**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	**)**
	)

<u>DIRECT TESTIMONY OF JAMES F. HILL</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 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN	**) PROCEEDING NO. 21A-____E**

<u>DIRECT TESTIMONY OF JAMES F. HILL</u>

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
2021 ERP & CEP	2021 Electric Resource Plan and Clean Energy Plan
CC	Combined Cycle
CEP	Clean Energy Plan
CO_2	Carbon Dioxide
CPCN	Certificate of Public Convenience and Necessity
CPUC	Colorado Public Utilities Commission
DG	Distributed Generation
DSM	Demand Side Management
ERP	Electric Resource Plan
IPP	Independent Power Producer
kW	Kilowatt
kWh	Kilowatt-hour
L&R	Load and Resource
LOLP	Loss of Load Probability
MWh	Megawatt hour
PPA	Power Purchase Agreement
Public Service or Company	Public Service Company of Colorado
PV	Photovoltaic
PVRR	Present Value Revenue Requirement
RAP	Resource Acquisition Period

RECs	Renewable Energy Credits
RE Plan	Renewable Energy Plan
RES	Renewable Energy Standard
RESA	Renewable Energy Standard Adjustment
Retail DG	Retail Distributed Generation
RFP	Request for Proposal
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

* * * *

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 OF JAMES F. HILL</u>

I. <u>INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James F. Hill. My business address is 1800 Larimer Street, Denver, Colorado 80202.

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

A. I am employed by Xcel Energy Services Inc. ("XES") as Director, Resource Planning. XES is a wholly-owned subsidiary of Xcel Energy Inc. ("Xcel Energy"), and provides an array of support services to Public Service Company of Colorado ("Public Service" or "Company") and the other three utility operating company subsidiaries of Xcel Energy on a coordinated basis.

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 the Director, Resource Planning, I am responsible for overseeing the Company's resource planning and competitive resource acquisition processes, as well as the various technical analyses on the generation resource options that are available to Xcel Energy's operating companies for meeting customer demand. A description of my qualifications, duties, and responsibilities is included at the end of my Direct Testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to support the Company's 2021 Electric Resource Plan and Clean Energy Plan ("2021 ERP & CEP") from a resource planning perspective. I provide an overview of the Electric Resource Plan ("ERP") process in general, and then I discuss how the Company developed and modeled various portfolios and coal actions. I provide the results of the Company's Phase I portfolio analysis and discuss the Company's selection of its preferred plan.

Q. BEFORE DESCRIBING THE ORGANIZATION OF YOUR TESTIMONY, CAN YOU SUMMARIZE THE COMPANY'S PREFERRED CEP?

A. Yes. For the reasons I discuss in my Direct Testimony, the Company's preferred Clean Energy Plan ("CEP") is portfolio "SCC 7". The preferred plan portfolio is one that has been optimized using the social cost of carbon ("SCC") rather than $0/ton for carbon. Specifically, the coal actions of the preferred plan (SCC 7) include:

1. Early retirement of Craig 2 in 2028 and Hayden 1 in 2028 and Hayden 2 in 2027;
2. Conversion of Pawnee to burn natural gas by 2028; and
3. Reducing generation from Comanche 3 to a level representative of a 33 percent annual capacity factor beginning in 2030 and early retiring the unit in 2040.

Coupled with these coal actions, the preferred plan includes indicative levels of generic wind, solar, storage, and firm and flexible dispatchable resources of approximately 2,300 megawatts ("MW"), 1,600 MW, 400 MW, and 1,300 MW, respectively. The actual level and composition of these and other resource technologies in the preferred plan will be determined through the Phase II competitive solicitation and bid evaluation process.

Q. HOW IS THE REST OF YOUR TESTIMONY ORGANIZED?

A. In Section II, I set the stage by providing an overview of the ERP process, including a description of the two phases of an ERP proceeding: Phase I and Phase II. I also describe two key factors that materially influenced the preparation of this Phase I 2021 ERP & CEP, including: (1) the requirement that our generation portfolio(s) must achieve specific clean energy targets as a result of the passage of Senate Bill 19-236 ("SB 19-236"); and (2) the requirement of SB 19-236 to use the social cost of carbon in the optimization of resource planning portfolios in our modeling.

In Section III, I discuss the resource acquisition period ("RAP") and planning period used for this 2021 ERP & CEP. SB 19-236 requires that the Company use a RAP through 2030 to align with the clean energy target of 80 percent emission reduction by 2030 from 2005 levels. The Company proposes a planning period from 2021 through 2055.

In Section IV, I explain how the Company conducted its assessment of the need for additional generation resources over the RAP. Specifically, I discuss the five key areas that factor into the assessment of resource need, including: (1) generation capacity needs; (2) generation needed to reduce emissions; (3) the need for flexible generation resources; (4) dispatchable resource needs for system reliability; and (5) the need for additional resources to comply with the Renewable Energy Standard ("RES").

In Section V, I explain how we developed the "ERP portfolios" and the "CEP portfolios" for purposes of this Phase I filing. Specifically, I explain that the ERP portfolios were developed to meet the base resource need, (i.e., the needs reflected in our load forecast inclusive of the previously announced accelerated retirements of Craig 2, Hayden 1, and Hayden 2), and how they are not required within the modeling to meet the clean energy target in 2030. In contrast, I explain that the CEP portfolios reflect additional coal transitions at Pawnee and Comanche 3 and additional resource acquisitions that are required to meet the 80 percent clean energy target established by SB 19-236. Next, I step through the framework used for the analysis of the ERP and CEP portfolios and explain the various coal actions and combinations of actions considered in the analysis.

In Section VI, I explain the results of the ERP and CEP portfolio optimizations using the SCC. Specifically, I describe the generic resources that were optimized, the estimated potential infrastructure investment, the incremental costs/benefits, the projected rate impact, and the carbon reduction efficiency associated with each of the ERP and CEP SCC portfolios.

In Section VII, I explain the results of the ERP and CEP portfolio optimizations using an assumption that the cost for each ton of carbon emitted has a $0/ton cost. I describe the results using the same framework as laid out in Section VI.

In Section VIII, I discuss the Company's conclusions from the ERP and CEP portfolio analysis and explain the various factors that influenced the Company's selection of SCC 7 as its preferred plan.

In Section IX, I discuss the various sensitivities performed by the Company to further analyze the ERP and CEP portfolios. These sensitivity analyses involve changing a single key input assumption and assessing how that change impacts a portfolio's carbon cost (i.e., repricing sensitivity) or the composition of resources added within the portfolio (i.e., reoptimized sensitivity). The primary purpose of sensitivity analyses is to test the robustness of the Company's selection of SCC 7 as our preferred plan under different futures. I discuss a few of the more informative sensitivity analysis results and note that a more detailed discussion is provided in Volume 2 of the Company's ERP.[1]

In Section XI, I explain that, consistent with the requirements of SB 19-236 and past practice, the Company is proposing to utilize an All-Source competitive solicitation process in Phase II to acquire the resources necessary to meet the

[1] Volume 2 is included as Attachment AKJ-2 to the Direct Testimony of Company witness Ms. Alice K. Jackson.

various needs and objectives of this 2021 ERP. I note that the use of competitive procurement is the foundation of the successful ERP paradigm in Colorado. I also summarize specific reliability requirements that the Company proposes be employed in the evaluation and selection of Phase II bids.

Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR DIRECT TESTIMONY?

A. No.

II. OVERVIEW OF PUBLIC SERVICE'S RESOURCE PLANNING PROCESS

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

A. In this section of my Direct Testimony, I provide an overview of the ERP process, the objectives of the Company's 2021 ERP & CEP, and a discussion of how the 2021 ERP & CEP compares to the Company's last 2016 ERP.

Q. DOES THE COMMISSION REQUIRE PUBLIC SERVICE TO DEVELOP AND FILE AN ERP?

A. Yes. The Commission has established rules requiring electric utilities to develop and file ERPs generally on a four-year cycle. The Commission's rules specify what must be contained in electric utilities' ERPs and the process electric utilities must undertake to implement their ERPs. The Colorado ERP process is looked to nationally as a model for the acquisition of cost effective and increasingly clean generation resources. As I will describe in this section of my Direct Testimony, the Company intends to utilize this process to advance the State of Colorado toward its emission reduction goals—as contemplated by the General Assembly with the passage of SB 19-236.

Q. WHAT IS THE GENERAL OBJECTIVE OF AN ERP?

A. As specified by the Commission's rules, the ERP process focuses on identifying additional generation resources or changes to existing generation resources that are needed to meet certain future objectives in a cost effective and reliable manner.[2] An ERP consists of two phases: Phase I and Phase II.

Q. PLEASE DESCRIBE PHASE I OF THE ERP PROCESS.

A. Phase I identifies generation resource needs (including quantities and generation resource types) that will meet specified objectives. Examples of objectives in an ERP include acquiring new generation to meet growing customer demand for power (i.e., the amount not served by Demand Side Management ("DSM") or Distributed Energy Resources ("DERs")), new resources to meet RES requirements, new resources to take advantage of Federal tax credits to help reduce costs to customers, and new resource additions or retirements to meet environmental objectives such as emission reduction or clean energy targets.

Q. PLEASE DESCRIBE PHASE II OF THE ERP PROCESS.

A. In Phase II, the Company implements a competitive acquisition process for new resources. Public Service evaluates and develops portfolios of bids that meet the Commission's Phase I directives (overseen by an independent evaluator) for Commission consideration. Through a Phase II decision, the Commission ultimately selects specific resources to satisfy the resource needs. The Company then pursues the acquisitions of those generation resources through follow-on Certificate of Public Convenience and Necessity ("CPCN") proceedings and Power Purchase Agreement ("PPA") negotiations. I would also note that for this ERP, where specific legislation (i.e., SB 19-236) directs the inclusion of a Clean Energy Plan, Phase I will also evaluate potential actions with the

[2] *See* 4 CCR 723-3-3600, *et seq.*

Company's remaining coal fleet. Through this Phase I process, the Company is seeking—along with approval of modeling inputs, assumptions, methodologies, and its 2021 ERP & CEP—approval of a specific set of actions to the existing coal fleet to ensure the right resource need is filled in the Phase II competitive solicitation.

Q. IS THE 2021 ERP & CEP DIFFERENT IN ANY REGARD IN COMPARISON TO THE 2016 ERP THAT RESULTED IN THE COLORADO ENERGY PLAN?

A. Yes. The 2021 ERP & CEP is the first ERP cycle with specific clean energy targets that our generation portfolio(s) must meet as a result of the passage of SB 19-236. Specifically, the Company is required to file a plan that achieves an 80 percent carbon dioxide emission reduction from 2005 levels by 2030, which equates to a plan that emits approximately 5.4 million short tons ("MST") of carbon dioxide emissions in 2030. This emission constraint changes the ERP process in some ways because it is the first time we have done resource planning and modeling for Public Service Company with a specific emission cap in place. This planning process is also different because we are using the social cost of carbon in the optimization of resource planning portfolios in our EnCompass modeling.[3] This value has been used as a sensitivity in previous ERPs, but in this plan we are including it in the optimization of portfolios as directed by SB 19-236. The modeling of portfolios to meet statutory clean energy targets and use of the SCC in the modeling are two foundational changes from

[3] Please refer to the Direct Testimony of Mr. Jon T. Landrum for a discussion of the Company's modeling process and assumptions.

SB 19-236 that materially influenced the preparation of this Phase I 2021 ERP & CEP.

III. RESOURCE ACQUISITION PERIOD AND PLANNING PERIOD

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

A. In this section of my Direct Testimony, I discuss the RAP and planning period that the Company proposes to use for this 2021 ERP & CEP.

Q. WHAT IS THE SIGNIFICANCE OF THE RESOURCE ACQUISITION PERIOD OR "RAP"?

A. The RAP is the period of time over which the utility acquires specific generation resources to meet projected resource needs. Typically, the Commission's ERP rules allow jurisdictional utilities to select a RAP between six and ten years from the date the plan is filed.

Q. DOES SB 19-236 ESTABLISH THE RAP TO BE USED WHEN A UTILITY'S ERP CONTAINS A CEP?

A. Yes. SB 19-236 requires the ERP containing the CEP to utilize a RAP that extends through 2030. Since the 2021 ERP contains the Company's CEP, the Company will utilize a RAP for the 2021 ERP & CEP that covers years 2021 through 2030. This RAP will be applied to both ERP portfolios and CEP portfolios. I address the difference between "ERP portfolios" and "CEP portfolios" in more detail later in my Direct Testimony.

