energy Plan was just the beginning. On December 4, 2018, Xcel Energy continued its clean energy leadership when we announced a first-of-its-kind commitment, pledging to reduce emissions 80 percent from 2005 levels by 2030 and deliver 100 percent carbon-free electricity to customers by 2050. Our leadership on this issue spurred similar commitments across the utility sector nationally, with over twenty utilities having since adopted carbon-free electricity pledges. Shortly after Xcel Energy's announcement, the Colorado General Assembly embarked on its 2019 legislative session, which made history from a clean energy and climate policy perspective with two landmark bills. HB 19-1261 set economywide emission reduction goals, while SB 19-236 directed large regulated utilities to reduce emissions by 80 percent from 2005 levels by 2030 and 100 percent by 2050 using Colorado's tried and true ERP process. Together, these bills created Colorado's first-ever comprehensive and aggressive climate law.

B. <u>2019 Legislation and Subsequent Policy</u>

Q. PLEASE PROVIDE SOME BRIEF BACKGROUND ON SB 19-236 AND HB 19-1261.

A. These two bills are both directed at emission reductions, with SB 19-236 focused specifically on the power sector and HB 19-1261 focused on emission reductions statewide. HB 19-1261 was introduced in the General Assembly on March 21, 2019, and passed on May 1, 2019. SB 19-236 moved forward on a similar timetable; it was introduced on April 9, 2019, and passed on May 3, 2019. Both bills were signed into law by Governor Jared Polis on May 30, 2019.

Q. WHAT GHG EMISSION REDUCTION GOALS DOES HB 19-1261 PUT IN PLACE?

A. HB 19-1261 establishes economywide emission reduction goals in 2025, 2030, and 2050, respectively, all based on a 2005 emission baseline. The goals are progressively more stringent, with a 26 percent GHG emission reduction from 2005 levels required by 2025, a 50 percent GHG emission reduction from 2005 levels required by 2030, and a 90 percent GHG emission reduction from 2005 levels required by 2050.[1]

Q. WHAT EMISSION REDUCTION GOALS ARE ESTABLISHED BY SB 19-236?

A. SB 19-236 is specific to the power sector with emission reduction objectives that align with the voluntary emission reduction goals announced by the Company on December 4, 2018. The bill is designed to work in concert with the ERP process and establishes “clean energy targets,” also based on a 2005 baseline, of an 80 percent emission reduction by 2030 and 100 percent clean energy by 2050. The legislation requires Public Service to file a CEP as part of its next ERP—hence this 2021 ERP & CEP—to meet or exceed the 80 percent clean energy target. If the Commission approves a CEP that achieves an emission reduction of 75 percent from 2005 levels, then Public Service is provided with a “safe harbor” from any additional regulations developed by the AQCC that require emission reductions from the power sector through 2030.

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[1] § 25-7-102(2)(g), C.R.S.

Q. IS PUBLIC SERVICE THE ONLY UTILITY REQUIRED TO FILE A CEP?

A. Yes. However, certain other utilities may file a CEP on a voluntary basis and also obtain the benefit of the safe harbor.

Q. HOW DO THESE TWO BILLS WORK TOGETHER IN YOUR OPINION?

A. I am not a lawyer, but to me the answer is simple. To achieve the economywide emission reduction goals of HB 19-1261, the General Assembly recognized it would require the continued leadership of the power sector. Accordingly, if utilities are willing and able to advance plans that achieve a 75 percent emission reduction by 2030 from 2005 levels, they are provided with the benefit of a safe harbor from additional AQCC or other emission reduction regulations through 2030. This safe harbor provides valuable regulatory certainty for the utilities filing CEPs and an incentive to bring forward meaningful and timely emission reduction efforts.

I also think it is important to consider the bigger climate picture here. To that point, the goals established in SB 19-236 are in line with climate science. In setting our own ambitious Xcel Energy goal in 2018 of 80 percent emission reductions by 2030, we collaborated with the Intergovernmental Panel on Climate Change's lead author at the University of Denver to understand how our trajectory aligned with the climate science.[2] Based on analysis of climate scenarios that met both the 2-degree and 1.5-degree temperature rise outcomes, the trajectory of 80

[2] *See Xcel Energy carbon emissions targets and limiting warming to less than 2 degrees C* (Dec. 31, 2018), available at https://www.xcelenergy.com/staticfiles/xe/PDF/University%20of%20Denver%20analysis%20of%20Xcel%20Energy%20carbon%20goals.pdf.

percent reductions by 2030 and 100 percent by 2050 is consistent with achieving these temperature goals in a developed economy.

Q. WHERE DOES THE ROADMAP FIT IN?

A. The General Assembly has established a monumental task for the State of Colorado to reduce emissions. The Roadmap is a vision to get there, but—as I will explain—it relies heavily on the power sector. The Roadmap was finalized by the State of Colorado on January 14, 2021 following a stakeholder process. The Roadmap is an expansive document that contains numerous "Near Term Actions to Reduce GHG Pollution" across key sectors of the Colorado economy, including in part: electricity; transportation; residential, commercial, and industrial fuel use; oil and gas; and natural and working lands.[3] Simply put, emission reductions from the power sector are a lynchpin to put the State of Colorado on the path it needs to be on to achieve the economywide emission reduction goals of HB 19-1261.

Q. PLEASE EXPLAIN.

A. The Roadmap notes that "the largest single opportunity for near term reductions is in the electricity sector, where the Roadmap is targeting an 80% reduction, or 32 million tons, below 2005 emissions levels by 2030."[4] It further provides that "[t]he combination of a 2030 GHG pollution reduction target and the potential for any utility to file a Clean Energy Plan provides an important framework to implement

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[3] Attachment AKJ-4, at 29-34 (Table 1).

[4] Attachment AKJ-4, at 88.

enforceable emissions reductions."[5] The emission reduction trajectory outlined in the Roadmap relies on eligible utilities—not just Public Service—filing resource plans that meet the 80 percent clean energy target of SB 19-236. The Roadmap states that "[t]he six utilities that operate more than 99 percent of the state's fossil-fired generation, Xcel Energy, Tri-State Generation and Transmission, Colorado Springs Utilities, Platte River Power Authority, Black Hills Energy, and Holy Cross Energy, have already committed to resource plans that meet or exceed an 80% GHG reduction by 2030."[6] Finally, it states that "[t]he state is not proposing to require reductions greater than 80% by 2030 across the board, although it is hopeful that the 80% reductions might be reached earlier or exceeded by 2030."[7]

Q. WHAT ARE YOUR TAKEAWAYS FROM THIS DISCUSSION IN THE ROADMAP?

A. My main takeaway is that the State of Colorado is relying on what we have termed a "down-payment" of emission reductions from the power sector to advance the State of Colorado towards its broader emission reduction goals. And this is where the 2021 ERP & CEP fits in. The power sector and energy regulatory space are evolving at a rapid pace, and utilities have been challenged to meet aggressive emission reduction goals.

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[5] Attachment AKJ-4, at 91.

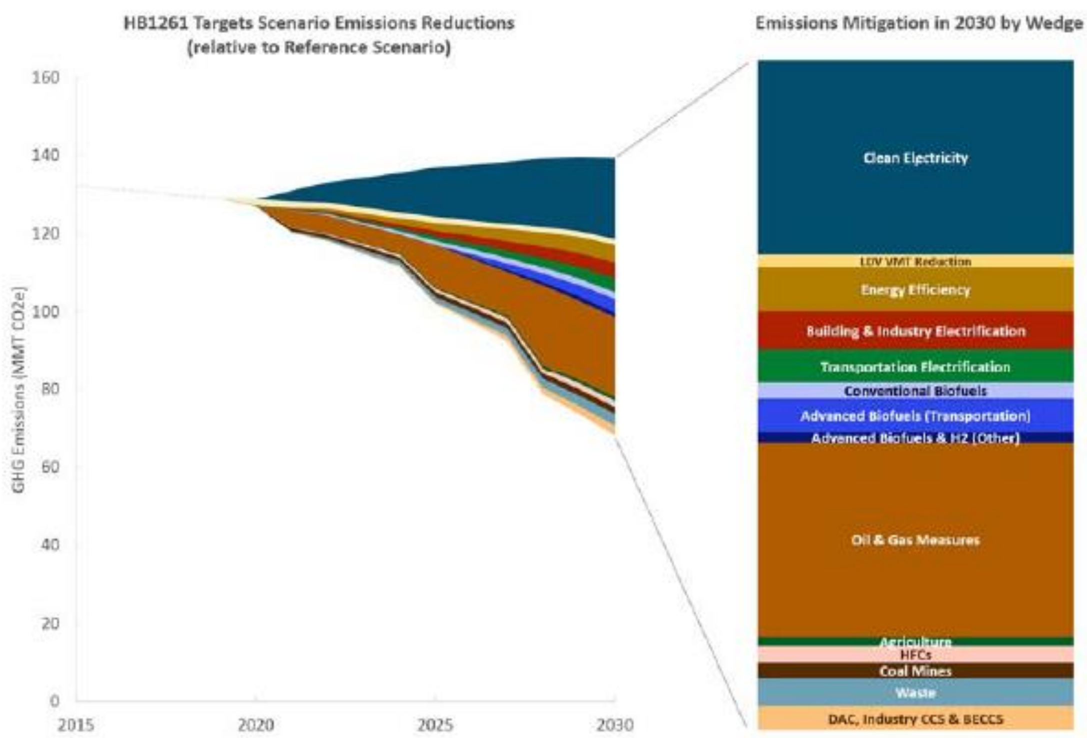
[6] Attachment AKJ-4, at 79.

[7] Attachment AKJ-4, at 79.

Q. HOW QUICKLY AND HOW SIGNIFICANTLY IS THE ROADMAP DEPENDING ON THE POWER SECTOR TO ADVANCE EMISSION REDUCTIONS?

A. Both quickly and aggressively. Figure 3 of the Roadmap,[8] excerpted below as Figure JWI-D-1, illustrates this quite well.

Figure JWI-D-1: Roadmap Emission Reductions by Sector



Q. PLEASE EXPLAIN WHAT THIS FIGURE SHOWS IN THE ROADMAP.

A. It shows that a significant portion of the reductions necessary to meet the 2030 emission reduction goals of HB 19-1261 are dependent on CEPs filed pursuant to SB 19-236. The Roadmap recognizes as much, stating that "[a]chieving the 2030

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[8] Attachment AKJ-4, at 21.

goals will rely on deep reductions in pollution from electricity generation by continuing the transition to renewable energy ….”[9] The Roadmap's narrative and analyses build out the reliance on the power sector between now and 2030 to meet the State of Colorado's energy policy objectives. The Roadmap also recognizes that "[o]ne important benefit flowing from the rapid transition towards clean electricity is that it magnifies the pollution reduction, public health, and other benefits of electrification in other sectors, such as cars and buildings."[10]

Q. HOW DO THESE BILLS FIT INTO THE HISTORICAL CONTEXT OF EMISSION REDUCTIONS FROM THE POWER SECTOR?

A. Our December 2018 announcement and the historical climate package that followed set the stage for the latest act in the clean energy transition. While Figure JWI-D-1 and the Roadmap are forward-looking, historical context around the performance of the power sector in achieving emission reductions is also helpful. From 2005 to 2020, working collaboratively with this Commission, Public Service reduced carbon dioxide emissions by 46 percent. No other sector, and no other Colorado business I am aware of, can demonstrate the track record of emissions reduction in total tons that Public Service can. I draw attention to this point for two reasons. It is critical for the State of Colorado to recognize that our electric customers have long been supporting the biggest strides in emission reductions in

[9] Attachment AKJ-4, at 22.

[10] Attachment AKJ-4, at 174.

the state, and it illustrates that the Roadmap's focus on the power sector is well-placed.

C. 2019 Legislation and Our 2021 ERP & CEP

Q. WHAT IS THE PROCESS FOR SUBMISSION AND APPROVAL OF A CEP?

A. Utilities subject to the SB 19-236 requirement must include in their first ERP filed after January 1, 2020 a CEP that sets forth a plan of actions and investments that are projected to meet the 2030 carbon reduction goal while maintaining an affordable, reliable, and clean electric system. The ERP must include a Resource Acquisition Period ("RAP") that extends through 2030. Further, it must distinguish between two sets of resources and actions: (1) those needed to meet customer demand during the RAP; and (2) those needed to meet the 2030 clean energy target. Activities detailed in the CEP may include retirement of existing facilities, changes in system operations, or any other necessary actions. The CEP must also describe the effect of the plan on the safety, reliability, renewable energy integration, and resilience of electric service in the State.