Q. WHAT IS THE SIGNIFICANCE OF THE PLANNING PERIOD?

A. The "planning period" represents the future period for which a utility develops its plan, and the period over which the costs and benefits of new resources are evaluated by the utility. The planning period also defines the time over which net present value of revenue requirements and emission costs for resources are calculated.

In establishing the proposed planning period, the Company sought to comply with existing ERP rules but also take guidance from discussions around the planning period in the not finalized rulemaking proceeding in Proceeding No. 19R-0096E. Based on this approach, we analyzed a "planning period" of 20 to 40 years and beginning no later than January 1 following the date the utility files its plan with the Commission. The planning periods considered by the Company extended either through the 20-year period following the last year of the RAP or extended beyond the RAP for a period equal to the longest proposed contract term length.

Q. WHAT CONTRACT TERM LENGTH IS THE COMPANY PROPOSING IN ITS PHASE II REQUEST FOR PROPOSALS?

A. We are proposing contract term lengths up to 25 years.[4]

Q. WHAT PLANNING PERIOD IS THE COMPANY RECOMMENDING?

A. Public Service proposes a planning period from the plan filing year of 2021 extending through 2055, or approximately 35 years, which represents the period following the last year of the RAP (i.e., 2030) through the last year of the proposed 25-year contract term length in the model contracts filed in Volume 3 of our ERP.

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[4] The contract term lengths are based in part on avoiding or minimizing adverse financial impacts of imputed debt, finance lease, and variable interest entity-related obligations.

IV. ASSESSMENT OF RESOURCE NEED: ERP AND CLEAN ENERGY PLAN

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

A. In this section of my Direct Testimony, I explain how the Company conducts its assessment of the need for additional generation resources over the RAP. Specifically, I discuss the five key areas that factor into the assessment of resource need, including: (1) generation capacity needs; (2) generation needed to reduce emissions; (3) the need for flexible generation resources; (4) dispatchable resource needs for system reliability; and (5) the need for additional resources to comply with the RES.

Q. DOES SB 19-236 OUTLINE SPECIFIC REQUIREMENTS REGARDING THE COMPANY'S ASSESSMENT OF RESOURCE NEED?

A. Yes. SB 19-236 requires the Company to clearly distinguish between: (1) the resources necessary to meet customer demands in the RAP; and (2) the additional resource need created by actions taken to meet the 80 percent clean energy target (e.g., retirement of existing generating facilities, changes in system operations, etc.).

Q. HOW DOES THE COMPANY DISTINGUISH BETWEEN THESE TWO CATEGORIES OF RESOURCE NEED IN ITS PHASE I ANALYSIS?

A. As I will discuss in more detail in Section V of my Direct Testimony, the Company developed "ERP portfolios" and "CEP portfolios" to clearly distinguish between these two resource needs, as required by SB 19-236. The ERP portfolios meet what I refer to as the base need, i.e., the needs reflected in our load and resource balance inclusive of the previously announced retirements of Craig 2, Hayden 1, and Hayden 2. ERP portfolios are not required within the modeling to meet the 80 percent emission reduction target in 2030. In contrast, CEP portfolios reflect additional coal actions at Pawnee and Comanche 3 and the additional resource acquisitions required to meet the 80 percent emission reduction target in 2030, as established by SB 19-236.

Q. PLEASE SUMMARIZE THE COMPANY'S ASSESSMENT OF THE NEED FOR ADDITIONAL GENERATION RESOURCES.

A. The assessment of need is focused on five areas:

1. Generation capacity needs for system reliability;
2. Generation needed to reduce emissions;
3. Flexible resource needs for integrating intermittent resources;
4. Dispatchable resource needs for system reliability; and
5. Resources needed to comply with the RES.

The results of these assessments identified: (1) no need in years 2021 through 2025 for additional generation capacity to maintain acceptable system reliability, and increasing needs for each year from 2026 to 2030; (2) no need for additional renewable resources for the purpose of meeting the "minimum amounts" reflected in the percentage requirements of the RES;[5] (3) the Flex Reserve Study work identifies the volume of flexible resources needed to accommodate up to three gigawatts ("GW") of incremental wind generation; and

(4) a need for additional emission reduction efforts to meet the statutory clean energy target of SB 19-236.

A. Generation Capacity Needs

Q. HOW DID PUBLIC SERVICE ASSESS WHETHER ADDITIONAL GENERATION CAPACITY IS NEEDED FOR SYSTEM RELIABILITY PURPOSES?

A. We forecast whether sufficient planning reserve margin would be maintained throughout each summer peak season during the RAP to make this determination. The peak electric demand forecast discussed in the Direct Testimony of Company witness Mr. John M. Goodenough is compared with the existing and planned generation resources. This is commonly referred to as the load and resource balance or, load and resource table ("L&R").

Q. PLEASE EXPLAIN THE PLANNING RESERVE MARGIN.

A. Planning reserve margin is the amount of generation capability in excess of peak firm obligation load that a utility carries on its system in order to meet customer demand under system uncertainties. The Company proposes utilizing an 18 percent planning reserve margin for purposes of acquiring resources in Phase II of this 2021 ERP.

Q. WHAT IS THE BASIS FOR AN 18 PERCENT PLANNING RESERVE MARGIN?

A. The 18 percent planning reserve margin is the result of a updated planning reserve margin study that was performed by Astrapé Consulting for Public

[5] No additional wholesale DG or non-DG resources are needed to comply with the RES through 2030 and beyond. The need for additional retail-DG resources are determined in the Company's Renewable

Service in accordance with Commission directives from the 2016 ERP in Proceeding No. 16A-0396E.[6] The updated planning reserve margin study is discussed in detail in the Direct Testimony of Company witness Mr. Kevin D. Carden of Astrapé Consulting and is provided as Attachment KDC-1 to Mr. Carden's Direct Testimony.

Q. HOW ARE THE EFFECTS OF THE COMPANY'S DEMAND SIDE MANAGEMENT PROGRAMS ACCOUNTED FOR IN THE LOAD AND RESOURCE BALANCE?

A. Consistent with prior ERPs, the forecast of summer peak load is reduced by the combined effects of the Company's DSM programs,[7] based on goals approved by the Commission in other proceedings. Company witness Mr. Jack W. Ihle addresses the interactions of the ERP with other planning processes (i.e., DERs, DSM, etc.). After accounting for DSM programs, the resulting load is referred to as firm obligation load. The 18 percent planning reserve margin is applied to the forecast of firm obligation load for each year of the RAP.

Q. WHAT IS THE COMPANY'S CURRENT ASSESSED NEED FOR ADDITIONAL GENERATION CAPACITY OVER THE RAP TO MEET THE PROPOSED 18 PERCENT PLANNING RESERVE MARGIN?

A. Table JFH-D-1 below summarizes the load and resource balance forecast of summer capacity needs for years 2021-2030 (i.e., the RAP) needed to meet the 18 percent planning reserve margin. Two capacity need forecasts are provided

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Energy Plan filings.

[6] *See* Decision No. C17-0316, at ¶49 and Ordering ¶5 in Proceeding No. 16A-0396E.

in Table JFH-D-1: (1) a starting level of need in which the capacity of all currently operating coal units are included through 2030;[8] and (2) a capacity need reflecting the impact of recently announced coal unit retirements ahead of schedule at Craig 2, Hayden 1, and Hayden 2, respectively. A more detailed load and resource balance is included in Section 2.12 of ERP Volume 2.

Table JFH-D-1 Generation Capacity Needs (MW)
(needs as of summer of year shown)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Starting Capacity Need long/(short)	**102**	**296**	**210**	**61**	**17**	**(203)**	**(672)**	**(1,354)**	**(1,411)**	**(1,474)**
Announced early coal retirements:										
Craig 2									(40)	(40)
Hayden 1									(135)	(135)
Hayden 2								(98)	(98)	(98)
Capacity Need with announced retirements long/(short)	**102**	**296**	**210**	**61**	**17**	**(203)**	**(672)**	**(1,452)**	**1,684)**	**(1,747)**

Q. DOES THE LOAD AND RESOURCE BALANCE IN TABLE JFH-D-1 REFLECT THE CAPACITY NEEDS ASSOCIATED WITH THE COMPANY'S COAL TRANSITION AS PART OF THE PREFERRED CLEAN ENERGY PLAN?

A. Yes.[9] The Company's preferred CEP includes the retirements of Craig 2, Hayden 1, and Hayden 2 earlier than currently scheduled, and the capacities for those respective facilities have been included in the need demonstrated above.

[7] DSM includes energy efficiency, demand response, and interruptible programs.
[8] Table JFH-D-1 includes only Public Service's share of Comanche 1, Craig 2, Hayden 1 and Hayden 2.
[9] The capacity needs projected in Table JFH-D-1 are calculated assuming the 72 MW Hartsel solar facility (34 MW ELCC) is successfully brought on-line by December 31, 2022. At the time of this filing, Park County has denied necessary permits for the project to proceed to construction. The Company will continue to monitor this situation and if needed, remove the project MWs from the Phase II L&R calculation of capacity needs.

However, the preferred CEP retains the same level of generation capacity for Pawnee (505 MW) and Comanche 3 (500 MW Company share) through 2030.

Q. HOW DO THE RESOURCE NEEDS IN TABLE JFH-D-1 ABOVE, WHICH FOCUS ON SUMMER PEAK LOADS, COMPARE WITH RESOURCE NEEDS BASED ON WINTER PEAK LOADS?

A. From a winter capacity need perspective, our assessment shows no capacity needs for years 2021-2026 with increasing needs each year from 2027-2030.

Q. DOES THE COMPANY INTEND TO UPDATE THIS LOAD AND RESOURCE BALANCE PRIOR TO THE PHASE II ACQUISITION PROCESS?

A. Yes. Public Service will, prior to receipt of proposals in the 2021 ERP Phase II competitive acquisition process, update the load and resource balance using the most current forecasts of peak demand and generation supply—as well as any resource-related impacts of the Commission’s Phase I decision or other pending proceedings. The RAP capacity needs that will be identified in that updated load and resource balance will establish the level of additional generation resources to be acquired through the Phase II competitive acquisition process to meet the Company’s resource need, inclusive of a planning reserve margin of 18 percent. By updating the load and resource balance in this manner, the Company will better ensure that we acquire a sufficient amount of generation resources to reliably serve the peak demands during the RAP.

Q. HAS THE COMPANY USED A SIMILAR APPROACH IN PRIOR ERP PROCESSES?

A. Yes. This approach to update the load and resource balance prior to the Phase II competitive acquisition process is consistent with the approach taken in the 2007, 2011, and 2016 ERPs. However, the acquisition of additional resources to meet our capacity needs in the RAP of this resource plan is just part of the picture; the more impactful driver of resource needs in the RAP are associated with the need to achieve the emission reduction targets of SB 19-236, as I discuss in the next section of my Direct Testimony.

B. Generation Needed to Reduce Emissions

Q. HOW DID PUBLIC SERVICE ASSESS WHETHER ADDITIONAL GENERATION RESOURCES ARE NEEDED TO COMPLY WITH THE 80 PERCENT CLEAN ENERGY TARGET ESTABLISHED IN SB 19-236?

A. We used the EnCompass computer model to develop a set of optimized indicative resource plan portfolios that would meet the projected resource needs of the Company for years 2021-2030 along with the estimated costs of those plans over a 2021-2055 planning period. These portfolios were optimized to meet the Company's planning reserve margin target (and other reliability requirements) *and* achieve the 80 percent emission reduction by 2030 from 2005 levels, using the baseline and target established by the Colorado Department of Public Health and Environment's Air Pollution Control Division and explained in more detail by Company witness Ms. Lauren W. Quillian. We refer to these portfolios as Clean Energy Plan or CEP portfolios. Portfolios were developed using two different assumptions for the cost of carbon emissions: (1) the social cost of carbon as delineated in SB 19-236 and explained in more detail by Company witness Mr. Jon T. Landrum; and (2) a $0/ton assumption. A detailed discussion on how these indicative resource portfolios were developed is included in Section 2.13 of ERP Volume 2. With this approach we have captured two different planning paradigms, one with a cost placed on carbon emissions, and one where there is no cost placed on carbon emissions.