Q. WHAT ARE THE PARAMETERS SET BY SB 19-236 CONCERNING THE RESOURCE ACQUISITION PROCESS?

A. SB 19-236 requires the use of a competitive bidding process that has long been a part of resource planning in Colorado to fill the cumulative resource needs of the ERP and CEP. However, the legislation also provides a 50 percent ownership target for the utility for new clean energy resources acquired in the plan if the Commission finds that the cost of utility ownership comes at a reasonable cost and rate impact. This provision recognizes that utilities would be bringing forward assets for retirement that have received previous Commission approval for cost recovery, and—as explained by Company witness Ms. Jackson—it acknowledges the importance of maintaining a financially healthy utility throughout the clean energy transition. The achievement of this ownership target will not be specifically designated in the Company's preferred plan or other portfolios in this Phase I filing, but will be addressed in proposed portfolios assembled from actual bids under Phase II (although utility ownership is modeled on a generic basis at a 50 percent level). This codified ownership split is similar to a provision that existed in the multi-party Stipulation developed in 2018, resulting in the Company's historic Colorado Energy Plan.[11]

Q. WHAT ARE THE REQUIREMENTS FOR THE CEP TO ADDRESS THE RELIABILITY AND RESILIENCE OF THE ELECTRIC SYSTEM?

A. A CEP filing must describe the effect of the actions and investments included in the plan on the safety, reliability, renewable energy integration, and resilience of electric service in the State of Colorado.[12] In approving the plan, the Commission must consider the CEP's impact on reliability and resilience, and may not approve a plan that does not protect system reliability. The Commission may, on its own motion or upon the filing of an application by the utility, amend an approved CEP if necessary to ensure the reliability and resilience of the electric system, and may also direct the utility to report to the Commission on the reliability and resiliency of

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[11] *See* Stipulation filed on August 29, 2017 in Proceeding No. 16A-0396E.

[12] § 40-2-125.5(4)(a)(V), C.R.S.

the electric system to ensure that there are no adverse impacts from the CEP. I address resilience at more length later in my Direct Testimony, and Company witness Mr. Welch also addresses the CEP's impacts on reliability and resilience in his Direct Testimony.

Q. HOW IS THE COMPANY'S PROPOSAL REQUIRED TO CONSIDER CARBON COSTS?

A. Under § 40-3.2-106, C.R.S., utilities are required to consider the cost of carbon dioxide emissions when determining the cost, benefit, or net present value of a plan or proposal in an ERP or certain other proceedings. In an ERP proceeding, utilities must model an optimization of a base case portfolio of resources using the "social cost of carbon dioxide emissions," with the cost applied to all existing and any new resources evaluated or proposed. Beginning in 2020, the Commission was directed to use a social cost of carbon dioxide emissions based on the most recent assessment of the social cost of carbon developed by the federal government, but in any case starting at no less than $46 per short ton, modified based on escalation rates contained in the federal Interagency Working Group on the Social Cost of Greenhouse Gases' 2016 Technical Support Document. In addition to the base case modeled using this dollar amount for the cost of carbon, utilities may also propose alternative optimized portfolios that use different levels of costs for carbon dioxide. Utilities must also present a calculation of the net present value of revenue requirements for the resources in each optimized portfolio both including and excluding the social cost of carbon emissions, as well as a net present value calculation of the total cost of carbon dioxide emissions for each portfolio using the social cost of carbon emissions. In approving the ERP, the statute directs the Commission to consider the net present value of the cost of carbon dioxide emissions, the net present value of revenue requirements that would be incurred by the utility for implementing the portfolio, and other factors the Commission deems relevant.

Q. DOES THE CEP LEGISLATION ADDRESS THE INCREMENTAL COSTS OF RESOURCES ACQUIRED AS PART OF A UTILITY'S CEP?

A. Yes. A CEP filing must set forth the projected cost of its implementation and anticipated reductions in carbon dioxide and other emissions. SB 19-236 establishes a funding mechanism for costs associated with a CEP while limiting the retail rate impact to 1.5 percent of a customer's total electric bill annually. Utilities are directed to collect revenues through the CEPR, which is assessed on a percentage basis on all retail customer bills. The CEPR is to be used to cover the costs of a utility's CEP capital investments and operating and related expenses, with certain exceptions: fuel and transmission costs; costs associated with capital investments needed to satisfy the resource need identified in the ERP without the CEP; incremental costs of eligible energy resources that are recovered through the RESA; and the incremental costs of any clean energy resources and directly related interconnection facilities that are recovered with funds collected under the RESA in accordance with the Commission's approval in the CEP proceeding. The CEPR may be established as early as the year following the approval of a CEP by the Commission, and the utility may propose a commencement date and level that does not exceed the maximum retail rate impact for approval by the Commission. The CEPR is designed to afford the utility cost recovery treatment, with a final reconciliation in the first rate case following the final implementation of the CEP, at which time remaining costs and savings are to be incorporated into base rates.

Q. WHAT ABOUT THE BASE LEVEL COSTS OF THE ERP?

A. I consider base level costs to be those costs associated with fulfilling this ERP as would have progressed without the CEP overlay. Those costs, generally identified in the reference case portfolio, are recovered through normal utility rate recovery. In this instance, that would mean costs associated with eligible energy resources would go through the Electric Commodity Adjustment or the RESA, transmission costs would be recovered through the Transmission Cost Adjustment, and other costs would be evaluated and recovered through a base rate case unless otherwise provided for in another Commission decision. This is addressed in more detail by Company witnesses Ms. Trammell and Mr. Trowbridge.

Q. WHAT ROLE DOES THE RESA PLAY IN A UTILITY'S CEP?

A. If a utility is meeting the minimum amount of energy required from eligible energy resources pursuant to the requirements of § 40-2-124(1)(c), C.R.S., the utility may propose to use up to half of the funds collected annually from the RESA, as well as any accrued funds, to recover the incremental cost of any clean energy resources and their directly related interconnection facilities.

Q. DOES SB19-236 ADDRESS THE ROLE OF RENEWABLE ENERGY CREDITS ("RECs")?

A. Yes, a utility is required to retire RECs in the year they are generated by any eligible energy resources used to comply with the clean energy targets. The Company interprets this part of the statute to mean that it must retire, or cause to be retired, RECs from eligible energy resources in the year generated starting in 2030, the year of the first compliance requirement of the section. The Company understands that the Commission seeks comment and analysis as to when the current year REC retirement provision applies, and the Company's position is that it applies in 2030 based on the plain language of the statute. I am attaching as Attachment JWI-1 a legal analysis previously filed with the Commission in Proceeding No. 19R-0096E in support of that interpretation.

Q. DID SB 19-236 CREATE OTHER FINANCIAL TOOLS THAT MAY SERVE A ROLE IN THE TRANSITION TO A LOW-CARBON ELECTRIC SYSTEM?

A. Yes, SB 19-236 includes the "Colorado Energy Impact Bond Act," which creates a new financial mechanism that offers utilities the ability to securitize the costs associated with retiring an electric generating station in the state. This section of SB 19-236 is addressed in more detail by Company witnesses Ms. Trammell and Mr. Watson.

Q. DOES THE STATUTE PROVIDE GUIDANCE FOR HOW TO ADDRESS THE IMPACTS THAT WORKERS AND COMMUNITIES WILL EXPERIENCE AS A RESULT OF THE TRANSITION TO A CLEAN ELECTRICITY SYSTEM IN COLORADO?

A. Yes. If a CEP includes accelerated retirement of existing generation facilities, it should include workforce transition and community assistance plans. SB 19-236 also provides that the utility may propose a cost recovery mechanism to recover prudently incurred costs, while giving due consideration to the impact on low-income customers. These plans are addressed in more detail by Company witnesses Ms. Jackson, Ms. Stanton, and Ms. Velasquez Horvath. They address the status of the plans and potential future post-ERP filings related to them.

Q. IN ADDITION TO THE WORKFORCE TRANSITION PLAN, ARE THERE OTHER REQUIREMENTS CONCERNING LABOR IN SB 19-236?

A. Yes. SB 19-236 made amendments to § 40-2-129, C.R.S., which established a framework that holds utilities and non-utility bidders to similar standards when it comes to providing best value employment metrics ("BVEM") information. Specifically, the statute requires utilities to obtain and provide to the Commission the BVEM documentation in response to the four codified metrics.[13] When a utility

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[13] The BVEM include: (1) the availability of training programs, including training through apprenticeship programs registered with the United States department of labor, labor's office of apprenticeship and training or by state apprenticeship councils recognized by that office; (2) employment of Colorado labor as compared to importation of out-of-state workers; (3) long-term career opportunities; and (4) industry-standard wages, health care, and pension benefits.

proposes to construct new generation facilities of its own, the utility is required to provide similar information to the Commission. To ensure that the BVEM information provided by either a bidder or the utility is substantive, § 40-2-129, C.R.S., as amended by SB 19-236, requires: (1) provision of the BVEM documentation; or, (2) in the alternative, certification of compliance with objective BVEM performance standards set forth in the solicitation document. The Commission may waive the requirements of (1) and (2) where a Project Labor Agreement ("PLA") is utilized (similar to the contracting structures that the Company has used and advanced in its Community Resiliency Initiative, Electric Vehicle Infrastructure, and Renewable Energy Compliance Plan ("RE Plan") proceedings). This statutory framework was designed to remedy the challenges independent power producers ("IPPs") have expressed with providing robust and detailed BVEM documentation, by providing alternative pathways to comply with BVEM requirements in allowing IPPs and utilities to either certify compliance with objective BVEM standards, or commit to the use of a PLA in lieu of providing BVEM documentation. These options ensure that IPPs and utilities are on similar footing when it comes to meeting BVEM requirements in the context of a resource acquisition process. Company witnesses Ms. Jackson and Mr. Hill also address BVEM and its role in the Phase II bid evaluation in their Direct Testimony.

Q. WHAT ARE THE CRITERIA THAT THE COMMISSION MUST CONSIDER IN EVALUATING AND APPROVING A CEP?

A. The Commission must approve a CEP if it finds the plan to be in the public interest and consistent with the target of reducing the utility's emissions from electric sales to customers 80 percent below 2005 levels by 2030. The Commission may modify a plan if the modification is necessary to ensure that the plan is in the public interest. In evaluating the public interest, the Commission is directed to consider:

- Reductions in carbon dioxide and other emissions that will be achieved through the CEP and the environmental and health benefits of those reductions;
- The feasibility of the CEP and its impact on the reliability and resilience of the electric system; and
- Whether the CEP will result in a reasonable cost to customers.

If the Commission finds that the proposed CEP is not in the public interest or modifies the plan, utilities may choose to submit an amended plan to the Commission for approval in lieu of having no plan or implementing the modified plan. Commission approval is required for a CEP to be effective.

Q. IS THE PURPOSE OF THE ERP PROCESS CHANGING OVER TIME?

A. Yes, I believe that it is. Though I discussed several requirements stemming from SB 19-236 above, I believe the 80 percent emissions reduction requirement is the defining one for this ERP. That requirement sets the context for many of the other requirements. That requirement also represents the evolution of resource planning. Resource planning has traditionally been a process by which to plan the system to ensure that adequate new generation resources are developed to reliably meet demand. This is of course an essential process, and is itself complex and challenging. With the addition of variable energy resources such as wind and solar over the past decade-plus, this complexity has compounded. Furthermore, now that we areadding historic quantities of these resources, our simpler resource planning look at the peak hour of the year has transitioned into the need to examine and evaluate all 8,760 hours in a year because of the variable nature of resource availability. But increasingly, we are also asked to perform two related additional tasks.

The first task is to plan to achieve emission reductions. Emission reductions have been an objective for several of the Company's recent resource plans, but the 80 percent reduction requirement has made the objective more explicit, more firm, and more challenging in this 2021 ERP & CEP. While the Company and Commission have used carbon pricing as a factor in resource planning and have certainly considered and approved new resources through the lens of reducing carbon dioxide and other emissions, the emissions reduction objective was never a firm target or constraint in building portfolios. Now it is—SB 19-236 takes the next step and creates the 80 percent reduction as a firm target.

The second task is to evaluate existing generating resources for retirement or changed operation. The Company has previously done this evaluation in a significant way in the emission reduction plan that resulted from the 2010 CACJA legislation, and later in the Colorado Energy Plan that emerged from the 2016 ERP, which ultimately retired two coal units, as described above. In this ERP, we are taking on the existing unit evaluation task at an even broader scale, by considering the future pathways for over 1,700 MW of existing coal-fired generation at four different coal-fired generating plants (Craig, Hayden, Pawnee and Comanche) in three different regions of Colorado.

D. Commission Rules

Q. DOES THE COMPANY DESCRIBE IN ITS PLAN HOW IT COMPLIES WITH COMMISSION RULES IN FILING THIS ERP?

A. Yes. In Volume 2 of this filing, we provide extensive discussion of how this ERP filing comports with existing Commission ERP rules.

Q. HAS THE COMMISSION UNDERTAKEN A PROCESS TO DEVELOP NEW ERP RULES?

A. Yes. On February 27, 2019, the Commission issued a Notice of Proposed Rulemaking ("NOPR") in Proceeding No. 19R-0096E to amend several areas of the Commission's Rules Regulating Electric Utilities, including amendments to the ERP Rules. The Company and many other stakeholders filed numerous rounds of comments and participated in several hearings over the course of the rulemaking proceeding.

Q. DID PROCEEDING NO. 19R-0096E RESULT IN FINAL REVISED ERP RULES PRIOR TO THE COMPANY FILING ITS 2021 ERP & CEP?

A. No. At the Commissioners' Weekly Meeting on March 24, 2021, the Commission discussed the rulemaking at length and decided to not adopt new rules as a result of the proceeding. The Commission discussed numerous issues associated with the rulemaking and discussed options for future consideration of those issues; however, the Commissioners expressed interest in spending time on the language to be crafted in the decision on the various components, and no decision has been issued as of the submittal of this testimony. Therefore, the Company developed its ERP in compliance with the existing rules currently in effect as detailed in Volume 2 of its 2021 ERP & CEP (Attachment AKJ-2).

Q. HAS THE COMPANY PROVIDED INFORMATION OR ANALYSES THAT GO BEYOND THE EXISTING RULES IN ITS DEVELOPMENT OF THIS ERP FILING?

A. Yes. First, as described at length above, SB 19-236 created multiple new resource planning requirements. Also, based on the Company's participation in the rulemaking process over the course of Proceeding No. 19R-0096E, as well as in the preceding Miscellaneous docket, (Proceeding No. 17M-0694E), we believe there are some issues that have fairly strong stakeholder interest and/or unopposed support. The Company has proactively provided additional or supplemental information above and beyond the existing rules to address certain issues discussed in previously proposed rules that we felt were of particular interest to the Commission and stakeholders.

Q. CAN YOU PLEASE DESCRIBE WHICH ISSUES FOUND IN PREVIOUSLY PROPOSED RULES THE COMPANY HAS ADDRESSED IN THIS ERP FILING?

A. Yes. As described in more detail in Volume 2 of our Plan, the Company has addressed information regarding the following issues found in previously proposed rules:[14]

- Assessment of potential cost-effective early retirements of utility-owned resources (Proposed Rule 3604(l));

[14] *See* Decision No. C20-0207-I in Proceeding No. 19R-0096E (mailed Apr. 2, 2020), including the proposed rules in legislative (i.e., strikeout/underline) format (Attachment A) and final format (Attachment B).

- Forecast inputs regarding demand side resources, distributed energy resources, transportation electrification, and non-transportation beneficial electrification (Proposed Rules 3606(b)(I)-(II));

- Benchmarking for the purpose of identifying existing resources that potentially are not performing cost-effectively as compared to other resources available in the market (Proposed Rule 3607(c));

- Ancillary services assessment of existing resources (Proposed Rule 3607(d)); and

- Best value employment metrics information details (Proposed Rule 3613).

IV. EXTERNAL ANALYSIS OF COLORADO'S POWER SECTOR CLEAN ENERGY TRANSITION

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I present a summary and discussion of several studies considering the pathways by which the State of Colorado can achieve its emissions reductions, with a review of the resulting impact on the electric generation sector.

Q. HAVE THERE BEEN EXTERNAL STUDIES RELEVANT TO UNDERSTANDING THIS 2021 ERP & CEP AND THE COMPANY'S PREFERRED PLAN?

A. Yes. Many consulting, research, analysis and academic organizations have evaluated how the U.S. and the State of Colorado can transform to an economy that relies on lower carbon emitting resources for energy needs. Some of these organizations include academic institutions and non-governmental organizations like Princeton University or the National Academy of Sciences, as well as private consulting companies like MJ Bradley, E3, and Vibrant Clean Energy ("VCE"). Some of the analyses are conducted to study government environmental policy and its outcomes, and some are to study the opportunities for specific technologies in emission constrained scenarios.

Q. HOW DO THESE STUDIES EVALUATE EMISSION REDUCTIONS AND HOW TO ACHIEVE THEM?

A. Most of the recently published studies rely on a combination of computer modeling that considers electric capacity expansion with constraints, like the EnCompass system used in this 2021 ERP & CEP, and post processing or spreadsheet models to compare or optimize results. Several of the recently released studies rely on the same modeling tools, such as the PATHWAYS capacity planning model and the RIO optimization model, but with the analysis conducted by different organizations and with different assumptions.[15]

Q. HAVE ANY OF THESE CONSULTING OR ANALYSIS GROUPS CONSIDERED COLORADO SPECIFICALLY?

A. Yes. In Attachment JWI-2 I offer a summary table of five recent studies of Colorado's electric supply and overall economy that offer their own evaluations and recommendations for carbon emissions reductions. The five studies included have all been conducted by consulting companies for government, environmental non-profit, or private company use, but released for public consideration in energy policy decisionmaking.

Q. WHAT DO THE MODELS CONSIDERING ONLY THE STATE OF COLORADO CONCLUDE?

A. When reviewing the model-based results for achieving Colorado's emissions reduction goals, they all significantly expand renewable energy and retire coal plants either as indicated by utility commitments, or through optimization of costs and emissions decreases. Coal retirements generally follow the degree of emissions reduction. All five studies reduce Colorado power sector emissions

[15] Economy-wide GHG emissions modeling frequently uses two interdependent models: (1) an end use consumption model (e.g. PATHWAYS, EnergyPATHWAYS) which simulates demand in sectors like electricity, transportation, buildings, etc. under various policy and economic scenarios; and (2) a granular electric power generation capacity expansion model (e.g. RESOLVE, RIO, Wis:dom) which uses end use consumption (i.e., MW of peak demand and megawatt-hours ("MWh") of energy) as an input to select an optimal mix of incremental generation and storage resources and generation retirements.

significantly, by anywhere from 37 percent to 98 percent. All five studies also include continued use of gas-fired generation, to varying degrees.

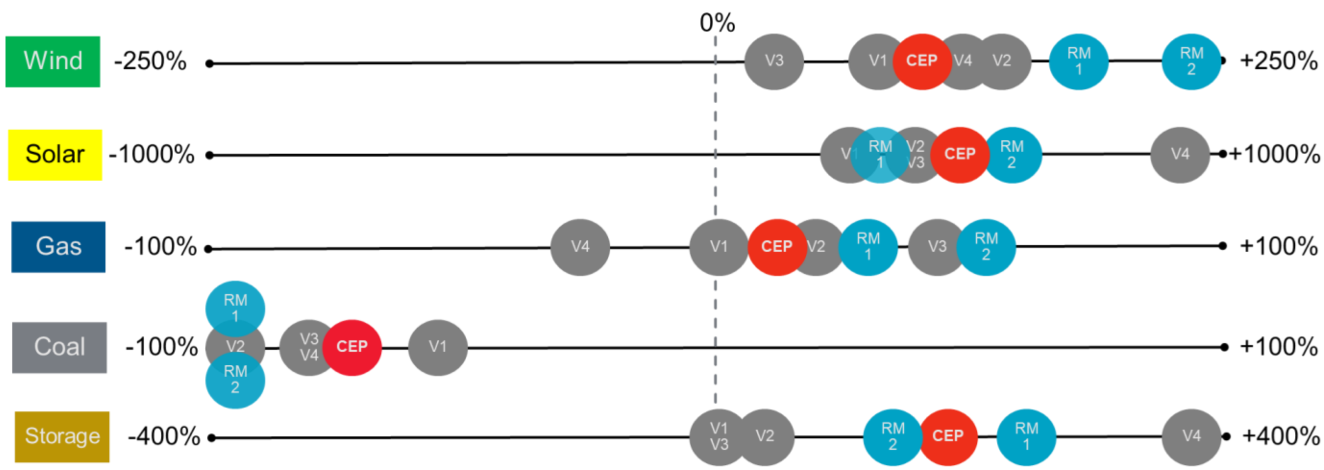
Q. ARE ALL THE STUDIES EQUALLY USEFUL BENCHMARKS FOR CONSIDERING THIS 2021 ERP & CEP?

A. The studies vary in their analytical complexity and in results available. There are also variations in how reliability and power market dynamics are considered in all of these studies. The MJ Bradley studied sponsored by Environmental Defense Fund is an economywide analysis that does not rely on or provide detailed power sector results for comparison. The NRDC/Gridlab study does not provide full data for comparison to the CEP, and also appears to model a significant degree of power imports into Colorado at levels beyond what we model for Public Service, so it was not clear that the results were comparable to the CEP. Also, because all these studies are statewide, none apply directly or specifically to Public Service.

Q. WHICH STUDIES ARE MOST USEFUL FOR DISCUSSING THE 2021 ERP & CEP?

A. Based on our research to date, I believe the Roadmap and its underlying power sector analysis, and the two studies conducted by VCE for Community Energy provide the most useful comparisons to the Company's CEP. The Roadmap and the VCE/Community Energy analysis provided detailed results that we were able to analyze and compare to our Plan. The WIS:dom model of VCE and the Pathways model used by E3 in the Roadmap both strive to optimize results in the power sector in a somewhat analogous manner to our EnCompass tool. I show below in Figure JWI-D-2 a comparison of the Roadmap work and the VCE work to the preferred plan under our CEP.

Figure JWI-D-2: PSCo, VCE, and CEP Colorado Roadmap – Percent Change in Capacity (MW) from Baseline to 2030



Legend	Scenario or Portfolio
CEP	PSCo SCC7 Preferred Plan CEP
V1	VCE – CRS Gradual Coal Retirement
V2	VCE – CRS Coal Retired by 2025
V3	VCE – CEDS Retire Coal
V4	VCE – CEDS Deep Decarbonization
RM1	CEO/E3 2019 Action Plan
RM2	CEO/E3 HB1261 Scenario

Notes: Baseline years vary between cases. The VCE cases use a baseline year of 2018, while we compared 2020 to 2030 for the Roadmap cases. The PSCo CEP uses a 2020 baseline year. Dispatchable resources are labeled "Gas" for brevity in the figure above.

Q. CAN YOU PLEASE EXPLAIN FIGURE JWI-D-2?

A. Yes, some explanation is helpful in order to unpack this figure. We built the figure to create a comparison between the statewide Colorado Roadmap, statewide VCE analysis and our Public Service-specific ERP/CEP. To make these data comparable, we "normalized" the data by expressing the changes on a percentage basis. Then we took the baseline capacity of each effort (2018 for VCE, 2020 for

Public Service and Roadmap), and compared that to 2030 capacity by technology. The result is a comparison of major capacity changes by technology across the major technology types. As the resource planning process is primarily concerned with incremental capacity, capacity changes, and capacity retirements, Figure JWI-D-2 presents a way to compare these analyses across such changes over time.

The cases also merit some some explanation. I walk through these below, and these cases are also described in more detail in Attachment JWI-2:

- The "CEP" case is Public Service's CEP preferred plan, called SCC 7 in our presentation of portfolios, as in Company witness Mr. Hill's Direct Testimony.

- VCE analysis:
  - "V1" is a gradual coal retirement case where coal units retire by 2035 as chosen by the model.
  - "V2" is compared in a 2018 study to V1 and retires coal plants earlier, by 2025. V2 had higher electricity costs than V1 but also greater emissions reductions by 2030.
  - Note: There is a third case in this 2018 VCE study, that allowed coal plants to run to 2040. This case was so different from Public Service's CEP preferred plan that the comparison would have been less relevant, so we did not include that case here.
  - "V3" is from a 2019 VCE analysis that again focused on coal plants, retiring most by 2035.
  - "V4" is from the 2019 VCE analysis and features a high degree of electrification of vehicles and heating loads which spreads more energy sales over the capacity investments and claims lower electricity rates. This case also builds by far the most solar and storage of any case we looked at here.

- Roadmap analysis:
  - "RM1" 2019 Action Scenario focuses on reductions within the power sector and achieves 80 percent reduction.
  - "RM2" HB 19-1261 Target also achieves 80 percent reduction in the power sector, but assumes higher electrification of heating loads and vehicles, resulting in 21 percent more generation in

2030 in turn driving generally greater amounts of new capacity additions of wind, solar, and gas/dispatchable capacity.
- Note: the Roadmap included a reference case; however, the emissions reductions are considerably less than the CEP preferred plan, so we did not include that case here.

Q. WHAT DOES FIGURE JWI-D-2 TELL YOU?

A. At a high level, across all technologies and seven model scenarios shown above, our CEP preferred plan is within the range of the Roadmap and VCE scenarios. Across all technologies, and across these sets of analysis, I think it is notable that there is no case in which the CEP preferred plan is an outlier. For most technologies, there are at least two cases above and two cases below the CEP. Thus, I believe the Roadmap work, the VCE work and our own resource plan modeling are directionally consistent.