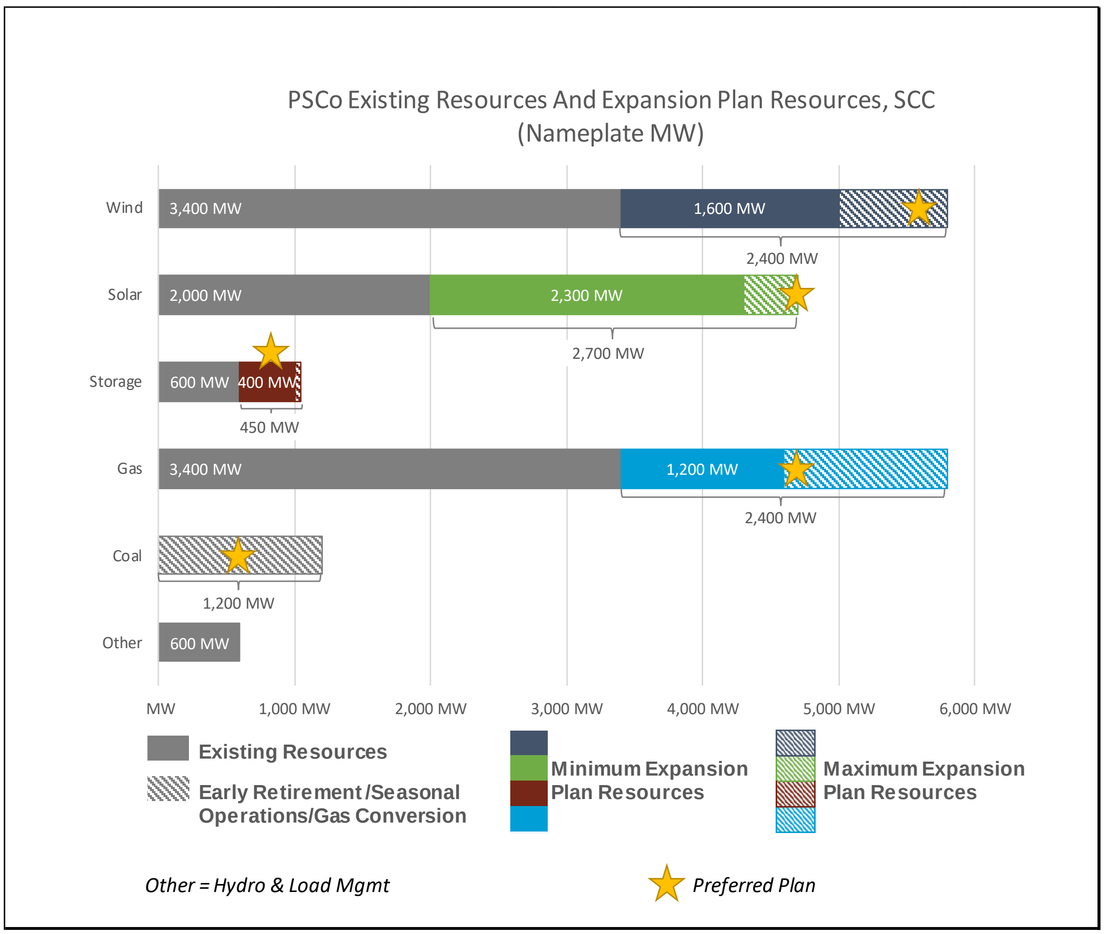
Q. HOW DID THE COMPANY REFLECT ESTIMATES FOR THE COST AND PERFORMANCE OF FUTURE GENERATION RESOURCES THAT COULD BE ADDED TO THE SYSTEM THROUGH THE PHASE II PROCESS IN THESE INDICATIVE PORTFOLIOS?

A. We developed a suite of what we refer to as "generic resource" representations to serve as proxies for actual bids the Company might expect to receive in the Phase II competitive solicitation. I discuss these generic resources in more detail later in my testimony.

Q. WHAT WERE THE RESULTS OF THE COMPANY'S ASSESSMENT OF RESOURCES NEEDED TO ACHIEVE 80 PERCENT CO2 EMISSION REDUCTIONS BY 2030?

A. Indicative resource portfolios developed using the SCC included approximately: 1,800-2,400 MW of additional wind generation resources; 2,400-2,700 MW of additional solar generation resources (inclusive of both distributed solar and utility scale solar); 400 MW of additional storage resources; and 1,500-2,300 MW of new firm fueled and flexible dispatchable generation resources. The additional resources of the Company's preferred CEP portfolio (SCC 7) includes approximately: 2,300 MW of wind; 1,200 MW of distributed solar; 1,600 MW of utility scale solar; 400 MW of storage; and 1,300 MW of additional firm fueled and flexible dispatchable generation. I discuss the results of our analysis of ERP and CEP portfolios later in my testimony, but I think Figure JFH-D-1 below duplicated from Ms. Alice K. Jackson's Direct Testimony provides a helpful illustration as to the portfolios we looked at and where the preferred plan falls:

FIGURE JFH-D-1



Q. WHY DO YOU REFER TO THESE PORTFOLIOS DEVELOPED USING THE ENCOMPASS MODEL AS "INDICATIVE"?

A. The ERP and CEP portfolios presented in Phase I of this proceeding were developed using "generic" representations[10] for the cost and performance of wind, solar, storage, gas combustion turbine ("CT"), and gas combined cycle ("CC") generation technologies. These generic representations are used in the Phase I modeling as a proxy for actual bids that the Company might receive in the Phase II competitive solicitation process that will take place in a year or so. As a result, ERP and CEP portfolios built from generic resources are referred to as "indicative." The timing, total nameplate amounts, and mix of new wind, solar, storage, gas CTs, and gas CCs in these indicative portfolios will undoubtedly change in the Phase II process when ERP and CEP portfolios are developed from actual bids with actual locations versus generic resource representations with no implied location. As in the last ERP cycle, and as explained in more detail by Company witness Ms. Jackson, we saw unexpected and cost-effective bids for solar plus storage technologies in the 2016 ERP Phase II competitive solicitation. I would expect to see similar outcomes and continued innovation and progress with resource technologies and pricing in Phase II of this ERP. Generally speaking, I expect the Phase II portfolios to include total nameplate

[10] See ERP Volume 2, Section 2.14 for a description of the cost and performance characteristics of the generic resources.

amounts that are directionally consistent with the levels of renewables, storage, and dispatchable resources included in the indicative Phase I portfolios.[11]

C. The Need for Flexible Generation Resources

Q. HOW HAS THE COMPANY ASSESSED THE NEED FOR FLEXIBLE RESOURCES TO HELP INTEGRATE WIND GENERATION ONTO THE COMPANY'S ELECTRIC SYSTEM?

A. The Company updated its analysis of Flex Reserve to accommodate current and incremental wind generation on its system. Company witness Mr. Kent L. Scholl discusses the details of this study work in his Direct Testimony. I will refer to this study report as the "2020 Flex Reserve Study."

Q. WERE THE RESULTS OF THE 2020 FLEX RESERVE STUDY INCORPORATED INTO THE MODELING OF ERP AND CEP PORTFOLIOS?

A. Yes. When optimizing ERP and CEP portfolios with the EnCompass model, one of the inputs captured in that modeling was a requirement that ERP and CEP portfolios contain the levels of flexible generation resources identified in the 2020 Flex Reserve Study work as a function of the total amount of wind generation (both existing and new) contained in each portfolio. Company witness Mr. Landrum discusses how this was accomplished in his Direct Testimony.

[11] Phase II portfolios are also expected to include levels of accredited capacity (i.e., ELCC) that are directionally consistent with the levels in the indicative Phase I portfolios.

Q. WILL THE RESULTS OF THE 2020 FLEX RESERVE STUDY BE INCORPORATED INTO THE PHASE II ERP AND CEP PORTFOLIOS THAT ARE DEVELOPED FROM ACTUAL BIDS?

A. Yes. The Commission's Phase I decision regarding this study will be incorporated into ERP and CEP portfolios developed in the Phase II process.

D. <u>**Dispatchable Resource Needs for System Reliability**</u>

Q. HOW HAS THE COMPANY ASSESSED THE NEED FOR DISPATCHABLE GENERATION RESOURCES TO HELP ENSURE THE GENERATION FLEET RETAINS THE ABILITY TO CONTINUALLY SERVE CUSTOMER LOAD?

A. The term dispatchable generation in this context refers to generation resources that system operators can start anytime, day or night. The output of these generation resources can be ramped up or down as needed—i.e., dispatched—and can operate continuously for many days regardless of local meteorological conditions.

The need to maintain a sufficient amount of dispatchable generation resources was assessed through the following efforts:

1. Within the EnCompass modeling of ERP and CEP portfolios, operating reserve requirements and flex reserve requirements were input directly into the model to maintain a continued balance between hourly customer load and generation. As Mr. John T. Welch details in his Direct Testimony, the Company's Commercial Operations group conducted significant analysis of the hourly generation output from these EnCompass runs to ensure that the modeled operation of the Company's generation and storage resources were realistic and that the various reserve requirements were being adequately enforced by the model.

2. ERP Volume 2 (Section 2.11) documents a recent four-day long weather event in November 2015 in Colorado with virtually no wind generation output and significantly reduced solar generation output. That analysis

shows that, in the extreme scenario where there was no dispatchable generation available to the system, approximately 69,000 MW of 5-hour storage[12] would have been required to serve customer net load (net load = native load – renewable generation). By contrast, the analysis also shows that approximately 1,000 MW of 5-hour storage would have been required to serve customer net load if approximately 3,900 MW of dispatchable generation were available. This simple analysis shows that a combination of intermittent renewable, short-duration storage, and dispatchable generation work together efficiently to reliably meet customer load.

E. The Need for Additional Resources to Comply with the RES

Q. HOW DID PUBLIC SERVICE ASSESS WHETHER ADDITIONAL RENEWABLE RESOURCES ARE NEEDED TO COMPLY WITH THE "MINIMUM AMOUNTS" REFLECTED IN THE PERCENTAGE REQUIREMENTS OF THE RES?

A. We did so by comparing the forecast of wholesale distributed generation ("DG") (i.e., DG resources over 30 MW in nameplate capacity) and non-DG Renewable Energy Credits ("RECs") over time with the minimum percentage requirements in the RES statute and RES Rules. This comparison shows that the existing and planned wholesale DG and non-DG renewable resources will generate enough RECs to comply with the minimum amounts in the RES beyond 2030. Details about the Company's REC projections to meet the Retail DG requirement are included in the 2020-2021 RE Plan that was filed with the Commission on July 1, 2019 in Proceeding No. 19A-0369E.

[12] The results of the analysis were presented on a basis of 5-hour duration storage to align with the storage duration of the Company's existing Cabin Creek pumped hydro facility.

V. DEVELOPMENT OF PHASE I ERP AND CEP PORTFOLIOS

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

A. The purpose of this section of my Direct Testimony is to explain how we developed the ERP and CEP portfolios for purposes of this Phase I filing.