Across fossil generation, the CEP is on the lower end of new gas or "dispatchable" capacity added. The CEP is in the middle of the four VCE scenarios, and lower than either Roadmap scenario in terms of construction of new natural gas generation. For coal retirements, the results are clustered fairly closely together. The CEP retires somewhat less coal capacity than five of the other six runs, but this is also expressed on a pure capacity basis; the CEP, however, proposes to limit the Comanche 3 unit to a 33 percent capacity factor while maintaining the 500 MW of Company-owned Comanche 3.

For renewable additions, the CEP is again generally in the middle of the range of scenarios. It is notable that two of the scenarios here, the V4 VCE scenario and the RM2 HB 19-1261 Roadmap scenario, are focused on a high degree of economy-wide electrification. Those two runs build much higher levels of renewables, in conjunction with power sector decarbonization. The RM2 Roadmap scenario increases statewide wind capacity by over 200 percent to 12 GW overall, and the V4 VCE scenario builds nearly 15 GW of solar by 2030, an approximate 1000 percent increase. If Public Service had half that solar on its system, 7.5 GW, that would be approximately equal to our current peak demand. For storage, the results are a bit more varied, perhaps reflecting the relatively newer role storage is playing in the power system and the lower degree of certainty in its buildout. Here again, the CEP is in the middle of the capacity addition range.

Q. DO YOU THINK THESE STUDIES COULD HAVE CONSIDERED ALL THE DETAILS THAT THE COMPANY CONSIDERED IN DEVELOPING ITS 2021 ERP & CEP?

A. No. As but one example, the external studies generally consider a narrow set of options for coal plants: retire or run. By contrast, the Company presents in its case more variation in the potential outcomes in the two coal units that we focused our CEP cases across, Pawnee and Comanche 3. By considering the potential outcomes for these plants across retirement, fuel switching, limited operations, and "business as usual," we presented a wider set of results for the Commission to consider with these plants, and with the resulting clean energy portfolios. We also chose and presented an arguably more nuanced preferred plan, with a conversion to natural gas for Pawnee and a limited operations mode for Comanche 3. I am not clear that any of the external studies considered, or had the capability to consider, these types of outcomes. But we believe our preferred plan offers a balanced outcome, one that considers factors such as community and workforce transition along with cost, emissions, and the need for new dispatchable capacity.

Q. WHAT DO THE NATIONAL MODELS CONCLUDE?

A. The national models that look at economy-wide emission reductions all show significant energy system changes beginning in the 2020s with a significant increase in renewable electricity over that period. One recent study, "Accelerating Decarbonization in the U.S. Energy System," published in 2021 by the National Academy of Sciences, was performed as a consensus study of dozens of recent papers and reports. It concludes that most near-term emission reductions during a transition to net zero emissions would come from the electricity sector.[16]

Q. DOES THE NATIONAL ACADEMY OF SCIENCES STUDY DISCUSS COAL PLANT RETIREMENTS AND SYSTEM RELIABILITY?

A. Yes. The study includes a discussion of the use of some coal plants today for reliability service, and that it may not be possible to retire their capacity unless it is replaced with sufficient amounts of other resources capable of providing similar service (like today's new natural gas capacity). The authors acknowledge it may be difficult or impossible to get approval for those new fossil units. When considering the national energy generation mix, the report concludes that natural gas installed capacity may remain flat nationally but that natural gas plants play a

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[16] *See Accelerating Decarbonization in the United States Technology Policy and Societal Dimensions*, National Academies of Sciences, Engineering, and Medicine 2021, Washington, DC: The National Academies Press, available at https://www.nationalacademies.org/our-work/accelerating-decarbonization-in-the-united-states-technology-policy-and-societal-dimensions.

key role in firm capacity that is not weather dependent, or is less weather dependent. Further, the report concludes that some natural gas capacity may in fact be maintained through 2050. This may take place with less frequent operation and with hydrogen blending or replacement of natural gas to reduce carbon intensity. This is the scenario the Company modeled as a means to address its goals to achieve 100 percent clean energy by 2050 while continuing to get value from today's combustion technologies such as combustion turbine units.

Q. DOES THE NATIONAL ACADEMY OF SCIENCE REPORT DISCUSS THE ENERGY MIX IN THE FUTURE?

A. Yes, the study authors address the importance of technology options in achieving carbon reduction goals. Further, the authors share that modeling that limits technology options results in higher overall mitigation costs than solutions that are technology neutral. Beyond cost, the study shares that scenarios that remove viable options generally present a greater risk of failure as they depend heavily on the scale-up of favored technologies without impediment by any social, financial, regulatory, or other barriers.

Q. DOES THE NATIONAL ACADEMY OF SCIENCE REPORT DISCUSS ENERGY SYSTEM MODELING GENERALLY?

A. Yes, a conclusion of the report is that no model currently exists that is capable of modeling all elements of a net-zero system at a necessary level of detail, and that development and improvement of modeling capabilities will be important to selecting the best pathways toward carbon reduction achievement.

V. ELECTRIC RESOURCE PLANNING AND OTHER PLANNING PROCESSES

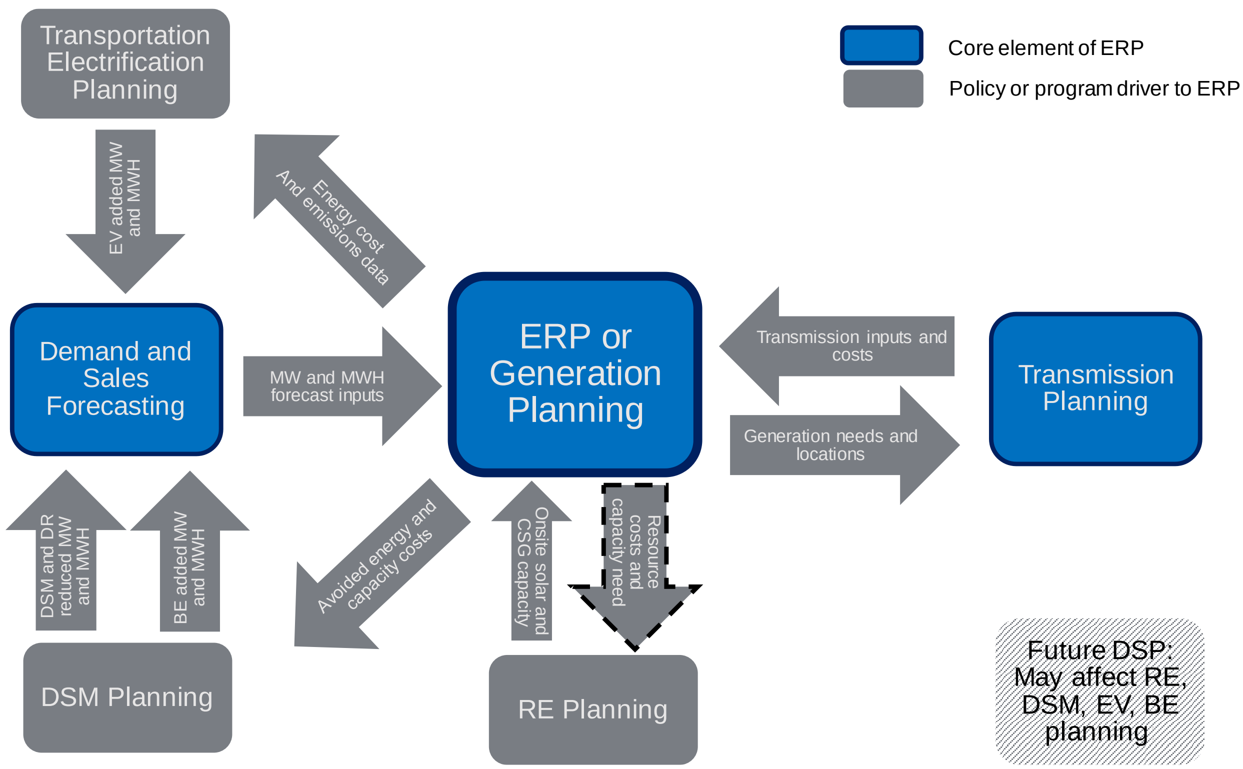
Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I discuss how the ERP process interacts with other planning processes, such as transmission planning, Renewable Energy Standard ("RES") planning, Demand-Side Management ("DSM") planning, and Transportation Electrification Planning ("TEP"). I further discuss which Commission decisions are associated with other processes, and which are generally in the domain of ERP proceedings.

Q. DOES THE ERP PROCESS INTERACT WITH OTHER PLANNING PROCESSES?

A. Yes. In various ways, the ERP interacts with several other utility planning processes. While the ERP is a significant planning endeavor, and in many ways sets the direction for our electric utility system, the ERP also interacts with transmission planning, gas utility planning, RES planning, TEP, DSM planning including beneficial electrification, and distribution planning. I provide Figure JWI-D-3 below as an illustration of some of the planning process interactions, which I will describe further below.

Figure JWI-D-3: The Interaction of the ERP and Other Planning Processes



Q. WHAT DOES FIGURE JWI-D-3 ILLUSTRATE ABOUT PLANNING?

A. Figure JWI-D-3 shows several planning processes and the relationships between them. The boxes represent the planning processes, and the arrows represent the major flows of information between those planning processes. I believe Figure JWI-D-3 illustrates several things. First, the ERP generation planning process is a crucial process at the core of utility planning that affects and is affected by several others. Figure JWI-D-3 also shows that demand and sales forecasting is foundational to resource planning, and that generation planning and transmission planning are inextricably linked. Beyond these core elements, several program or policy elements also influence resource planning. Quite often, as is the case for

DSM programs, beneficial electrification programs, electrification programs, and onsite renewable energy programs, these program and policy elements affect the ERP through the core element of demand and sales forecasting.

Q. WHAT DECISIONS IS THE COMMISSION MAKING IN THE GENERATION RESOURCE PLAN OR ERP PROCESS?

A. At a high level, the ERP process centers on decisions on new larger-scale generation resources. In Colorado, the Phase I ERP decisions focus on developing assumptions and setting the stage for the competitive acquisition process, which occurs in Phase II. The Phase II decisions focus on approving actual portfolios assembled from bids provided into the competitive acquisition process. The ERP can also focus in Phase I on decisions concerning retirements of older units, as is the case with this 2021 ERP & CEP as well as the Company's last ERP. Our 2021 ERP & CEP seeks several other Commission decisions, several of which are required by SB 19-236 and described at the end of my Direct Testimony and in more detail throughout the Company's direct case. Figure JWI-D-3 above illustrates that several other non-ERP planning processes, which have their own Commission proceedings, are the appropriate venues for decisions on DSM, electric vehicle programs, onsite solar and community solar programs, and beneficial electrification. Those processes and decisions do affect resource planning, but are considered in the appropriate proceedings. For example, the Company expects to propose a new RE Plan during 2021, and will also file a DSM Strategic Issues proceeding in the spring of 2022.

Q. HOW CAN THESE VARIOUS PROCESSES HELP THE COMMISSION MAKE THE BEST DECISIONS AFFECTING LONGER TERM RESULTS?

A. While SB 19-236 requires that decisions creating a CEP through 2030 be made in this ERP, I believe it is possible to make well-informed decisions in this case with the information at hand now. First, the ERP process is information-rich, with significant but different information presented in Phases I and II, as described throughout our direct case. Second, not all decisions affecting 2030 are made in this ERP. For instance, there will be at least one more ERP cycle, in approximately 2025, that will occur during this RAP. Also, there will likely be two to three each of RE Plans, DSM Strategic Issues filings, and TEPs before 2030. New planning processes that may also come into play include distribution system planning and separate beneficial electrification planning. In short, there are manifold opportunities beyond this ERP cycle for the Commission to continue to influence the energy supply, demand, customer choice, and emissions outcomes to 2030 and beyond.

Q. DOES THE COMPANY'S PHASE I FILING ADDRESS THE DIRECTION OF THE DECEMBER 20, 2019 JOINT SUPPLEMENTAL COMMENTS LED BY THE COLORADO ENERGY OFFICE PERTAINING TO COMMISSION RULE 3606(b)?

A. Yes. The Company participated in that consensus discussion and supported the proposal. While the joint proposed Rule 3606(b) was ultimately not incorporated into Commission Rules, given the consensus around this proposal we have nonetheless developed a range of demand forecasts with base, high (or

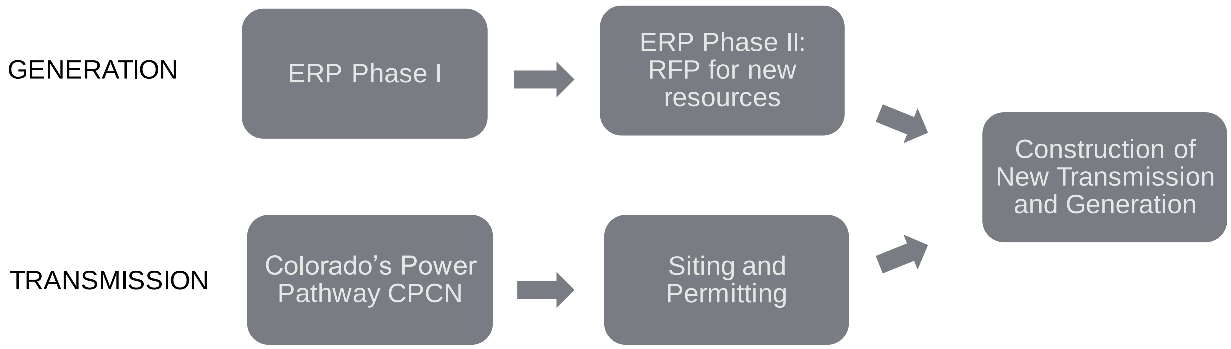
Roadmap), and low demand and sales, as described by Company witness Mr. Goodenough. The base forecast reflects Commission-approved DSM Plan assumptions, Commission-approved RE Plan distributed energy resources ("DERs"), and a Commission-approved TEP, as joint proposed Rule 3606(b)(I) describes. The Company's high/Roadmap load sensitivity is based on the Colorado Greenhouse Gas Pollution Roadmap report and, in particular, its higher electrification outcomes for both vehicle and non-vehicle electrification. This is consistent with joint proposed Rule 3606(b)(II).

Q. DOES THE COMPANY COORDINATE GENERATION AND TRANSMISSION PLANNING?

A. Yes. As I discuss above, these processes have been strongly related to each other for decades as large-scale generation and transmission development are inherently intertwined. This coordination has become more critical as we have shifted the system toward renewable energy in renewable resources zones which are further from our load centers, and this in turn increases dependence on transmission development. Also, with lower capacity factors as compared to traditional baseload generation, we have had to interconnect more capacity to obtain similar or greater generation. Another factor creating a need for further coordination is the frequent expiration and reinstatement cycles of the federal production tax credit ("PTC") for wind and investment tax credit ("ITC") for solar. Due to the continual potential expiration of these credits, we are often pursuing value for our customers from these tax credits by seeking to get renewable generation online by a certain deadline date, which requires associated transmission development on a firm timeline as well. At the time of this writing, we find ourselves in that situation yet again as both the PTC and ITC are effectively expired or reduced in value after 2025.

Senate Bill 07-100 ("SB 07-100") sought to address the challenge of coordinating generation and transmission planning by creating processes to specifically identify renewable-rich resource zones and to plan for proactive transmission development to enable renewable generation in those zones. Our Colorado's Power Pathway 345 kV Transmission Project ("Pathway Project" or "Colorado's Power Pathway") proposal takes this concept further by proposing a significant new transmission backbone to support the renewables necessary to achieve the aggressive emissions goals Colorado has set for the power sector, while proceeding on a timeline to leverage the current availability windows of the PTC and ITC. The Pathway Project was borne out of planning processes conducted pursuant to Rule 3627 (which stemmed from SB 07-100) and through the Colorado Coordinated Planning Group. These planning efforts are described in much greater detail in the Pathway Project Certificate of Public Convenience and Necessity ("CPCN") application filing in Proceeding No. 21A-0096E. The Company has proposed the Pathway and this ERP in a way to allow parallel and complementary Commission processes, followed by, if approved, a sequenced transmission buildout that can meet aggressive but achievable generation build schedules. Please see Figure JWI-D-4 below.

Figure JWI-D-4: Coordinated Generation and Transmission Planning: Colorado's Power Pathway and the CEP



Q. HOW ARE WHOLESALE CUSTOMERS CONSIDERED IN THE GENERATION PLANNING PROCESS?

A. Public Service maintains long-term requirements wholesale contracts with four cooperative and one municipal utility to provide energy, capacity, and reliability support. Periodically, these contracts can be amended or terminated at the request of either Public Service or the customer. If one of these contracts is amended or terminated in a way that increases or decreases the Company's obligation to serve a wholesale customer's load, the Company's demand and energy sales forecasts are adjusted to reflect the change. Most recently this process played out with the decision by Intermountain Rural Electric Association ("IREA") to terminate their wholesale customer agreement with Public Service effective December 31, 2025.

The forecasting process with respect to wholesale customers is described in more detail in Section 2.2 of Volume 2 (Attachment AKJ-2). In addition, Company witness Ms. Quillian describes how the termination of the IREA contract affects our 2005 emission baseline and 2030 clean energy target. The answer, to cut to the chase, is that IREA was already excluded from the 2005 baseline based on the potential for them to file a CEP (they were thus excluded to avoid double-counting) and our emissions in 2030 will not reflect service to IREA. Accordingly, they have been backed out of both sides of the carbon analysis equation.

Q. HOW DOES THE ERP PROCESS INTERACT WITH THE RE PLAN PROCESS?

A. As Figure JWI-D-3 above shows, the forecasted installed capacity and generation from onsite solar and community solar gardens ("CSG") becomes an input to the ERP. The effect of the ERP on the RE Plan is less clear at this time. We see additional opportunities to further integrate distributed energy or RES planning with the ERP process; DERs could be more aligned with system resource needs, and DER costs and benefits could be considered alongside larger solar costs and benefits. I incorporated a dashed-border arrow onto JWI-D-3 above to reflect these opportunities. It is the Company's view that the costs of the onsite solar and CSGs should be compared to lower-cost renewable generation opportunities, especially solar generation that have been available through ERP bids in the last few years. This comparison can inform how to structure programs under the RE Plan. Moreover, Company witness Mr. Trowbridge provides an overview of the role of the RESA and its potential role in funding eligible components of the 2021 ERP & CEP.

Q. DOES THE COMPANY HAVE UPDATED SOLAR COSTS FOR COMPARISON OF DIFFERENT TYPES OF RESOURCES?

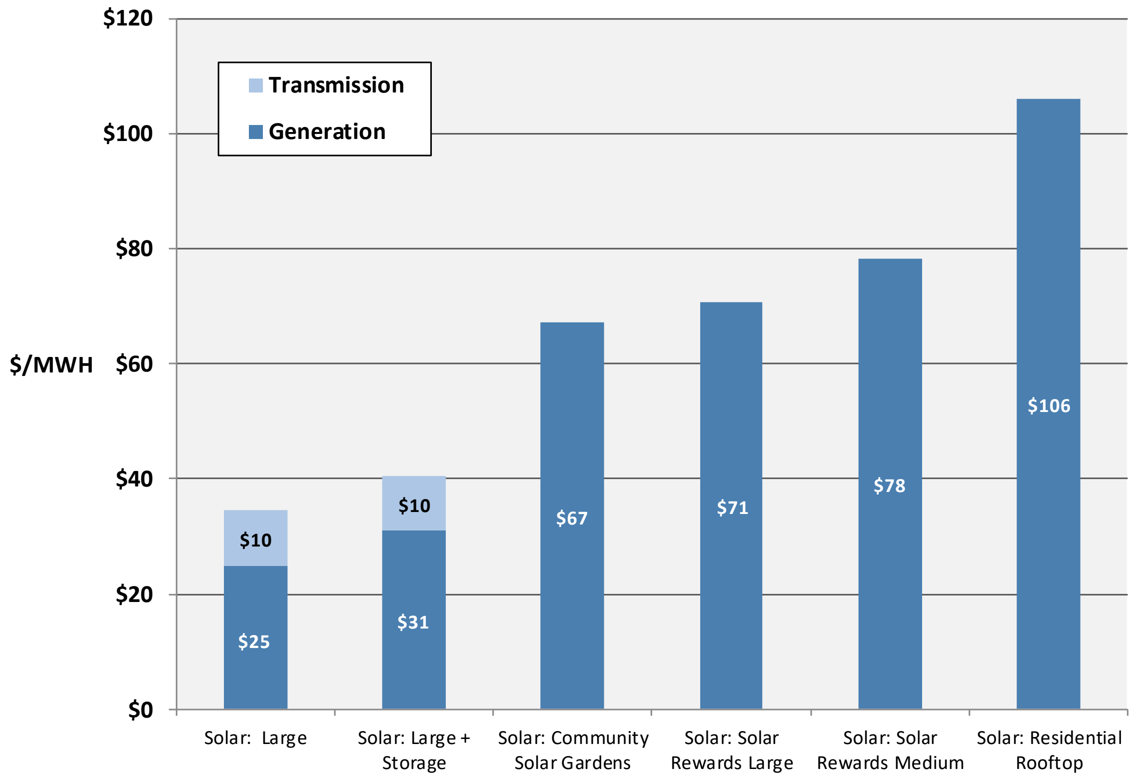
A. Yes. We presented a point-of-generation or "busbar" levelized cost of electricity comparison in Proceeding 19A-0369E, the 2020-2021 Renewable Energy

Compliance Plan ("2020-21 RE Plan"). Here, I seek to update that information and also provide relevant context about transmission and distribution costs. I find it useful to update this information for two reasons. First, some updated point-of-generation costs are available. These are the costs of generation at the generator before any transmission or distribution costs, if applicable, are applied, and are sometimes called "busbar costs." Here, I simply refer to them as generation costs. Second, the Company's Pathway Project transmission proposal in Proceeding No. 21A-0096E included cost information that is relevant in comparing large-scale solar that requires transmission with onsite solar that may not. It is less clear whether CSGs should have transmission costs assigned, because CSGs are generally connected at the distribution level. I note however that House Bill 19-1003 has enabled CSGs to be interconnected anywhere within the utility's service territory. Without the previous geographic restrictions that limited CSGs to serving customers in the same or adjacent counties, starting with the 2020 RFP cycle, CSG developers have the option to seek development located further from load centers and may rely more on transmission to deliver energy to their potentially disbursed distribution level customers. Nonetheless, we apply no incremental transmission costs to CSGs here, and leave that as a topic for future development.

Q. WHAT ARE THE COSTS THAT THE COMPANY FINDS FOR DIFFERENT TYPES OF SOLAR?

A. Figure JWI-D-5 below provides an estimate of costs for different types of solar. As this new cost estimate now incorporates transmission cost information, I discuss this as a delivered energy cost. I believe that this perspective provides a more accurate comparison than the generation-only data that I presented in the 2020-21 RE Plan.

Figure JWI-D-5: Estimated Delivered Cost of Additional Solar Electricity in Public Service Territory



Note: This estimate reflects what Public Service's electric customers are paying or will pay across these resource types for new capacity additions in the ERP and RE Plans. Large solar reflects levelized costs of electricity expressed via PPAs. Community solar gardens and onsite solar reflect payments made by the Company and its customers for this generation; REC values are applied to Solar*Rewards Medium and Solar*Rewards Large. No distribution costs are applied here for onsite and CSG, though distribution improvements may be required over time to support these resources.

Figure JWI-D-5 shows that larger solar is significantly less expensive than CSGs or any of the onsite solar program sources. This is true while accounting for a transmission cost adder for large solar that reflects a per-kilowatt-hour ("kWh") estimate built from cost assumptions for the Pathway Project.

Q. DOES THE HIGHER COST OF ONSITE AND CSG SOLAR AFFECT PRESENT VALUE RESULTS IN THE ERP?

A. Yes. Our base assumptions in this ERP considered about 1,158 MW of combined onsite solar and CSG coming online from 2021 through 2030. The Company also performed a sensitivity analysis (called "Low Load") that considered about 1,556 MW of onsite solar and CSG, or roughly one-third more of these resources. In both cases, onsite and CSG are each about half of the total amount of solar coming online through the RAP. The present value of revenue requirements results of the higher onsite/CSG case are $184 million higher than the preferred plan case. The emissions results are virtually the same, however, as the model significantly reduced the amount of large solar acquired (by about 550 MW) in the high onsite/CSG case. Accordingly, emissions reductions are similar between the two cases but the high onsite/CSG case is higher cost, resulting in higher overall costs to achieve the same emission reductions. Further discussion of sensitivity case results is available in Volume 2 and in Company witness Mr. Hill's testimony.

Q. WHAT DO YOU CONCLUDE FROM THESE RESULTS?

A. I believe that these results help to confirm that the Company's approach under the preferred plan and the Pathway Project is sound. That is, investing in the transmission system to source significant amounts of new large solar and wind capacity is a cost-effective step toward achievement of Colorado's emission reduction objectives. The Company's forecast of 1,158 MW of onsite and CSG solar represent our forecast of those technologies, and they too contribute to emission reductions, but they do so at a higher cost. There are potential benefits to onsite and CSG solar that I have not attempted to reflect here; these range from providing customer choice to potentially adding resiliency and the potential to avoid some distribution upgrades through non-wires alternatives. These are subjects for the RES planning process and future distribution system planning processes. I provide this delivered cost estimate here in the ERP to advance the conversation and provide some potentially useful feedback from the generation (ERP), transmission planning (Pathway Project proposal), and distribution planning processes into the upcoming RES planning process, which will commence later in 2021 with a Company RE Plan filing.