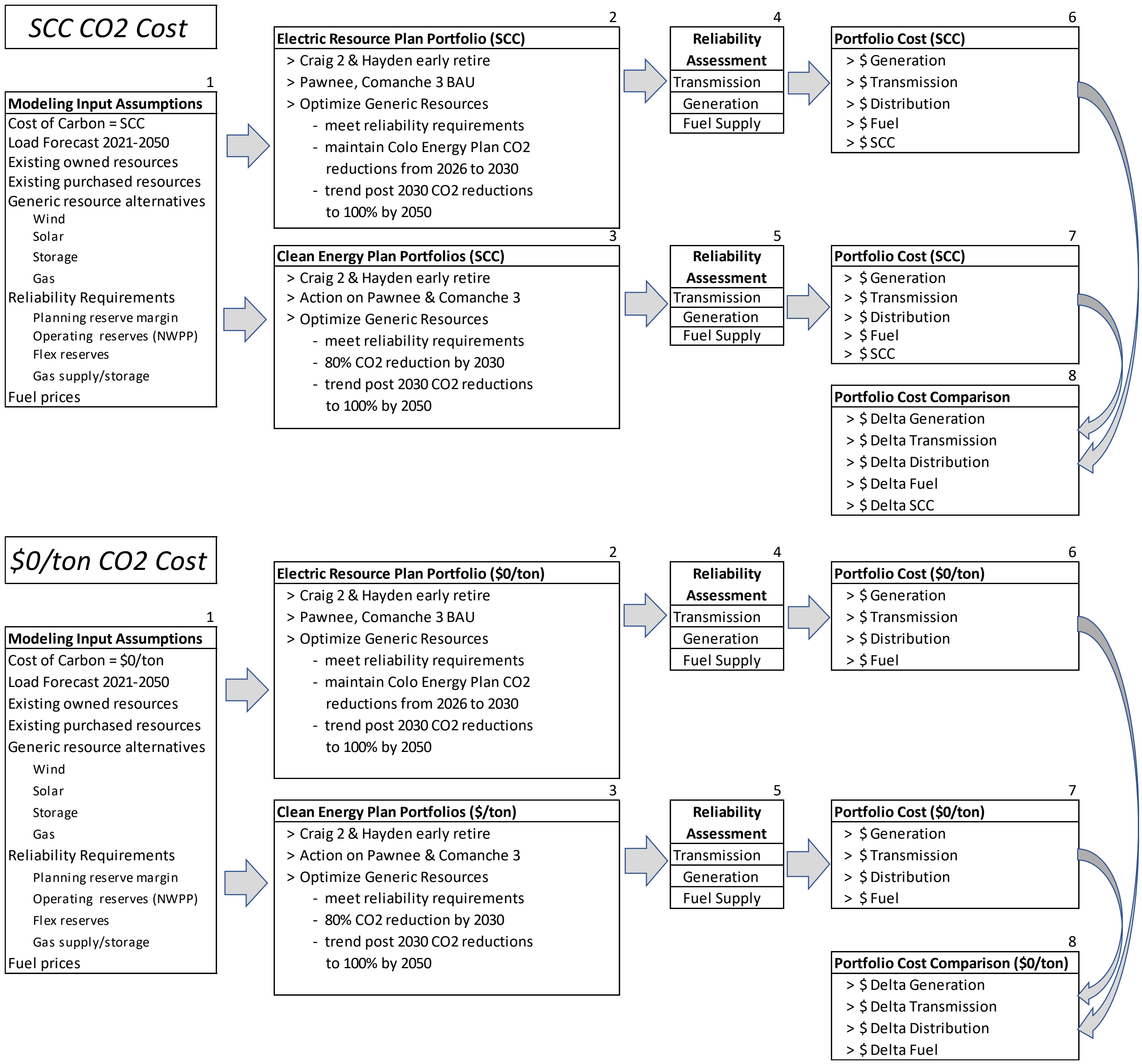
Q. BEFORE GOING INTO DETAIL ABOUT THE DEVELOPMENT PROCESS, WHAT IS AN ERP PORTFOLIO AND WHAT IS A CEP PORTFOLIO?

A. As I described briefly above, we developed ERP portfolios to meet the reference case need, i.e., the needs reflected in our load forecast inclusive of the previously announced accelerated retirements of Craig 2, Hayden 1, and Hayden 2. ERP portfolios are not required to meet the clean energy target within the modeling in 2030 for SB 19-236. In contrast, CEP portfolios reflect additional coal actions at Pawnee and Comanche 3 and additional resource acquisitions that are required to meet the 80 percent clean energy target established by SB 19-236. We applied similar portfolio distinctions in the last ERP cycle where we had Colorado Energy Plan portfolios that replaced Comanche 1 and Comanche 2 *and* portfolios that met a resource need assuming those units stayed online through the end of their book lives. We have in large part replicated the same approach here, consistent with the directives of SB 19-236.

Q. PLEASE DESCRIBE THE GENERAL PROCESS THE COMPANY EMPLOYED IN DEVELOPING THE ERP AND CEP PORTFOLIOS THAT ARE PRESENTED IN THIS PHASE I PROCEEDING.

A. We used the EnCompass computer model to develop a set of optimized resource plan portfolios that would meet the Company's projected resource needs and reliability requirements while reducing carbon emissions by at least 80 percent by 2030. These portfolios were optimized under two different assumptions for the cost of carbon emissions, as described above: (1) portfolios using the SCC; and (2) portfolios using a $0/ton carbon cost assumption. Figure JFH-D-2 below provides a high-level illustration as to the Company's analysis framework for creating these portfolios, and a detailed discussion on this process is included in Section 2.13 of ERP Volume 2.

Figure JFH-D-2 ERP and CEP Portfolio Analysis



Q. PLEASE DESCRIBE THE INFORMATION CONTAINED IN AN ERP OR CEP PORTFOLIO.

A. An ERP or CEP portfolio contains all the information needed to represent the characteristics and composition of the Public Service electric generation fleet for a given set of future assumptions for years 2021-2055. Some of the key assumptions are as follows:

1. A forecast of future electric customer load (wholesale and retail);
2. The cost, performance, and emission projections for existing generating units;
3. The cost, performance, and emission projections for potential future generation resource additions:
4. Forecasted fossil fuel prices;
5. Total system emission projections;
6. An estimate of cost for new transmission investment (recognizing that additional transmission investment will be necessary to interconnect portfolios evaluated in Phase II once generation locations are noted); and
7. Annual system revenue requirements.

Q. PLEASE DESCRIBE THE COAL ACTIONS THAT WERE CONSIDERED IN THE RESPECTIVE PORTFOLIOS.

A. I addressed this earlier in this section of my Direct Testimony but provide additional detail here. Both the ERP and CEP portfolios include the recently announced accelerated retirements of Craig 2 in 2028, Hayden 1 in 2028, and Hayden 2 in 2027. The Company also performed EnCompass modeling to inform the costs and benefits of the decisions to retire Craig 2 and Hayden 1 and 2 ahead of their scheduled business as usual ("BAU") retirement dates, as discussed in Section 2.13 of Volume 2. For the two remaining Company coal units, Pawnee and Comanche 3, all ERP portfolios assume continued operation of these coal units to 2041 and 2069, respectively (denoted as BAU below).[13] In contrast, CEP portfolios assess different combinations of coal actions on Pawnee and Comanche 3 as illustrated by combined or paired actions 2 through 8 in Table JFH-D-2. The various actions include combinations of accelerated retirements, gas conversions, and reduced operations beginning in 2030. By combining these actions in different ways, we have provided a diverse set of carbon emission reduction pathways toward the 2030 clean energy target.

Table JFH-D-2 Pawnee and Comanche 3 Actions

	Pawnee				Comanche 3				
Paired Action	Early Retire EOY 2028	Convert to Gas EOY 2027	Convert to Gas EOY 2024	BAU	Early Retire EOY 2029	Early Retire EOY 2039	Convert to Gas EOY 2027	Early Retire EOY 2039, Reduced Operations starting 2030	BAU
1				X					X
2	X				X				
3	X							X	
4		X					X		
5		X			X				
6		X				X			
7		X						X	
8			X					X	

Q. PLEASE DESCRIBE HOW CARBON EMISSIONS WERE REPRESENTED OR LIMITED IN THE CEP PORTFOLIOS?

A. All CEP portfolios were required to meet at—a minimum—the 80 percent clean energy target by 2030, while ERP portfolios were not required to do so. Both ERP and CEP portfolios were also required to achieve a 100 percent emission

[13] The revenue requirements for Comanche 3 for the 2021-2055 planning period modeled in EnCompass are based off depreciating the unit to a 2070 retirement date.

reduction by year 2050. Put another way, all portfolios are carbon-free by 2050—but the CEP portfolios achieve earlier reductions through additional actions on the coal fleet prior to 2030. Company witness Mr. Landrum discusses the modeling of emission constraints in his Direct Testimony.

Q. WHY DID THE COMPANY DEVELOP ERP PORTFOLIOS THAT DO NOT ACHIEVE THE 80 PERCENT CLEAN ENERGY TARGET ESTABLISHED IN SB 19-236?

A. ERP portfolios were needed for two primary reasons: (1) to provide a plan that focused on meeting the resource needs of the system absent the clean energy target, referred to herein as a “base need” or “ERP” portfolio; and (2) to serve as a cost foundation against which the costs and benefits of CEP portfolios are compared. The ERP portfolio concept is also helpful, as explained by Company witness Mr. Alexander G. Trowbridge, for purposes of establishing cost recovery through the statutory Clean Energy Plan Rider (“CEPR”).

Q. HOW DID THE COMPANY REFLECT ESTIMATES FOR FUTURE SUPPLY-SIDE GENERATION RESOURCES IN THESE INDICATIVE PORTFOLIOS?

A. ERP and CEP portfolios were developed within EnCompass from a suite of what we refer to as “generic resource” representations to serve as proxies for potential new supply-side generation resources, without regard to a specific location. These generic resource representations are meant to be indicative of what the Company might expect to receive in the Phase II competitive solicitation for this 2021 ERP & CEP. Generic resource representations were developed for wind, utility-scale solar, four-hour duration battery storage, gas-fired combined cycle, gas-fired combustion turbine (sometimes referred to as “simple cycle”), and gas-fired reciprocating engine technology. Wind, solar, and storage estimates were developed from the 2020 National Renewable Energy Laboratory Annual Technology Baseline. Gas-fired estimates were developed by employees within the Company’s engineering and construction department. Detailed information on the generic resource representations is contained in Section 2.14 of ERP Volume 2.

Q. HOW WERE SYSTEM RELIABILITY REQUIREMENTS FACTORED INTO THE DEVELOPMENT OF ERP AND CEP PORTFOLIOS?

A. As discussed in Section 2.9 of Volume 2, system reliability was factored into the development of portfolios in an iterative process that involved inputting various reliability requirements upfront into the EnCompass modeling process, post-modeling reliability review of model output/results, and then adjusting model inputs if needed and then rerunning the adjusted model.

Q. PLEASE DESCRIBE WHAT RELIABILITY REQUIREMENTS WERE REFLECTED AS INPUTS INTO THE ENCOMPASS MODELING PROCESS.

A. The results of technical studies regarding planning reserve requirements, flex reserve requirements, and ELCC capacity credit were applied within the EnCompass modeling of all portfolios.[14] In addition to the results of these technical studies, the operating requirements established by the Northwest

[14] See ERP Volume 2, Section 2.18 for these studies.

Power Pool ("NWPP") Reserve Sharing Group were reflected as inputs into the modeling process.[15]

Q. PLEASE DESCRIBE THE POST-MODELING RELIABILITY REVIEW PROCESS.

A. This process involved reviewing hourly model output for year 2030. A team of Company subject matter experts reviewed the overall generation composition of portfolios from both a generation reliability perspective and a transmission reliability perspective.

Q. PLEASE BRIEFLY DESCRIBE THE GENERATION RELIABILITY REVIEW PROCESS.

A. The hourly data review process for generation reliability involved an assessment of 8760 (i.e., the number of hours in a year) hourly model output to determine if the model was properly enforcing planning reserve, flex reserve, and NWPP operating reserve requirements. The review also analyzed whether the current gas supply system would be sufficient to reliably supply the hourly volumes and fluctuations in gas burns that the modeling predicted.

Q. PLEASE BRIEFLY DESCRIBE THE TRANSMISSION RELIABILITY REVIEW PROCESS.

A. The hourly data review process for real-time transmission reliability also involved an assessment of 8760 hourly model output. The purpose of the review was to determine if the current and planned transmission system could reliably deliver,

[15] As a member of the Northwest Power Pool ("NWPP") Reserve Sharing Group, Public Service carries operating reserves in accord with the NWPP established methodology.

in real-time, the output of the generation resources in each portfolio to customer load. In addition to this real-time assessment of hourly data, the Company's transmission reliability review and planning process to support this 2021 ERP & CEP filing involved an assessment of the Company's resource planning projections to determine if the planned transmission system expansion could reliably deliver the Company's resource acquisition target to meet the 2030 emission reduction goals.[16] Company witness Mr. Hari Singh discusses this assessment in his Direct Testimony.

Q. PLEASE DESCRIBE THE ITERATIVE NATURE OF THE RELIABILITY REVIEW AND HOW THE RESULTS OF THOSE REVIEWS INFORMED THE MODELING PROCESS.