VI. DISPATCHABLE GENERATION AND GREENHOUSE GAS EMISSIONS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony I describe the issue of carbon dioxide emissions related to natural gas generation, with a focus on potential new gas generation that may be acquired through this 2021 ERP & CEP. I also describe the Company's efforts to minimize emissions and create a transition pathway to lead to 100 percent clean energy and a carbon-free future—the Company's long-term goal.

Q. DOES THE COMPANY RECOGNIZE THAT ANY NEW FOSSIL-FUEL POWER PLANT IT MAY PROPOSE TO ADD IN THIS 2021 ERP & CEP MUST BE COMPATIBLE WITH THE STATE'S AND OTHER GHG TARGETS?

A. Yes. The Company recognizes that carbon dioxide emissions from new fossil facilities (or potentially existing ones added as PPA extensions or plant lifetime extensions) raise questions about the compatibility of such facilities with GHG targets. For instance, as discussed above, HB 19-1261 creates an economywide target of 50 percent GHG reduction by 2030 and 90 percent by 2050, and SB 19-236 creates a carbon dioxide reduction requirement of 80 percent by 2030 and a goal of 100 percent clean energy by 2050. Further, and before either of these two statutes existed, Xcel Energy established its goal to deliver 100 percent carbon-free electricity to customers by 2050.

Q. WHY WOULD THE COMPANY CONSIDER ADDING ANY NEW FOSSIL GENERATION WITH SUCH FUTURE GHG REQUIREMENTS?

A. Simply put, we may have little choice. As established in the Direct Testimonies of Company witnesses Mr. Hill and Mr. Welch, there continues to be a need for firm, dispatchable generation resources that can be relied upon to provide energy for longer-duration periods of time, from many hours to days. Our modeling predicts that this need will also continue to exist in the future, as we move to very high levels of variable renewable energy in this RAP. Further, such resources will be needed to meet peak load, and also to balance the very high levels of renewable energy we are proposing.

Q. WILL THE COMPANY SPECIFICALLY SEEK NEW FOSSIL-FUELED GENERATION LIKE NATURAL GAS IN THE PHASE II PROCESS?

A. No. We will seek resources under an all-source solicitation that seeks the best of nearly all fuel types.[17] Next, we will build portfolios from the best combinations of generation and storage bids (or existing generation bids) that meet the needs of the system. We fully expect that we will need to add firm, dispatchable resources; indeed, based on generic modeling conducted as part of our Phase I filing we project that need at approximately 1,300 MW. But again, we do not seek these or any resources specifically by fuel type. All that said, based on our understanding of the costs and capabilities of various generation and storage options, some degree of additional natural gas generation may prove to be the most cost-effective

[17] Public Service will not accept bids for coal-fired generation in this 2021 ERP & CEP.

and viable option to maintain the system reliability we need as we go to increasingly higher levels of variable renewable generation.

Q. IS ADDING ANY NEW FOSSIL OR GAS-FIRED POWER PLANT CONSISTENT WITH THE TARGETS YOU MUST ACHIEVE?

A. Yes, it can be. As shown in Mr. Hill's Direct Testimony, adding approximately 1,300 MW of firm dispatchable generation from natural gas is not only consistent with the 80 percent by 2030 clean energy target under SB 19-236—it can also can support a portfolio that beats the target. To that point, our preferred portfolio is estimated to achieve an emission reduction of approximately 85 percent from 2005 levels by 2030. Our long-term model-based forecasting identifies a pathway (in fact several) under which adding new gas-fired resources in the RAP is consistent with meeting or outperforming the 2030 carbon dioxide targets.

Q. IF THE COMPANY FINDS THAT IT NEEDS TO ADD NATURAL-GAS FIRED GENERATION, HOW IS THAT COMPATIBLE WITH LONGER-TERM TARGETS SUCH AS THE COMPANY'S OWN 100 PERCENT CLEAN ENERGY BY 2050 GOAL?

A. The need for a zero-carbon firm dispatchable resource is a primary technology development objective of the Company and the industry, as we and most other utilities increase our use of renewable energy and reduce our emissions. Nevertheless, we have identified one pathway under which acquisition of new gas-fired generating technology may be fully compatible with zero-carbon long-term targets. As Company witness Mr. Landrum explains in his Direct Testimony, the Company modeled the long-term part of its resource plan modeling, specifically

2040-2050, with an assumption that the combustion turbine-based generation resources in its system would begin to incorporate increasing amounts of hydrogen, eventually reaching full hydrogen by 2050. We do not have perfect foresight on whether this will happen, or whether other technologies will instead fill this need, but we do feel that this outcome is plausible and helps to answer the question of the longer-term usefulness of gas resources. Also, please see the penultimate section of my testimony, which discusses technology advancement toward post-2030 targets.

Q. WHAT STEPS IS THE COMPANY TAKING TO REDUCE EMISSIONS, ADDRESS POTENTIAL FUTURE STRANDED COST CONCERNS, AND BUILD A TECHNOLOGY PATHWAY TO A ZERO-CARBON FUTURE?

A. First, we are proposing to add significant new large-scale renewable energy resources, about 3,900 MW of wind and solar, in this RAP. This follows the Commission-approved Colorado Energy Plan, under which we have been adding approximately 1,100 MW of wind and 800 MW of solar from 2020 to 2022. Harnessing renewable energy to this extent has two effects in terms of gas resources: first, adding renewables, all else equal, tends to reduce fossil generation on the system. Second, as renewables are generally considered to be "energy" resources more than "capacity" resources, adding more renewables tends to decrease the economic competitiveness of natural gas combined-cycle generation, which is also more of an "energy" resource. This effect shows up in our current modeled portfolio results, which anticipate that we will not likely be adding any combined-cycle generating capacity. I believe this is a significant finding, as natural gas combined-cycle resources tend to run much more, and therefore emit much more carbon dioxide, than simple-cycle gas turbine power plants or gas internal combustion plants, which tend to have low capacity factors and relatively low emissions. I discuss the relative emissions of these types of units in our 2030 forecasting further below.

Q. WILL THE COMPANY CONSIDER OPPORTUNITIES TO EXTEND THE USE OF EXISTING NATURAL GAS FACILITIES?

A. Yes. First, the Company will consider bids from existing gas-fired resources. Though we anticipate the need for 1,300 MW of new firm, dispatchable resource need, we believe there are several hundred MW of existing resources in Colorado that could be bid into the Phase II RFP that may fill some of this need. The "re-use" of some existing gas capacity can be beneficial because existing resources may not have to recover their remaining investment costs over the length of time that new resources would, and thus can be bid with shorter contract terms or lower prices. Shorter terms and lower prices reduce stranded cost concerns. We saw this effect in the Colorado Energy Plan with the addition of the existing Manchief Facility at a purchase bid cost of approximately $150 per kilowatt ("kW"), roughly four-fifths lower than the generic natural gas combustion turbine capital cost of $788 per kW for a new combustion turbine facility assumed in our modeling, as detailed in Volume 2 of the 2021 ERP & CEP.

Q. DOES THE COMPANY'S RETENTION OF PAWNEE AND COMANCHE 3 AVOID THE NEED FOR SOME ADDITIONS OF NATURAL GAS RESORUCES?

A. Yes. Under our preferred plan, our proposed retention of the existing 505 MW Pawnee plant with a fuel switch to gas, and the retention of the existing 750 MW Comanche 3 under a proposed reduced operations mode, will both likely avoid additions of new natural gas-fired capacity. As Mr. Hill's Direct Testimony shows, under the modeled SCC 2 portfolio, which retires Pawnee in 2028 and Comanche 3 in 2029, we anticipate a need for 2,352 MW of firm dispatchable resources. By contrast, our preferred plan (or SCC 7), which retains Pawnee on natural gas and retains Comanche 3 on limited operations, only sees a need for an additional 1,276 MW of firm dispatchable resources. Clearly, retaining the Pawnee and Comanche 3 units reduces the need for additions of firm dispatchable resources, which can avoid investments in new combustion turbines.

Q. WILL THE COMPANY SEEK TO DRIVE NEW TECHNOLOGY TO REDUCE THE CARBON DIOXIDE EMISSIONS FROM COMBUSTION TURBINES?

A. Possibly. We understand that equipment manufacturers are developing the capability to combust hydrogen in combustion turbines and also in reciprocating internal combustion engine ("ICE") generation equipment. We are interested in taking a step toward this capability in our generating fleet, and it could be possible to seek bids with the capability to combust at least 30 percent hydrogen by volume with technology now or nearly available.[18] Thus in this Phase I filing, and in the subsequent Phase II competitive acquisition process, we are seeking more information. We seek input in Phase I from parties to this 2021 ERP & CEP proceeding as to whether acquiring this hydrogen capability would be supported, and at what cost and performance capabilities it could be delivered. We are interested in the Commission's perspective on this approach as well. Further, in Phase II, we plan to seek bids for combustion turbine and ICE generators with hydrogen combustion capability at 30 percent by volume or more. We would encourage such bids to provide cost information on this capability by providing bids with and without the capability, including the price of each, and we would allow such bids under one bid fee. We seek input from parties to this case and also from the Commission on this overall approach to drive a lower-emissions technology option associated with a firm dispatchable resource.

Q. WILL THE COMPANY SEEK TO MINIMIZE "UPSTREAM" OR SUPPLY-CHAIN METHANE EMISSIONS ASSOCIATED WITH ANY NEW GAS-FIRED GENERATION IT ADDS IN THIS RESOURCE PLAN?

A. Yes. Another step we are considering is to obtain natural gas associated with gas additions to our generating fleet from "certified" or "responsibly-sourced" natural gas ("RSG") sources. This purchasing commitment would use third-party measurement and certification to ensure our natural gas would come from

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[18] Hydrogen gas contains approximately one-third the energy content of the same volume of natural gas. Therefore, burning 30 percent by volume hydrogen blended into natural gas would reduce CO_2 emissions by approximately 10 percent. As the percentage of hydrogen increases, the percentage of the CO_2 reduction would also increase, with 100 percent hydrogen achieving 100 percent CO_2 reduction.

producers that are responsibly controlling upstream methane emissions. We are considering whether to obtain, on a calendar-year basis, the volumetric equivalent of the gas consumed by any new gas-fired generation resources from RSG.[19] Based on our research, we believe that this higher-standard type of natural gas sourcing can be obtained for a relatively small cost increase of between $0.10 per mmBtu and $0.20 per mmBtu. Beyond the benefit of reducing upstream methane emissions, our certified natural gas proposal carries the benefit of allowing the Company and the Commission to signal to other sectors, specifically the upstream natural gas production sector, that emissions reduction is an important priority. Also, as RSG is a newer concept, we believe that the Company's pursuit of this concept can help the certification organizations to develop their programs, and also help the upstream gas producers to drive reductions in their operations.

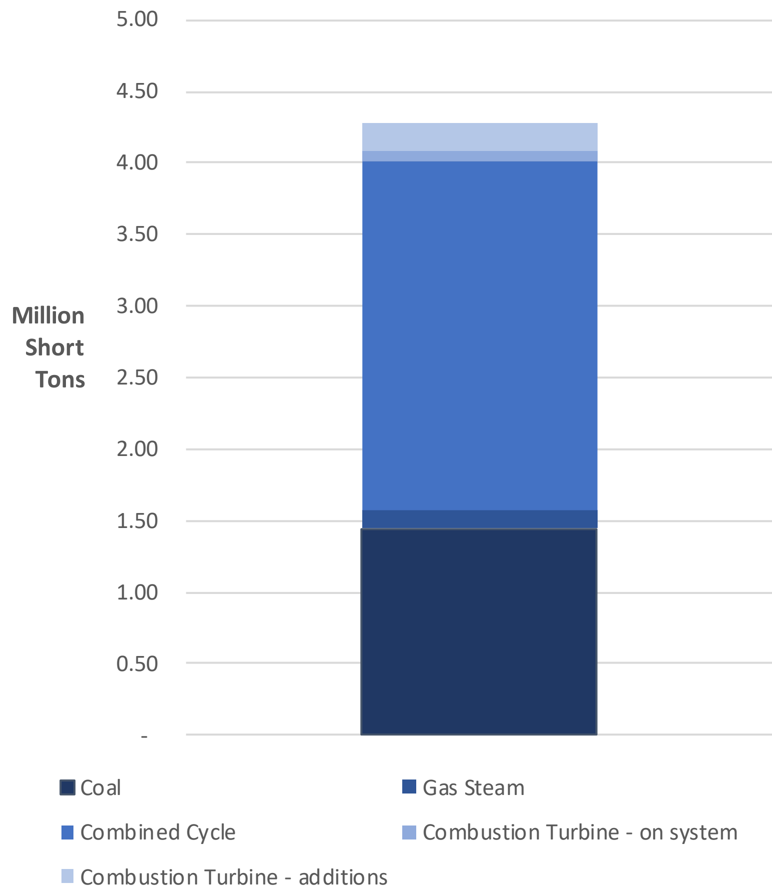
The Company is interested in exploring this conceptually within the ERP, with possible implementation in a future appropriate filing. We seek party input and Commission perspectives on the costs and benefits of pursuing this RSG step.

[19] Further development on implementation of this concept is likely needed, and the Company expects it would need some flexibility as to the time period after any calendar year to obtain the certified natural gas at the best possible price. This may require some time flexibility beyond the calendar year of consumption for the sourcing of the certified natural gas. Further, this concept may require some pricing parameters to ensure that the Company is not overcommitted to this requirement if sufficient certified natural gas is not available, or available at a relatively low price increase level.

Q. OVERALL, DO YOU EXPECT NEW GAS-FIRED GENERATION TO BE A LARGE PORTION OF PUBLIC SERVICE'S CARBON DIOXIDE EMISSIONS IN 2030?

A. I do not. First, our preferred plan will reduce emissions about 85 percent from 2005 levels, even with any natural gas fueled combustion turbine or ICE additions. Of that total, I show below in Figure JWI-D-6 the expected contributions to our overall 2030 emissions from coal, combined cycle gas plants, existing combustion turbine and reciprocating gas plants, and new gas additions. Figure JWI-D-6 shows that new gas additions would represent a relatively small portion of these emissions, i.e., only 4 percent of the total, or about 200,000 tons. We forecast that these new gas-fired resources, while critically needed at some times to ensure reliability, meet peaking requirements, and integrate renewable energy, will only operate a small fraction of the time; our modeling of the preferred plan suggests that these units will have a 3 percent capacity factor in 2030. While some parties in this case are likely to have concerns about any new additions of gas-fired resources, and the associated carbon dioxide emissions, it is plain to see that when viewed with appropriate context, this is a relatively small issue. I also point out that the overall 2030 emissions we expect will be lower than today's levels, and more than 80 percent lower than in 2005. In summary, emissions from any new gas additions under the preferred plan are likely to be a small portion of a much-reduced emissions total.

Figure JWI-D-6: Preferred Plan Carbon Dioxide Emissions by Source Type in 2030[20]



Q. CAN YOU PLEASE SUMMARIZE THE BENEFITS OF ALL OF THESE EFFORTS TO MINIMIZE OR ADDRESS EMISSIONS FROM NEW NATURAL GAS GENERATION?

A. Yes. I think that our efforts to avoid combined cycle plants, maximize the use of existing gas-fired resources, implement renewable energy to avoid the dispatch of

[20] Total emissions from these sources differ slightly from overall EnCompass total emissions outputs shown elsewhere in this direct filing, as this figure does not consider market purchases and sales.

gas-fired generation, seek a broad set of technologies in bids, explore hydrogen capability in any new gas-fired generation, and consider supplying any gas-fired generation additions through certified lower-methane-emitting sources can:

- Minimize future potential stranded cost issues in the context of adding potential new gas-fired resources while also complying with future zero-carbon policy objectives;
- Support resource portfolios that exceed the statutory 2030 emissions requirement, and add minimal incremental emissions on a unit basis;
- Provide a signal to manufacturers and bidders that we need a technology pathway to a zero-carbon flexible, dispatchable, and long-duration generation or storage resource; and
- Create a best-practices resource acquisition model for other states and utilities that require flexible, dispatchable resources in their resource planning efforts.

VII. MISCELLANEOUS ISSUES

A. Resiliency and the CEP

Q. HOW HAS THE COMPANY ADDRESSED THE QUESTION OF RESILIENCY IN THIS FILING?

A. While we don't have a specific testimony on resiliency, we address this issue in many ways in our filing. In fact, it could be argued that reliability and resiliency is the core operating objective of resource planning. Planning new resources to meet expected loads is at the core of the resource planning process, as Figure JWI-D-3 above showed.

More specifically in this case, we address reliability and resiliency in the following ways. First, we develop a planning reserve margin, which is a long-standing practice that builds a certain amount of redundancy into the generation fleet. Company witness Mr. Carden of Astrapé Consulting testifies to the updated and increased planning reserve margin we are utilizing for this 2021 ERP & CEP proceeding. His analysis reflects an updated view of our system, including the increasing amounts of renewable energy we are anticipating as part of our efforts. Second, Company witness Mr. Scholl also sponsors studies we conducted internally, including a flex reserves study that analyzes the ability of our dispatchable fleet to integrate increasing renewable energy and an Electric Load Carrying Capability study which assigns the right capacity value to intermittent and time-limited resources. Third, as Company witness Mr. Welch discusses in his Direct Testimony, we explain how we are beginning to put more emphasis on planning for winter reliability conditions, especially with respect to the performance of wind and solar resources at those times of the year.

Fourth, Mr. Welch also explains several requirements we are creating for resource additions in the Phase II competitive solicitation. Specifically, we are calling for all added dispatchable resources to supply us with bids that include on-site fuel costs, so we can compare those to firmed natural gas supply. We are also requiring that dispatchable resource bids include cold-weather operations plans and have certain start capabilities to better meet the needs of increasing system variability. In addition, we are requiring wind generators to have specific cold-weather capability. We are also investigating the potential future need to expand the capabilities of natural gas storage fields to withdraw and inject more gas at certain times as gas ramping events become more frequent and more pronounced to balance a system with higher wind and solar capacity.

Fifth, the Company also provided a broad range of portfolio and sensitivity analyses with this 2021 ERP & CEP, and the Commission may benefit from considering those from a resiliency angle. Our portfolios consider various outcomes for the Pawnee and Comanche 3 units, and accordingly show differing new resource additions. We also included a "No New Gas Resources" sensitivity, which observes what happens if the model cannot choose new dispatchable capacity in the form of combustion turbines or combined cycles. In that sensitivity, the model selects several times more storage and somewhat more renewable energy to meet system needs, and finds several billion dollars in additional system costs as compared to the preferred plan. From these portfolios and sensitivities, the Commission can see results from cases that "solve" the demand and supply equation with equivalent reliability but with different sets of technologies.

Sixth, the transmission initiative we suggest in our associated Colorado's Power Pathway proposal (Proceeding No. 21A-0096E) would, if approved, bring a transmission backbone that accesses more renewables across a wider geographic scope, including potential southeastern Colorado wind. The Pathway Project is proposed as a networked solution, which allows for better recovery from loss of any single transmission component as compared to a radial transmission line.

Finally, our preferred plan would result in significant fuel diversity in terms of capacity on the system in 2030. The system would have significant and diverse capacity from wind, solar, natural gas (with some degree of onsite fuel backup), coal, batteries, and pumped hydro capacity. This ERP also tees up the potential for additional pumped hydro on the system in the future as well as an advanced longer-duration energy storage technology, molten salt, which could further diversity our capacity. Over the longer-term, we are also nudging bidders toward providing hydrogen capability information in their dispatchable resource bids, opening up another potential fuel type for future capacity on the electric system.

B. <u>Boulder Franchise Agreement Greehhouse Gas Benchmarks</u>

Q. PLEASE DISCUSS THE GHG BENCHMARKS THAT ARE IN THE BOULDER FRANCHISE AGREEMENT WHICH IS BEFORE THE COMMISSION FOR APPROVAL.

A. Certainly. The Boulder Franchise Agreement, approved by the electorate of the City of Boulder and the City Council after a decade long municipalization exploration, contains several emissions “benchmarks” and calendar years by which the Company believes achievement of those benchmarks will be obtained. The benchmarks and years are as below in Table JWI-D-3:

Table JWI-D-3: Greenhouse Gas Benchmarks in Boulder Franchise Agreement[21]

Calendar Year	Benchmark Emissions (million short tons, CO2e)
2022	16.6
2024	13.6
2027	11.5
2030	6.9

The Franchise Agreement specifies an opt-out provision that discusses terms under which, if the Company fails to meet these GHG progress commitments and emissions benchmarks, the City of Boulder may leave the Franchise Agreement. Importantly, however, the Commission is not bound by the benchmarks Public Service believes it will achieve in the Franchise Agreement with regard to any resource planning or other decision. The Franchise Agreement is between the Company and Boulder, and the opt-out provision structured into the Franchise Agreement merely creates an *option* for Boulder to exit from the Franchise Agreement should the Company not achieve a benchmark. The Company and Boulder both understand that the emissions outcomes are

[21] The Franchise Agreement defines the benchmarks as “greenhouse gas emissions directly associated with the generation of electricity sold to the Company's Colorado electricity customers in each of the following calendar years, as reported to The Climate Registry through its Electric Power Sector Protocol, consistent with Environmental Protection Agency Greenhouse Gas Mandatory Reporting Rule in 40 CFR Part 98…”

dependent on future Commission decisions in future proceedings, among other uncertainties.

Q. HOW DID THE COMPANY DERIVE THE SPECIFIC BENCHMARK LEVELS IT COMMITTED TO IN THIS AGREEMENT?

A. The Company agreed to these benchmarks in collaboration with Boulder during negotiations on this Franchise Agreement, noting here the aggressive clean energy and emissions targets that the State of Colorado, Public Service, and Boulder have all embraced. The Company considered several data points in agreeing to the benchmarks, which in effect describe one trajectory for emissions reductions between now and 2030. First, the Company considered its current emissions in 2019 that were associated with the generation of electricity. Next, the Company considered its likely emissions trajectory for the next few years as it implements the Colorado Energy Plan as approved in the 2018 Phase II Decision (Decision No. C18-0761) in Proceeding 16A-0396E. Notably, the Colorado Energy Plan implementation will include approximately 1,100 MW of wind and over 700 MW of solar coming online in the calendar years 2020 to 2022. It will also include the retirement of two coal units, Comanche Unit 1 in 2022 and Comanche Unit 2 in 2025. Further, the Company considered its plans to file this CEP under SB 19-236, which sets an 80 percent emission reduction target by 2030. We note that some of the elements which are needed to reach the 2027 benchmark have not been approved at this time, but we do anticipate that this 2021 ERP & CEP proceeding will likely result in clean energy additions in the 2025-2026 timeframe that we feel will allow achievement of that benchmark. In fact, we proposed the

Pathway Project and this CEP with an objective to pursue such additions in order to capture PTC and ITC value by end-of-year 2025, as discussed earlier in my Direct Testimony.

Q. DO THESE COMMITMENTS LIMIT THE COMMISSION'S DECISION-MAKING AUTHORITY ON RESOURCE PLANNING OR IN OTHER WAYS?

A. I do not believe so. First, the benchmarks are strongly influenced by what was already approved by the Commission in the Colorado Energy Plan, and by the 2030 emissions reduction requirement legislated in SB 19-236. Second, as explained in the previous question, the Company believes the benchmarks are consistent with, and representative of, what we hope will be the eventual outcome in this 2021 ERP & CEP filing, which are strongly directed by SB 19-236. I note that our preferred plan achieves carbon dioxide emissions of 4.3 million short tons by 2030, more than one-third below the 2030 benchmark of 6.9 million short tons in the Franchise Agreement. In fact, several of our proposed portfolios outperform the 2030 benchmark emissions target. From the Company's perspective, this commitment is somewhat similar to the December 2018 Xcel Energy-wide emissions commitments; Xcel Energy believed it could reach those targets and that it was appropriate to state them as our intention, but we did not and do not have approvals from our eight public utilities commissions to guarantee the achievement of the targets. Nonetheless we have committed to our customers, communities, regulators, and investors to strive to reach those targets.

VIII. PLANNING FOR THE FUTURE

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I discuss Xcel Energy's overall strategy and the Company's specific efforts within this 2021 ERP & CEP to advance technologies needed to achieve carbon dioxide emissions reduction targets beyond 2030 and ultimately 100 percent clean energy by 2050. In particular, I discuss Xcel Energy's contribution to launching the Carbon-Free Technology Initiative ("CFTI"). I also discuss Public Service's efforts to advance, develop, and commercialize technologies in this 2021 ERP & CEP by exploring advanced technology projects at Hayden, early development steps for "long lead time" resources such as pumped hydro storage, hydrogen-capable dispatchable resources, and use of RSG for any new natural gas-fired dispatchable capacity in this 2021 ERP & CEP.

Q. WHAT IS THE CFTI?

A. The CFTI is focused on implementation of federal policies that can help ensure the commercial availability of affordable, carbon-free, 24/7 power technology options by the early 2030s to help the electric power industry meet net-zero carbon reduction commitments. Participants in the CFTI include the Edison Electric Institute ("EEI") and its member companies (Clean Air Task Force, Bipartisan Policy Center, Center for Climate and Energy Solutions, ClearPath, Great Plains Institute, Information Technology & Innovation Foundation, Nuclear Energy Institute, and Third Way).

The CFTI focuses on policy recommendations to advance key technology areas:

- Advanced wind and solar energy systems;
- Long-duration storage and advanced demand efficiency;
- Advanced, dispatchable, and renewable super hot rock deep geothermal;
- Zero-carbon fuels, such as hydrogen;
- Advanced nuclear energy (both fission and fusion); and
- Carbon capture, utilization, and storage.