A. If these reliability reviews identified that a particular reliability input requirement needed adjusting, then the adjustments would be made, the model would be rerun, and the output would be reviewed to see if the adjustment worked as intended. For example, if certain generating units were viewed as contributing more spinning reserves than they should or could, the modeling inputs that define a generating unit's contribution to spin would be adjusted and the model would be rerun. In addition, there are certain aspects of this type of modeling that are a function of the model output and therefore cannot be fully captured through the various upfront inputs into the model. For example, the required transmission upgrades that might be needed to reliably deliver the new

[16] This planned transmission eventually became the Colorado's Power Pathway project that the Company filed a CPCN for on March 2, 2021.

generation resources that were added to the system as a result of the optimization cannot be known until after the model is run. In this instance, the cost for any additional transmission requirements would be a post-modeling addition to the cost of the portfolio.

Q. HOW WERE THE OVERALL COSTS OF THE ERP AND CEP PORTFOLIOS DEVELOPED, REPRESENTED, AND COMPARED?

A. Each portfolio contains projections for the cost of all generators modeled for that particular portfolio, the costs associated with the operation and dispatch of those generators to reliably serve customer load, and projections of the cost for transmission needed to deliver the output of the generation fleet to load. Each of these cost categories are separately calculated and tracked within the EnCompass model. Portfolio costs are provided in two general manners: (1) on a present value or revenue requirement basis over a specified time period; and (2) as a percent change to total customer rates. The incremental costs of CEP portfolios are represented as incremental to the ERP portfolio costs, with the ERP portfolio costs serving as the reference case costs.

Q. WHAT LEVEL OF DSM AND CUSTOMER CHOICE PROGRAMS WAS REFLECTED IN THESE ERP AND CEP PORTFOLIOS?

A. The level of DSM included in the portfolios is consistent with the level of DSM resources that the Commission established in the DSM Strategic Issues filing, Proceeding No. 17A-0462EG. Growth beyond 2023, the final year of achievements established in that proceeding, reflects the Company's forecast of future achievements subject to approval as part of a future DSM Strategic Issues proceeding. The level of distributed energy resources represented in the portfolios is consistent with those levels approved as part of the RE Plan in Proceeding No. 19A-0396E.[17] Growth beyond those approved years was forecasted at approximately 105 MW per year. Company witness Mr. Jack W. Ihle discusses the interconnection of these filings in the ERP process further in his Direct Testimony.

Q. DOES THE COMPANY INTEND TO ACQUIRE ANY DSM RESOURCES OR CUSTOMER CHOICE SOLAR PROGRAMS, IN PHASE II OF THIS 2021 ERP?

A. No. As a practical matter, the amount of DSM and customer choice that Public Service will acquire over time are proposed and adjudicated in stand-alone proceedings separate from the ERP. Company witness Mr. Ihle discusses this segmentation of planning and acquisition, as well as the interaction with the ERP process, in more detail.

Q. IF THE COMPANY DOES NOT INTEND TO ACQUIRE DSM RESOURCES OR CUSTOMER CHOICE PROGRAMS THROUGH THE PHASE II PROCESS OF THIS 2021 ERP, THEN WHY IS IT INCLUDED IN THE ANALYSIS OF ALTERNATIVE PLANS?

A. DSM and customer choice programs are included because, in assessing the need for additional generation resources and the potential customer cost/savings impacts of those additions, it is important to account for all sources of future DSM achievements as well as all sources of future generation supply that are likely to

[17] Proceeding No. 19A-0396E specifically approved the annual capacity targets for the Solar*Rewards® and Solar*Rewards Community® programs.

be added through proceedings other than the 2021 ERP. In this regard, the ERP process represents an integrated view of how these various activities function together to serve the electric supply needs of our customers. For example, when assessing in an ERP whether additional generation capacity is needed to maintain an acceptable level of reliability, it is important to include all sources of generation supply (both existing and planned) as well as all sources of DSM within that assessment. In doing so, we better ensure that any additional generation capacity acquired through the ERP is in fact needed for purposes of maintaining acceptable overall system reliability.

Q. DID THE COMPANY PERFORM A BENCHMARKING ANALYSIS AS PART OF THIS ERP?

A. Yes. The topic of benchmarking analysis was discussed extensively in the ERP rulemaking proceeding (Proceeding No. 19R-0096E). Although no rules have been finalized through this process, the Company moved forward consistent with the general direction of the benchmarking proposal in the rulemaking proceeding. It is the Company's understanding that the objective of the benchmarking analysis is to identify, through a static economic screening process[18] using levelized cost representations, whether existing supply-side resources (with an emphasis on existing coal units) greater than 20 MW are cost-effective compared to alternatives available in the market. In the event such resources are identified

[18] A static screening analysis would typically be performed in a spreadsheet and would not require computer-based modeling which involves dynamic analysis of the larger Public Service system.

through benchmarking, further study of the costs and benefits of early retiring those resources could be warranted.

Q. WHAT WOULD THIS "FURTHER STUDY" WORK ENTAIL?

A. For Company-owned resources, further study work would entail computer modeling (i.e., dynamic analyses) that would consider a variety of factors associated with early retirement of a generating asset. These factors would include analysis of incremental depreciation expenses and estimated operational and capital savings from the unit, as well as the cost associated with replacement resource capacity and energy and costs associated with correcting any system reliability impacts triggered by the accelerated unit retirement. It is not clear to me, however, how these same costs and benefits would be represented in computer modeling of Power Purchase Agreements ("PPA") that are found to be not cost-effective compared to alternatives in the market. As we benchmark resources, the draft rules contemplate assessing all existing resources, both PPA and Company-owned generators.

Q. WITHOUT A STANDALONE BENCHMARKING EXERCISE, DOES THE ENCOMPASS MODELING OF ERP AND CEP PORTFOLIOS CAPTURE THESE VARIOUS FACTORS AS THEY RELATE TO EARLY RETIREMENT OF THE COMPANY'S REMAINING COAL UNITS?

A. Yes. The EnCompass modeling of ERP and CEP portfolios captures these costs and benefits that would be associated with accelerated retirement of each of the Company's remaining coal units. Frankly, I think for this 2021 ERP & CEP—setting aside the fact that the benchmarking approach has not been finalized by the Commission—the benchmarking analysis is not particularly instructive here for two reasons. First, the Company is proposing to take action on *all* of its remaining coal generators. Second, the EnCompass portfolio analyses are very detailed in capturing the impacts of early retirement from a system-wide perspective. In fact, the ERP and CEP portfolio analyses go one step further by evaluating a number of different combinations of actions that could be taken with the Pawnee and Comanche 3 units as discussed earlier in my testimony.

Q. WHAT DID THE BENCHMARKING ANALYSIS SHOW WITH REGARD TO NON-COAL FIRED EXISTING GENERATING RESOURCES?

A. In general, the analysis showed that the Company's owned resources over 20 MW appear cost-effective for customers as compared to the range of potential market alternatives (represented by generic resources) that may be available in the market. However, the benchmarking exercise does identify several existing wind and solar PPAs that do not appear cost-effective in comparison to potential market alternatives. This PPA outcome is most likely the result of changes in the market price for these technologies between the time they were acquired and today.

Q. WHAT WERE THE RESULTS OF THE ASSESSMENT OF POTENTIAL COST-EFFECTIVE EARLY RETIREMENTS OF UTILITY-OWNED RESOURCES WITH RETIREMENT DATES DURING THE PLANNING PERIOD?

A. The results of this analysis are presented in ERP Volume 2, Section 2.5. The evaluation supports the conclusion that early retirement and accelerated recovery of the existing gas-fired units results in added costs to customers under an assumption of $0/ton or the SCC. The added costs to customers increase when SCC is included because any loss of gas generation in general will lead to additional coal generation which has roughly twice the CO_2 emissions per unit of energy as gas-fired generation.

Q. HOW HAS THIS ASSESSMENT OF POTENTIAL COST-EFFECTIVE EARLY RETIREMENTS FACTORED INTO THE DEVELOPMENT OF ERP AND CEP PORTFOLIOS?

A. For the same reasons discussed above regarding the benchmarking analysis, and recognizing that the EnCompass modeling of ERP and CEP portfolios captures the costs and benefits associated with early retirement of the Company's remaining coal units, I do not view the results of this assessment as being particularly instructive for this 2021 ERP & CEP.

Q. WHAT IS YOUR OVERALL CONCLUSION OF THE BENCHMARKING AND POTENTIAL COST-EFFECTIVE EARLY RETIREMENT ANALYSES FOR THIS 2021 ERP?

A. This 2021 ERP & CEP includes the presentation of detailed analyses of multiple CEP portfolios that—through a combination of coal actions (including accelerated retirement of all the Company's remaining coal units) and the addition of high levels of zero-emission resources—meet or exceed the 80 percent CO2 reductions established in SB 19-236. When the ERP rulemaking started in Proceeding No. 19R-0096E several years ago, I understand why the benchmarking and early retirement analysis was a key topic. Given where we are now with this plan, however, I believe that these modeling analyses of CEP portfolios in and of themselves comply with the outcome ultimately contemplated in the rulemaking process.

VI. RESULTS OF ERP AND CEP PORTFOLIO ANALYSIS USING SOCIAL COST OF CARBON

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

A. In this section of my Direct Testimony, I will discuss the results of the ERP and CEP portfolio optimizations that were optimized using an assumption that the cost for each ton of carbon emitted is equal to the SCC as represented in the top half of Figure JFH-D-2 "ERP and CEP Portfolio Analysis" of my Direct Testimony.

Q. WHAT MIX OF GENERIC RESOURCES WERE SELECTED IN THE PORTFOLIO OPTIMIZATION OF THE COAL ACTIONS ILLUSTRATED IN FIGURE JFH–D-3 AND WHAT ARE THE PROJECTED 2030 EMISSION REDUCTIONS?

A. Figure JFH-D-3 below summarizes the results of the EnCompass modeling optimization, and details which generic resources were optimized for each of the of the eight paired Pawnee and Comanche 3 coal actions.[19]

[19] Each portfolio, i.e., SCC 1 through SCC 8, also includes early retirement of Craig 2 and Hayden 1 and 2, as noted earlier.

Figure JFH-D-3 SCC ERP and CEP Portfolio Generic Resource Additions and CO2 Reduction

	Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
	2030 CO2 % Reduction	**-69%**	**-88%**	**-85%**	**-86%**	**-88%**	**-81%**	**-84%**	**-85%**
	Resource Additions 2021-2030 (Nameplate MW)								
1	Wind	1,650	2,350	2,300	2,300	2,300	1,850	2,300	2,350
2	Utility-Scale Solar	1,150	1,550	1,550	1,500	1,550	1,250	1,550	1,550
3	Distributed Solar	1,158	1,158	1,158	1,158	1,158	1,158	1,158	1,158
4	Storage	400	450	400	450	400	400	400	400
5	Firm Dispatchable	1,276	2,352	1,960	1,568	1,764	1,505	1,276	1,233

The categories of resource additions include:

1. Wind: the nameplate MW of wind resources in each portfolio.

2. Utility Scale Solar: The nameplate amount of utility-scale solar generation resources in each portfolio.

3. Distributed Solar: The nameplate amount of distributed solar generation resources in each portfolio.

4. Storage: The nameplate amount of 4-hour duration utility-scale storage resources in each portfolio.

5. Firm Dispatchable: The nameplate amount of firm dispatchable resources added in each portfolio.[20]

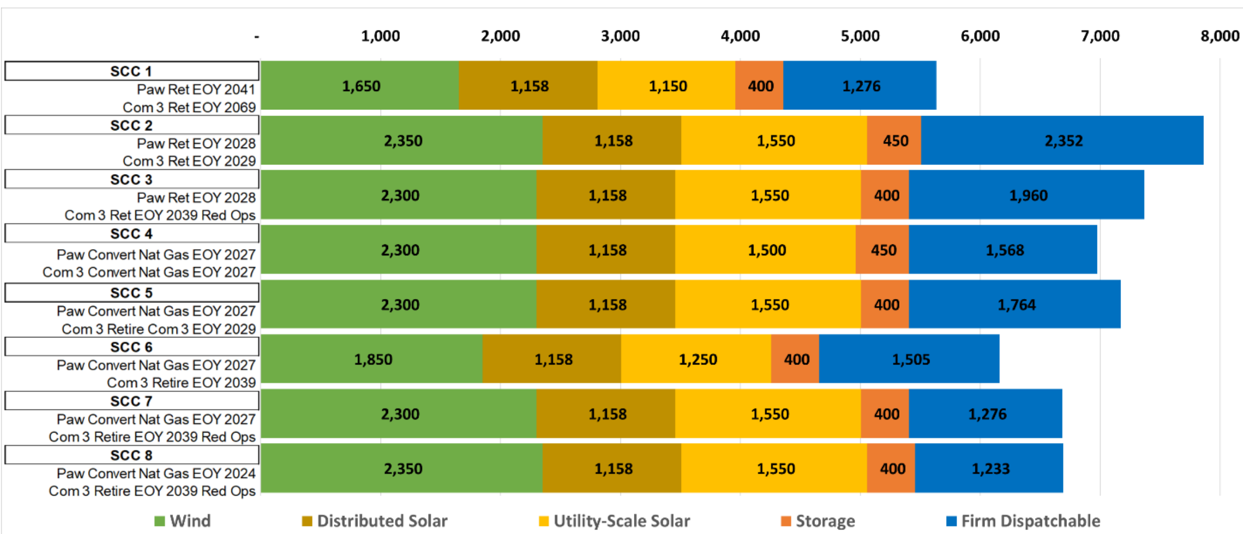
The ERP portfolio (SCC 1) includes 1,650 MW of wind and 1,150 MW of utility scale solar resources, which is less than the amount of wind and solar added in the CEP portfolios. The CEP portfolios (SCC 2 through SCC 8) add between 1,850-2,350 MW of nameplate wind and 1,250-1,500 MW of nameplate solar. From an emission reduction perspective, SCC 1 achieves a 69 percent

[20] For purposes of the Phase I modeling of ERP and CEP portfolios, generic gas-fired combustion turbine technologies were used to provide these firm dispatchable requirements.

emission reduction, while SCC 2 through SCC 8 achieve between 81-88 percent reductions by 2030.

As to firm and flexible dispatchable resources, SCC 1 includes a comparable amount of firm dispatchable resources at 1,276 MW as SCC 7 and SCC 8. The remaining SCC portfolios add between 1,500-2,350 MW of firm dispatchable resources. Figure JFH-D-4 below shows the resource additions of each ERP and CEP portfolio in graphical format.

Figure JFH-D-4 SCC ERP and CEP Portfolio
Nameplate MW Resource Additions 2021-2030



Q. DID THE COMPANY ESTIMATE THE POTENTIAL INFRASTRUCTURE INVESTMENT ASSOCIATED WITH THE INDICATIVE PORTFOLIOS IN FIGURES JFH-D-3 AND JFH-D-4?

A. Yes. Figure JFH-D-5 below shows the estimated generation and transmission infrastructure associated with the generic resource additions in Figure JFH-D-3 for years 2021-2030. The generation investment values represent the general level of dollars one could expect to be spent in constructing the generation resources in each portfolio.[21] The transmission investment values are reflective of the cost of the Colorado's Power Pathway project, which the Company filed a CPCN for on March 2, 2021.

Figure JFH-D-5 SCC ERP and CEP Portfolio Infrastructure Investment Potential

	Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
	Infrastructure Investment Potential ($M)								
1	Generation 2021-2030 ($M)	$ 4,282	$ 6,223	$ 5,814	$ 5,519	$ 5,650	$ 4,847	$ 5,378	$ 5,360
2	Transmission 2021-2030 ($M)	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667

Q. WHAT ARE THE PROJECTED COSTS OF THE INDICATIVE PORTFOLIOS IN FIGURE JFH-D-3?

A. Figure JFH-D-6 below includes several metrics to represent the costs and benefits of the clean energy actions in SCC 1 through SCC 8, including:

- The present value of the total annual carbon emissions of each portfolio multiplied by the SCC as established in SB 19-236;
- The PVRR over the entire 2021-2055 planning period (i.e., utility costs given they are representative of what is included in customer bills); and
- PVRR over different portions of the planning period to enable the Commission to see how costs/benefits are distributed over time.

Figure JFH-D-6 below contains different combinations of the present value of carbon emissions and PVRR utility costs.

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[21] Estimated construction costs for the different generic resource technologies can be found in Section 2.14 of ERP Volume 2.

Figure JFH-D-6: SCC ERP and CEP Portfolio Projected Costs

	Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
1	**PVRR Utility Cost 2021-2055 ($M)**	$ 38,814	$ 39,582	$ 39,429	$ 39,373	$ 39,450	$ 39,230	$ 39,306	$ 39,453
	PVRR Utility Cost Delta vs. SCC 1								
2	2021-2030 ($M)	$ -	$ 271	$ 192	$ 284	$ 265	$ 177	$ 206	$ 302
3	2021-2040 ($M)	$ -	$ 951	$ 621	$ 622	$ 786	$ 387	$ 479	$ 591
4	2021-2055 ($M)	$ -	$ 768	$ 616	$ 560	$ 637	$ 417	$ 492	$ 639
5	**NPV CO2 2021-2055 ($M)**	$ 8,625	$ 6,296	$ 6,719	$ 6,295	$ 6,234	$ 6,809	$ 6,646	$ 6,329
6	**PVRR Utility Cost + NPV CO2 2021-2055 ($M)**	$ 47,439	$ 45,877	$ 46,148	$ 45,669	$ 45,684	$ 46,040	$ 45,951	$ 45,782
	PVRR Utility Cost + NPV CO2 Delta vs. SCC 1								
7	2021-2030 ($M)	$ -	$ (124)	$ (77)	$ (271)	$ (226)	$ (153)	$ (158)	$ (370)
8	2021-2040 ($M)	$ -	$ (1,063)	$ (970)	$ (1,410)	$ (1,289)	$ (1,112)	$ (1,185)	$ (1,389)
9	2021-2055 ($M)	$ -	$ (1,561)	$ (1,290)	$ (1,770)	$ (1,755)	$ (1,399)	$ (1,487)	$ (1,657)

Q. HOW ARE THE INCREMENTAL COSTS/BENEFITS OF CEP PORTFOLIOS MEASURED IN FIGURE JFH-D-6?

A. The incremental costs and benefits of the additional clean energy actions in CEP portfolios are determined by comparing the PVRR Utility costs and NPV CO2 costs of each CEP portfolio to those of the ERP portfolio. In this instance, the ERP portfolio serves as a reference case for costing purposes. For example, when considering *both* the PVRR of utility costs and the NPV of CO2 costs, SCC2 shows $124 million in savings compared to SCC 1 over the 2021-2030 timeframe. When considering *only* the PVRR of utility costs, SCC2 shows $271 million of additional costs compared to SCC 1 over the 2021-2030 timeframe.

Q. DID THE COMPANY TRANSLATE THESE PROJECTED PVRR UTILITY COST IMPACTS INTO PROJECTIONS OF CUSTOMER RATE IMPACTS?

A. Yes. The bottom three rows of Figure JFH-D-7 below show projections of the average annual increase in retail customer rates for three different portions of the planning period: 2024-2030; 2024-2040; and 2024-2055. Given these are average values for a specific timeframe, in some years the annual rate increase is higher than the average indicated and in other years it is below the average. The Company believes, however, that an average value over the three time periods referenced provides a useful comparison across portfolios.

Q. WHY ARE AVERAGE ANNUAL RATE INCREASES MEASURED STARTING IN 2024 VERSUS PVRR COSTS, WHICH BEGIN THE FIRST YEAR OF THE PLANNING PERIOD (2021)?

A. The modeling results of ERP and CEP portfolios begin to include clean energy actions in year 2025. Accordingly, the Company felt it appropriate to begin measuring the change in customer rate impacts of such actions from year 2024 to 2025. In doing so, the Company differentiates between the rate impacts of clean energy actions in this ERP and the rate impacts of the Colorado Energy Plan in years 2021-2023—during which some of the Colorado Energy Plan resources and related facilities come online.

Figure JFH-D-7: SCC ERP and CEP Portfolio Projected Rate Impacts

	Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
	Average Annual Rate Impact								
1	2024-2030 (%)	2.1%	3.1%	2.8%	2.8%	2.9%	2.4%	2.6%	2.5%
2	2024-2040 (%)	1.5%	1.5%	1.6%	1.5%	1.5%	1.6%	1.5%	1.6%
3	2024-2055 (%)	1.7%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%

Figure JFH-D-7 shows customer impacts being at their highest levels between years 2024-2030 when the clean energy actions to achieve the 80 percent emission reduction target are being implemented. While the costs for clean energy actions to achieve the 80 percent clean energy target continue beyond 2030, the additional costs year over year tend to decrease, resulting in lower average annual rate impacts. This is evident by the lower average annual rate increases for years 2024-2040. For years 2040-2055, both ERP and CEP portfolios drive toward the carbon-free by 2050 target, adding more renewables and an assumption of higher fuel prices due to an ever-increasing blend of hydrogen into the fuel supply of the gas-fired fleet. These modeled actions to drive toward the carbon-free by 2050 target drive the average annual rate increases for 2021-2055 up to about 2 percent.

Q. HOW DOES ONE DETERMINE THE TOTAL OR CUMULATIVE PROJECTED RATE INCREASE OVER EACH OF THE DIFFERENT TIMEFRAMES IN FIGURE JFH-D-7?

A. When taken in isolation assuming all other rate making factors remain constant, total or cumulative rate impacts from the 2021 ERP & CEP can be estimated by multiplying the average annual rate increase by the number of years in each time frame. For example, the total or cumulative rate increase for the 2024-2030 timeframe for ERP SCC 1 would be about 12.6 percent. Assuming 2024 retail rates were 10₵s/kWh, 2030 rates would be 11.26₵/kWh. Similarly, the cumulative rate increase for the 2024-2055 timeframe for ERP SCC 1 would be about 52.7 percent. Assuming 2024 retail rates were 10₵s/kWh, 2055 rates would be 15.27₵/kWh. However, this is complicated by actual rate recovery mechanisms available via policy decisions as well as the fact that these decisions cannot be held in isolation or in vacuum when the time comes for actual cost recovery.

Q. GIVEN SB 19-236 ESTABLISHES THE CEPR AT 1.5 PERCENT OF RETAIL CUSTOMER BILLS, DO THE AVERAGE ANNUAL RATE INCREASES IN FIGURE JFH-D-7 THAT ARE GREATER THAN 1.5 PERCENT INDICATE THAT THE ADDITIONAL COSTS OF THESE PLANS WOULD EXCEED A 1.5 PERCENT CEPR?

A. No. The relevant data point for that issue is the delta or difference in average annual rate increases between SCC 1 versus SCCs 2 through 8 for years 2024-2030, which provides a general indication as to how the additional costs of the

CEP portfolios compare with a 1.5 percent CEPR. These deltas for SCC 2 through SCC 8 are between 0.3 percent and 0.7 percent more than SCC 1 (both less than a 1.5 percent); therefore, they provide a general indication that the additional costs of the CEP portfolios align with and are absorbed by the revenue stream associated with the CEPR. I describe this as a "general indication" because the average annual rate increases in Figure JFH-D-7 include all costs, including fuel and transmission, both of which are excluded from being recovered through the CEPR and recovered elsewhere (i.e., the Electric Commodity Adjustment and Transmission Cost Adjustment) under the statutory structure. A further assessment of the amount of additional costs that would qualify for CEPR funding would require a more detailed analysis that accounts for these costs elsewhere. A detailed analysis of CEPR costs is included in the Direct Testimony of Company witness Mr. Trowbridge.

Q. DID THE COMPANY DEVELOP A METRIC THAT WOULD ALLOW COMPARISON OF THE VARIOUS CARBON REDUCTIONS AND ASSOCIATED COSTS OF CEP PORTFOLIOS SCC 2 THROUGH SCC 8?

A. Yes. The Company developed a metric to quantify: (1) the additional 2021-2030 costs of CEP portfolio clean energy actions above those of the ERP reference case; and (2) the additional year 2030 carbon reductions achieved above those of the ERP reference case as a result of those additional actions. In short, the metric provides an indication as to how effective or efficient the incremental costs of clean energy actions compare with the incremental carbon reductions brought by those actions. Row 2 of Figure JFH-D-8 below contains this carbon reduction efficiency metric for each of the seven CEP portfolios. Lower $/ton values are better, providing a general indication of higher carbon reductions for each incremental dollar spent. It should be noted that this metric focuses on the front-end years of each CEP portfolio, years 2021-2030, and does not take into account incremental costs and associated carbon reductions between CEP and ERP portfolios for years 2031-2055.