Ben Fowke, Xcel Energy's Chairman and CEO, who serves as current Chair of EEI, contributed leadership to EEI's development of the CFTI.[22]

Q. WHY DID XCEL ENERGY JOIN EEI AND OTHER GROUPS IN LAUNCHING THE CFTI?

A. In 2018, when Xcel Energy proposed to reduce carbon dioxide emissions 80 percent by 2030, and to achieve 100 percent clean energy by 2050, we recognized that we had a technology gap. We knew that implementation of existing technologies could achieve the 80 percent by 2030 target. In fact, our 2021 ERP & CEP proposed here demonstrates that fact. But we also stated at the time that the 2050 target would require further development of technologies that are not available today. The CFTI seeks to directly address this technology gap by implementing federal policies that can help ensure availability of affordable, carbon-free, 24/7 power technology options that we believe are needed to get to 100 percent clean energy by 2050.

[22] Further information on the CFTI is available at: www.carbonfreetech.org.

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL FOR THE HAYDEN GENERATION STATION, AND HOW IT LEADS TO ADVANCED TECHNOLOGY DEVELOPMENT.

A. As part of the preferred plan, as discussed by Company witness Ms. Jackson, the Company has proposed retiring both units at the Hayden facility by 2030 as part of its coal transition plan. Unit 1 will retire in 2028 and Unit 2 will retire in 2027. While there are clear carbon benefits to retiring these units as part of the Company's clean energy transition, they are also important economic drivers of the local community. As discussed further in the Direct Testimony of Company witness Ms. Velasquez Horvath, the annual tax revenues from these two units account for significant portions of the local county's educational funding as well as other tax and economic impacts. To help the community of Hayden to recover some of the lost tax revenue when Hayden 1 and 2 retire, provide job opportunities in the area, and advance technologies, the Company proposes a technology reinvestment program in and around the Hayden community. In my view, our approach is already putting the principles underlying the CFTI into action in an area that will be directly affected by the transition contemplated in our coal transition plan.

Q. PLEASE DESCRIBE THE COMPANY'S REINVESTMENT PLAN AT HAYDEN.

A. In short, the anchor for the Company's proposed community assistance plan for Hayden is reinvestment. Public Service has developed a shortlist of four projects it believes are promising opportunities to support the local community. These projects include a biomass syngas (hydrogen and carbon monoxide) project, a solar to hydrogen project, a molten salt energy storage project, and a partnership with the Colorado Parks and Wildlife department to develop a fish hatchery. The projects are innovative and have the potential to provide numerous benefits to the Hayden community and the wider state economy, all while furthering the State's emission reduction and just transition policy objectives. Accordingly, we believe the Commission should support the Company in continuing the development of these concepts and is bringing them forward for Commission approval—understanding that replacement generation included as part of this plan will need to be bid into the Phase II competitive solicitation and ultimately approved by the Commission as part of an approved resource plan. In her Direct Testimony, Ms. Velasquez Horvath provides further details on the projects and the benefits they provide.

Q. WHAT IS THE COMPANY PROPOSING IN TERMS OF LONG-LEAD TIME RESOURCES?

A. As Company witness Ms. Trammell explains this proposal in more detail in her Direct Testimony, we are seeking policy support and direction from the Commission to investigate the technological and economic feasibility of generation resources that possess characteristics required to achieve remaining or post-2030 carbon emission reduction goals. This is very similar to the objective of the CFTI. The Company believes that resources capable of providing longer-duration storage, such as pumped storage hydropower or other long-duration energy storage technologies, are required to achieve the emission reductions required beyond 80 percent. However, pumped hydro storage can take many years—as many as ten to twelve years—to develop. Here, the Company seeks to establish a clear policy position that it is reasonable for Public Service to investigate the initial suitability and feasibility of a future resource like pumped storage hydro in Colorado, and seeks to establish certain treatment of the costs incurred as a part of this investigation.

Q. IS THE COMPANY SEEKING TO ADVANCE LOWER-GHG GENERATING TECHNOLOGY IN RESOURCES ADDED IN PHASE II OF THIS ERP?

A. Yes. As I described earlier in Section VI of this testimony, we are encouraging bids for combustion turbine and ICE generators with hydrogen combustion capability. This sends a signal to IPPs and equipment manufacturers that reducing carbon in dispatchable options is important to us and to our customers and communities. We are also investigating whether to obtain the volumetric equivalent of the natural gas consumed by any new natural gas-fired generation resources added in this ERP from RSG sources. This sends a signal to upstream suppliers of natural gas that reduction of methane emissions is important, as the State's Roadmap identified when it showed upstream production emissions as the second largest potential source of GHG emissions reduction, behind the power sector.

Q. ARE THERE EXISTING STATUTORY MECHANISMS THAT CAN PROMOTE THE INTRODUCTION AND CONSIDERATION OF CLEAN ENERGY TECHNOLOGIES WITHIN PHASE II OF THIS ERP?

A. Yes. It would be helpful for the General Assembly to establish enhanced pathways for the acquisition of these types of projects. Nevertheless, under the existing

Public Utilities Law, § 40-2-123, C.R.S. ("Section 123") provides the Commission with the opportunity to consider new clean energy technologies as part of a utility's generation acquisitions in the ERP process. It identifies four specific benefits that may be considered:

- Energy security;
- Economic prosperity;
- Insulation from fuel price increases; and
- Environmental protection, including risk mitigation in areas of high wildfire risk.

Taking our Hayden reinvestment-based community assistance plan as an example, I believe three of the four identified concepts—molten salt storage, solar electrolysis, and biomass—achieve all of these benefits. I note also that the statute allows some discretion as to how these four benefits may be applied in specific cases.

Q. HOW DO THE IDENTIFIED REINVESTMENT CONCEPTS AT HAYDEN ACHIEVE THE ENERGY SECURITY BENEFIT?

A. Molten salt, solar electrolysis, and biomass could all provide energy security benefits through diversification because they are not reliant on the typical fossil fuel sources. Molten salt storage facilities can be charged when energy costs are low or the risk of renewable energy curtailment is high; solar electrolysis incurs no fuel costs; and the biomass generation concept could diversify the fuel mix by relying on locally sourced forestry waste such as pine beetle kill.

Q. HOW DO THE IDENTIFIED REINVESTMENT CONCEPTS AT HAYDEN ACHIEVE THE ECONOMIC PROSPERITY BENEFIT?

A. As discussed further by Company witness Ms. Velasquez Horvath in her Direct Testimony, these projects could provide significant, sustainable, long term reinvestment to the Hayden community and are intended to offset the lost tax revenues associated with the early retirement of the Hayden generating station. These new facilities could also help to retain existing jobs and provide future career opportunities to this area of the state.

Q. HOW DO THE IDENTIFIED REINVESTMENT CONCEPTS AT HAYDEN INSULATE PUBLIC SERVICE'S CUSTOMERS FROM FUEL COST INCREASES?

A. Both molten salt and solar electrolysis can rely on low cost system energy or no fuel cost renewable energy for generation. Biomass relies upon locally sourced forest waste products for fuel, such as beetle kill, and these products are not tied to natural gas or coal supply markets as most dispatchable resources are today. However, the emission reduction benefits or firm capacity benefits might need to be considered (e.g., through application of the social cost of carbon as with other resources in the ERP) in the planning of these resources as the fuel costs are unlikely to be lower than competing conventional resources such as natural gas-fired generation or variable renewable generation such as solar and wind.

Q. HOW DO THE IDENTIFIED REINVESTMENT CONCEPTS ACHIEVE THE ENVIRONMENTAL PROTECTION BENEFIT?

A. Three of the projects are zero or low carbon resources, which support the State's and the Company's goal for a carbon-free future. Furthermore, the proposed biomass facility directly supports the State's efforts to mitigate wildfire risk by helping reduce the amount of pine beetle kill and other forest waste products that help to fuel the wildfires that have devasted much of the State over the last decade.

Q. MOVING AWAY FROM THE HAYDEN EXAMPLE, COULD SECTION 123 BE USED TO SELECT OTHER ADVANCED TECHNOLOGIES IN THIS ERP?

A. Yes, I think so. Section 123 could be a tool used to promote the development, advancement, or commercialization of affordable, carbon-free, 24/7 power technology options that our 2050 emission reduction target, and the State of Colorado's broader GHG emission reduction goals, depend on. Moreover, as stated at the beginning of this section, action by the General Assembly to provide pathways to advance these types of resources—while also addressing just transition considerations—would be useful to propel the Company towards the carbon-free future we want to achieve for our customers and the State.

IX. RECOMMENDATIONS AND APPROVALS REQUESTED

Q. WHAT IS THE COMPANY REQUESTING THE COMMISSION APPROVE UNDER THIS APPLICATION?

A. In sum, Public Service has presented a comprehensive 2021 ERP & CEP for the Commission's consideration. The Company accordingly requests that the Commission approve Phase I of the Company's 2021 ERP & CEP and make the following specific approvals, findings, and determinations:

- We request that the Commission grant approval of our 2021 ERP & CEP (Attachment AKJ-1 through AKJ-3), inclusive of the following sub-approvals.
  - Approval of the Company's proposed Phase II all-source competitive acquisition and bid evaluation process to acquire generation resources to meet the Company's resource needs in this proceeding.
  - Approval of the RFPs and model contracts set forth in Volume III (Attachment AKJ-3);
  - Approval of the modeling inputs, assumptions, and methodologies included in the Company's Phase I filing;
  - Approval of the updated studies to be used in the Phase II bid evaluation process, including the:
    - Planning Reserve Margin Study;
    - Wind and Solar Integration Study;
    - Effective Load Carrying Capability Study; and
    - Flex Reserve Study and Supplemental Flex Reserve Study.
  - Approval of the Company's preferred coal action plan, including approval to:
    - Accelerate the retirement of Hayden 2 to 2027 and Hayden 1 to 2028 consistent with the agreement reached among the joint owners;
    - Accelerate the retirement of Craig 2 to September 30, 2028 consistent with the agreement reached among the joint owners;

        - Convert Pawnee from coal to natural gas by the end of 2028; and
        - Reduce operations of Comanche 3 to an approximately 33 percent capacity factor beginning in 2030 and accelerate retirement of the unit to 2040.
    - A finding that coal cycling costs are not a necessary model input for the Phase II bid evaluation;
- Approval of the regulatory asset recovery method for: Craig 2; Hayden 1; Hayden 2; and the retired portion of Pawnee.
- A finding that the Company's plan to securitize the costs associated with the accelerated retirement of Comanche 3 is reasonable and in the public interest to enable the Company to begin a series of actions over the next two decades to effectuate the securitized refinancing, which will involve subsequent regulatory filings and Commission approvals;
- Approval of the proposed "time fence" and associated locking of certain resources consistent with the RESA, as well as approval of the recording of incremental costs based upon a calculation of the average avoided cost determined by resource type as determined in this Phase I proceeding.
- Approval to initiate the CEPR after the issuance of the Phase II decision in this proceeding.
- Approval of deferred accounting of ERP-related expenses, including legal costs and consultants.
- Approval of the Emissions Reduction Performance Incentive Mechanism.
- A finding that the Commission recognizes the financial implications of adding stand-alone battery storage resources in this ERP and accordingly authorizes future rate base inclusion of capital leases as necessary to effectuate the acquisition of certain stand-alone battery resources. Alternatively, the Company requests the Commission affirmatively state that it will not accept bids for unrestricted stand-alone battery storage resources in the competitive solicitation.
- A finding that the Commission encourages the Company to investigate the feasibility of certain long-lead time generation resources to achieve carbon reductions beyond 2030 and authorize certain ratemaking treatment for associated costs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Jack W. Ihle

Jack Ihle is Director of Regulatory & Strategy Analysis for Xcel Energy – Colorado. He leads a team responsible for regulatory aspects of resource planning, renewable energy planning, electric vehicles and other policy issues. Mr. Ihle has participated in Public Service Company of Colorado's last four resource plans. He has testified before the Colorado Public Utilities Commission, the Colorado Legislature, the Minnesota Legislature, and the New Mexico Environmental Improvement Board.

Mr. Ihle previously worked in environmental policy for ten years, most recently serving as Director of Environmental Policy while leading Xcel Energy's climate policy, environmental policy and environmental communications efforts across the Company's eight states. Mr. Ihle has also served in energy consulting roles with IHS Markit and Platts, focusing on renewable energy, climate policy and forecasting engagements.

Mr. Ihle has a Master of Science degree in Energy & Resources from the University of California at Berkeley, and a Bachelor of Arts degree in Political Science from Bowling Green State University. He serves on the board of directors for Volunteers for Outdoor Colorado, and has previously served on the boards of the Regional Air Quality Council, XPAC, the Solar Technology Acceleration Center and WEST Associates.