Figure JFH-D-8: SCC ERP and CEP Portfolio CO2% Reduction Efficiency

	Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
1	**2030 CO2 % Reduction**	**-69%**	**-88%**	**-85%**	**-86%**	**-88%**	**-81%**	**-84%**	**-85%**
2	**CO2 Reduction Efficiency ($/ton)**	-	$ 46	$ 48	$ 34	$ 36	$ 36	$ 38	$ 28
3	**PVRR Utility Cost Delta vs. SCC 1** 2021-2030 ($M)	$ -	$ 271	$ 192	$ 284	$ 265	$ 177	$ 206	$ 302

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THE CO2 REDUCTION EFFICIENCY VALUES FOR CEP PORTFOLIOS IS CALCULATED?

A. Yes. The CO2 Reduction Efficiency values in row 2 of Figure JFH-D-8 are calculated by taking the PVRR Utility Cost Delta values from row 3 and dividing by the present value of each CEP portfolios' additional 2030 CO2 tonnage reductions above those of the ERP reference case. For example, the $46 value for SCC 2 is calculated by taking the $271 million PVRR Utility Costs Delta versus SCC 1 and dividing by 5.9 MST, which represents the present value of the additional CO2 reductions each year for years 2021-2030 compared to those of SCC 1.

Q. HAS THE COMPANY MEET THE REQUIREMENTS OF RULE 3604(K)?

A. Yes. Rule 3604(k) requires "a baseline case that describes the costs and benefits of the new utility resources required to meet the utility's needs…". Our SCC 1 portfolio, sometimes called the ERP or reference case, meets the requirements of that portion of the rule. The rule goes on to require alternate combinations of resources including "proportionately more" renewable energy resources, demand-side resources, energy storage systems, or Section 123 resources. The Company has modeled and presented numerous portfolios across two general sets of outcomes driven by the inclusion or exclusion of the SCC as a model input. These portfolios produce a varied set of renewable resource and energy storage outcomes. Specifically, wind varies from 1,000 MW up to 2,350 MW of new additions in the RAP. Utility-scale solar addition outcomes vary between 100 MW and 1,550 MW. Storage addition outcomes vary between 50 MW and 450 MW. I note that the Company has not modeled varying amounts of Section 123 resources in this Phase I filing; while we think, as Company witness Mr. Ihle explains in his Direct Testimony, that the Section 123 mechanism offers possibilities for technology advancement, the potential types of Section 123 resources are too diverse and un-defined to practicably model them for purposes of this Phase I. We anticipate receiving innovative Section 123 bids in Phase II and will evaluate them accordingly. Further, we interpret Rule 3604(k) and its "or" phrasing to allow a significant amount of flexibility in the resources that the Company provides "proportionately more" of, and again, we have provided a varied set of renewable and storage outcomes in this Phase I filing, as I have shown in my Direct Testimony. In addition, the Company also has provided eight different sensitivities for the purpose of testing the robustness of the alternate plans under various parameters.

VII. RESULTS OF ERP AND CEP PORTFOLIO ANALYSIS USING $0/TON CARBON COST

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

A. In this section of my Direct Testimony, I will discuss the results of the ERP and CEP portfolio optimizations. These optimizations were performed using an assumption that the cost for each ton of carbon emitted has a $0/ton cost.

Q. WHAT MIX OF GENERIC RESOURCES WERE SELECTED IN THE PORTFOLIO OPTIMIZATION OF THE COAL ACTIONS ILLUSTRATED IN TABLE JFH–D-2 AND WHAT ARE THE PROJECTED 2030 CARBON REDUCTIONS?

A. Figure JFH-D-9 below summarizes the results of the EnCompass modeling optimization, where generic resources were optimized for each of the of the eight paired Pawnee and Comanche 3 coal actions.[22]

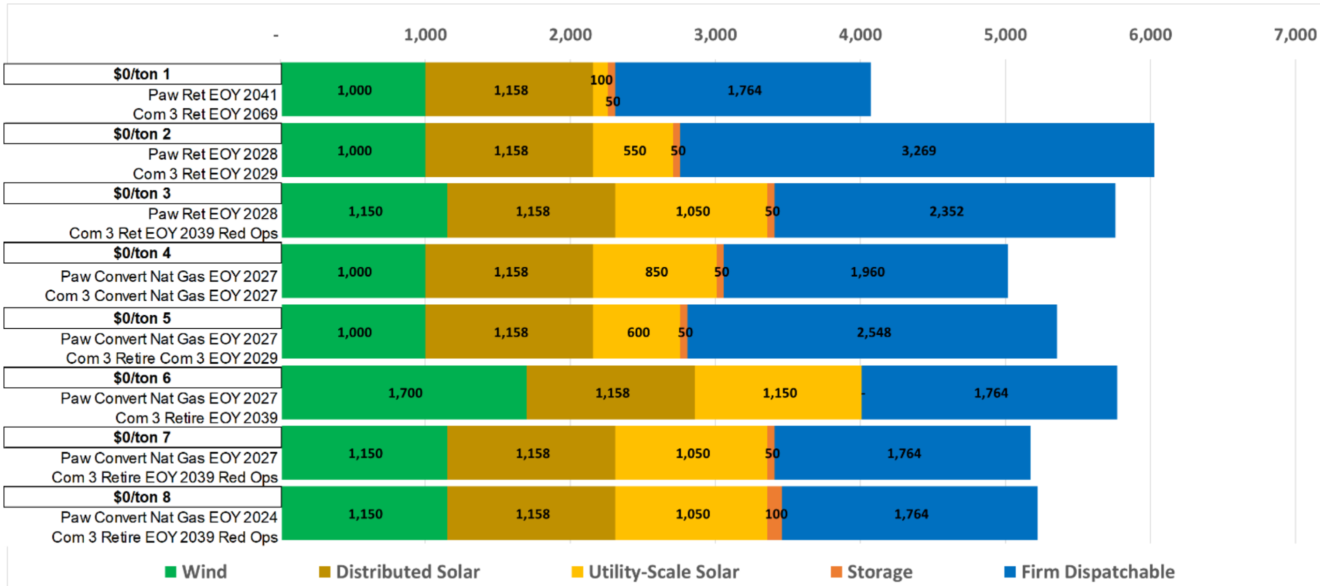
[22] Each portfolio $0/ton 1 through $0/ton 8 also include early retirement of Craig 2 and Hayden 1 and 2 as noted earlier.

Figure JFH-D-9: $0/ton ERP and CEP Portfolio
Generic Resource Additions and CO2 Reduction

	Portfolio	$0/ton 1	$0/ton 2	$0/ton 3	$0/ton 4	$0/ton 5	$0/ton 6	$0/ton 7	$0/ton 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
	2030 CO2 % Reduction	**-63%**	**-81%**	**-81%**	**-81%**	**-81%**	**-81%**	**-81%**	**-81%**
	Resource Additions 2021-2030 (Nameplate MW)								
1	Wind	1,000	1,000	1,150	1,000	1,000	1,700	1,150	1,150
2	Utility-Scale Solar	100	550	1,050	850	600	1,150	1,050	1,050
3	Distributed Solar	1,158	1,158	1,158	1,158	1,158	1,158	1,158	1,158
4	Storage	50	50	50	50	50	-	50	100
5	Firm Dispatchable	1,764	3,269	2,352	1,960	2,548	1,764	1,764	1,764

ERP portfolio $0/ton 1 includes 1,000 MW of wind and 100 MW of utility scale solar resources, while CEP portfolios $0/ton 2 through $0/ton 8 add between 1,000-1,700 MW of nameplate wind and 550-1,150 MW of nameplate solar. From a carbon reduction perspective, $0/ton 1 achieves a 63% CO2 reduction while $0/ton 2 through $0/ton 8 all achieve emission reductions of approximately 81 percent by 2030. From a firm and flexible dispatchable resource perspective, $0/ton 1, 6, 7, and 8 include 1,764 MW of firm dispatchable resources. The remaining $0/ton portfolios add between 1,960-3,269 MW of firm dispatchable resources. Figure JFH-D-10 below shows the resource additions of each ERP and CEP portfolio in graphical format.

Figure JFH-D-10: $0/ton ERP and CEP Portfolio Nameplate MW Resource Additions 2021-2030



Q. WHAT ARE THE ESTIMATED INFRASTRUCTURE INVESTMENTS ASSOCIATED WITH THE PORTFOLIOS IN FIGURE JFH-D-8?

A. Figure JFH-D-11 below shows the estimated generation and transmission infrastructure associated with the generic resource additions in Figure JFH-D-9 for years 2021-2030. The generation investment values represent the general level of dollars one could expect to be spent in constructing the generation resources in each portfolio.[23] The transmission investment values are reflective of the cost of the Colorado's Power Pathway Project, for which the Company filed a CPCN for on March 2, 2021.

[23] Estimated construction costs for the different generic resource technologies can be found in Section 2.14 of Volume 2.

Figure JFH-D-11: $0/ton ERP and CEP Portfolio Infrastructure Investment Potential

	Portfolio	$0/ton 1	$0/ton 2	$0/ton 3	$0/ton 4	$0/ton 5	$0/ton 6	$0/ton 7	$0/ton 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
	Infrastructure Investment Potential ($M)								
1	Generation 2021-2030 ($M)	$ 2,528	$ 4,226	$ 3,942	$ 3,301	$ 3,540	$ 4,186	$ 3,495	$ 3,558
2	Transmission 2021-2030 ($M)	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667

Q. WHAT ARE THE PROJECTED COSTS OF THE PORTFOLIOS IN FIGURE JFH-D-9?

A. Figure JFH-D-12 below includes several metrics to represent the costs and benefits of the clean energy actions in $0/ton 1 through $0/ton 8, including:

- The present value of the total annual carbon emissions of each portfolio multiplied by the SCC as established in SB 19-236;
- The PVRR over the entire 2021-2055 planning period (i.e., the utility costs given they are representative of what is reflected on customer bills); and
- PVRR over different portions of the planning period to enable Commission to see how cost/benefits are distributed over time.

Figure JFH-D-14 contains different combinations of present value of carbon emissions and PVRR utility costs.

Figure JFH-D-12: $0/ton ERP and CEP Portfolio Projected Costs

	Portfolio	$0/ton 1	$0/ton 2	$0/ton 3	$0/ton 4	$0/ton 5	$0/ton 6	$0/ton 7	$0/ton 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
1	**PVRR Utility Cost 2021-2055 ($M)**	$ 38,280	$ 38,875	$ 38,898	$ 38,692	$ 38,791	$ 38,913	$ 38,752	$ 38,898
	PVRR Utility Cost Delta vs. $0/ton 1								
2	2021-2030 ($M)	$ -	$ 221	$ 153	$ 189	$ 193	$ 163	$ 160	$ 248
3	2021-2040 ($M)	$ -	$ 808	$ 647	$ 497	$ 649	$ 605	$ 510	$ 613
4	2021-2055 ($M)	$ -	$ 595	$ 617	$ 412	$ 511	$ 633	$ 472	$ 617
5	**NPV CO2 2021-2055 ($M)**	$ 9,107	$ 7,051	$ 7,141	$ 6,924	$ 6,971	$ 7,027	$ 7,046	$ 6,758
6	**PVRR Utility Cost + NPV CO2 2021-2055 ($M)**	$ 47,387	$ 45,926	$ 46,039	$ 45,616	$ 45,762	$ 45,940	$ 45,798	$ 45,656
	PVRR Utility Cost + NPV CO2 Delta vs. $0/ton 1								
7	2021-2030 ($M)	$ -	$ (157)	$ (133)	$ (330)	$ (266)	$ (210)	$ (222)	$ (422)
8	2021-2040 ($M)	$ -	$ (974)	$ (1,044)	$ (1,421)	$ (1,212)	$ (1,182)	$ (1,277)	$ (1,462)
9	2021-2055 ($M)	$ -	$ (1,461)	$ (1,348)	$ (1,771)	$ (1,625)	$ (1,447)	$ (1,589)	$ (1,731)

Q. HOW ARE THE INCREMENTAL COSTS/BENEFITS OF CEP PORTFOLIOS MEASURED IN FIGURE JFH-D-12?

A. As described earlier in my Direct Testimony, the incremental costs and benefits of the additional clean energy actions in CEP portfolios are determined by comparing the PVRR Utility costs and NPV CO2 costs of each CEP portfolio to those of the ERP portfolio. This is the same exercise as that performed above for the SCC cases.

Q. WHAT ARE THE PROJECTED CUSTOMER RATE IMPACTS OF THESE $0/TON PORTFOLIOS?

A. The bottom three rows of Figure JFH-D-13 below show projections of the average annual increase in retail customer rates for three different portions of the planning period, 2024-2030, 2024-2040, and 2024-2055. Given these again represent average values for a specific timeframe, in some years the annual rate increase is higher than the average indicated and in other years it is below the average.

Figure JFH-D-13: $0/ton ERP and CEP Portfolio Projected Rate Impacts

	Portfolio	$0/ton 1	$0/ton 2	$0/ton 3	$0/ton 4	$0/ton 5	$0/ton 6	$0/ton 7	$0/ton 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
	Average Annual Rate Impact								
1	2024-2030 (%)	1.8%	2.7%	2.3%	2.2%	2.5%	2.4%	2.1%	2.1%
2	2024-2040 (%)	1.5%	1.4%	1.5%	1.4%	1.4%	1.6%	1.4%	1.5%
3	2024-2055 (%)	1.7%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%

Similar to the SCC ERP and CEP portfolios, Figure JFH-D-13 shows customer impacts at their highest levels between years 2024-2030 when the clean energy actions to achieve 80 percent clean energy target are being implemented. The costs for clean energy actions to achieve an 80 percent emission reduction continue beyond 2030, but generally at lesser amounts resulting in lower average annual rate impacts. For years 2040-2055, both ERP and CEP portfolios drive toward the carbon-free by 2050 target, adding more renewables and an assumption of higher fuel prices due to an ever-increasing blend of hydrogen into the fuel supply of the gas-fired fleet. These actions to drive toward the carbon-free by 2050 target result in average annual rate increases for 2021-2055 up to about 2 percent.

Q. HOW DOES ONE DETERMINE THE TOTAL OR CUMULATIVE PROJECTED RATE INCREASE OVER EACH OF THE DIFFERENT TIMEFRAMES IN FIGURE JFH-D-13?

A. Total or cumulative rate increases can be estimated by multiplying the average annual rate increase by the number of years in each time frame. For example, the total or cumulative rate increase for the 2024-2030 timeframe for ERP $0/ton 1 would be 10.8 percent, which is equal to 1.8 percent times 6 years. Assuming 2024 retail rates were 10₵s/kWh, 2030 rates would be 11.08₵/kWh. Similarly, the cumulative rate increase for the 2024-2055 timeframe for ERP $0/ton 1 would be 52.7 percent. Assuming 2024 retail rates were 10₵s/kWh, 2055 rates would be 15.27₵/kWh.

Q. HOW DO THE CARBON REDUCTION EFFICIENCY VALUES FOR $0/TON CEP PORTFOLIOS COMPARE WITH ONE ANOTHER?

A. Figure JFH-D-14 below shows how efficient the incremental costs of clean energy actions compare with the incremental carbon reductions achieved through those actions. Lower $/ton values are better, indicating higher carbon reductions for each incremental dollar spent.

Figure JFH-D-14: $0/ton ERP and CEP Portfolio CO2 Percent Reduction Efficiency

	Portfolio	$0/ton 1	$0/ton 2	$0/ton 3	$0/ton 4	$0/ton 5	$0/ton 6	$0/ton 7	$0/ton 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
1	**2030 CO2 % Reduction**	**-63%**	**-81%**	**-81%**	**-81%**	**-81%**	**-81%**	**-81%**	**-81%**
2	**CO2 Reduction Efficiency ($/ton)**	-	$ 39	$ 36	$ 24	$ 28	$ 29	$ 28	$ 23
3	**PVRR Utility Cost Delta vs. $0/ton 1** 2021-2030 ($M)	$ -	$ 221	$ 153	$ 189	$ 193	$ 163	$ 160	$ 248

VIII. PREFERRED PLAN

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

A. The purpose of this section of my Direct Testimony is to describe the Company's preferred plan based upon the Phase I generic modeling.

Q. WHAT CONCLUSIONS DOES THE COMPANY DRAW FROM THE ANALYSIS OF ERP AND CEP PORTFOLIOS?

A. The Company draws several conclusions from our analyses:

1. There are multiple paths by which we can reduce emissions by 80 percent or more by 2030 from 2005 levels, all while maintaining an acceptable level of system reliability and affordability for customers.

2. The previously announced early retirement of 273 MW of coal fired generation at Craig 2 and Hayden[24] are key aspects of any plan to achieve 80 percent by 2030.

3. Multiple paired actions can be taken at the two remaining coal-fired units, Pawnee and Comanche 3, to cost-effectively and reliably reduce the emission of carbon from these units.

4. A relatively balanced mix of new wind and solar resources (distributed and utility scale) will be needed in concert with accelerated coal retirements and paired actions at Pawnee and Comanche 3 to achieve or exceed the 80 percent clean energy target by 2030.

5. Additional firm dispatchable generation resources are needed that can do the following:

    a. Operate continuously for multiple days to ensure operators can dispatch the level of resources needed to continually serve customer load at all times, particularly during prolonged events in which we experience droughts in wind and solar generation output.

    b. Provide the fast and flexible generation resources needed to reliably manage around the increased level of variability we will see with increasing levels of wind and solar generation on our system.

[24] Public Service's ownership share.

6. Additional energy storage devices will be needed to provide a host of services that contribute to system reliability and reduced costs to customers through the provision of a variety of benefits including but not limited to: generation capacity credit, various operating reserves, energy arbitrage, and reduction in renewable generation curtailment.

Q. HAS THE COMPANY IDENTIFIED A PREFERRED CEP PORTFOLIO?

A. Yes. The Company's preferred plan is CEP SCC 7. Specifically, the coal actions of the preferred plan include:

1. Early retirement of Craig 2 in 2028 and Hayden 1 in 2028 and Hayden 2 in 2027;
2. Conversion of Pawnee to burn natural gas by 2028; and
3. Reducing generation from Comanche 3 to a level representative of a 33 percent annual capacity factor beginning in 2030 and early retiring the unit in 2040.

Coupled with these coal actions are indicative levels of generic wind, solar, storage, and firm and flexible dispatchable resources of approximately 2,300 MW, 1,600 MW, 400 MW, and 1,300 MW respectively. The actual level and composition of these and other resource technologies in the preferred plan will be determined through the Phase II competitive solicitation and bid evaluation process.

Q. WHAT FACTORS LED TO THE SELECTION OF CEP PORTFOLIO SCC 7 AS THE COMPANY'S PREFERRED PLAN?

A. In general, the primary factors considered: (1) the level of projected carbon reductions; (2) the additional costs for achieving those reductions; and (3) the community and workforce transition impacts of clean energy actions. While maintaining system reliability is of paramount importance to the Company, we believe that all CEP portfolios were built to a comparable and acceptable level of reliability and therefore we did not see reliability as a distinguishing characteristic between portfolios. Similarly, given that the indicative levels of wind and solar additions in each portfolio are in large part directly reflected in the projected carbon emission reductions of each portfolio, we did not see the levels of wind and solar adds as a distinguishing characteristic of portfolios, separate from projected carbon emission reductions.

Q. HOW DID THE LEVEL OF EMISSION REDUCTIONS INFORM SELECTION OF SCC 7?

A. As a threshold matter, given that CEP portfolios developed using the SCC show higher CO_2 emission reductions than portfolios developed using $0/ton for carbon, the Company focused on the results of the modeling optimizations that used the SCC in selecting a preferred portfolio.

As shown in Figure JFH-D-3, each of the seven CEP portfolios developed using SCC exceed 80 percent emission reductions, with SCC 2 and 5 showing the highest reductions at 88 percent, SCC 3, 4, 7, 8 showing between 84 to 86 percent, and SCC 6 showing the lowest reductions at 81 percent. From this perspective, SCC 7 provides a level of CO_2 emission reductions toward the middle of the range but well beyond that contemplated in the emission reduction target of SB 19-236.

Q. HOW DID CUSTOMER COSTS INFORM SELECTION OF SCC 7?

A. Customer costs were considered from two general perspectives: (1) average annual rate impacts: and (2) the efficiency of the dollars spent on clean energy actions at reducing CO_2 emissions.

As shown in Figure JFH-D-7, SCC 6, 7, 8 show the lowest 2024-2030 annual average rate impacts of 2.4 percent, 2.6 percent, and 2.5 percent, respectively. SCC 2, 3, 4, 5 show higher impacts of 3.1 percent, 2.8 percent, 2.8 percent, and 2.9 percent, respectively. From this perspective, SCC 7 shows increased costs to customers at the lower end of the range. The average annual rate impacts of all CEP portfolios for years 2024-2040 and years 2024-2055 converge to 1.6 percent; as a result, we did not see rate impacts for these longer timeframes as a distinguishing characteristic of portfolios from a decision-making perspective.

Q. HOW DID THE EFFICIENCY OF THE DOLLARS SPENT ON CLEAN ENERGY ACTIONS AT REDUCING CO2 EMISSIONS INFORM SELECTION OF SCC 7?

A. As shown in Figure JFH-D-8, SCC 8 shows a CO_2 reduction efficiency at $28/ton, due mostly to the way the metric favors CO_2 reductions that occur earlier versus those that occur later.[25] SCC 4, 5, 6, 7 show CO_2 reduction efficiencies between $34/ton and $38/ton and SCC 2 and 3 show $46/ton and $48/ton, respectively. As discussed earlier in my Direct Testimony, a lower $/ton value is better in that it provides a general indication of higher CO_2 reductions for each incremental dollar spent. From this perspective, SCC 7 shows a CO_2 reduction efficiency at the middle of the range.

Q. HOW DID COMMUNITY AND WORKFORCE TRANSITION CONSIDERATIONS INFORM SELECTION OF SCC 7?

A. The Company placed considerable importance on minimizing the impacts of the preferred plan coal actions on local communities and our workforce. SCC 7 minimizes these impacts by continuing to operate the Pawnee and Comanche 3 units to 2041 and 2039, respectively. The Pawnee plant located in Brush, Colorado will be converted to burn natural gas and operated to year 2041, which is the current retirement date of the unit. The Comanche 3 unit will continue to operate on coal at reduced levels from 2030-2039 and then will be retired. The Company's workforce transition and community assistance plans are discussed in more detail by Company witnesses Ms. Jackson, Ms. Holly L. Stanton, and Ms. Hollie J. Velasquez Horvath.

Q. WHAT OTHER CHARACTERISTICS OF SCC 7 ARE IMPORTANT TO CONSIDER?

A. In addition to the characteristics described above, we believe another potential benefit of SCC 7 is that it shows a requirement for considerably less new firm dispatchable generation resources as compared to other SCC portfolios. More specifically, the 1,276 MW level of new firm dispatchable resources in SCC 7 is

[25] As a result of using the present value of CO_2 reductions in this calculation, SCC 8 shows a higher reduction efficiency than other CEP portfolios even though some of those other portfolios result in overall higher carbon emission reductions by 2030.

between approximately 230 – 1,100 MW less than that included in all other SCC portfolios, with the exception of SCC 8.

Q. WHAT ARE SOME OF THE REASONS THE COMPANY LANDED ON SCC7 WITH COMANCHE 3 ON REDUCED OPERATIONS?

A. SCC 7 is a solid portfolio from an emission reduction standpoint, and it falls in the middle or towards the upper bounds of the ranges across the SCC portfolios. The preferred plan is projected to result in approximately an 85 percent emission reduction from 2005 levels by 2030—well above the 80 percent clean energy target of SB 19-236 and adding to the State of Colorado's overall emission reductions. There are three key reasons support why we landed on this approach for Comanche 3.

Q. WHAT IS THE FIRST REASON?

A. A good comparison point for SCC 7 is against SCC 6 because SCC 6 has the same action at Pawnee (conversion to natural gas at the end of 2027) while keeping Comanche 3 on through 2040 *without reduced operations.* The SCC 6 scenario achieves only 81 percent emission reductions and thus hi-lights the emission reduction value of the reduced Comanche 3 operations post-2029. Moreover, the SCC 6 portfolio results in (1) more firm dispatchable acquisitions (1,505 MW) as compared to SCC 7 (1,276 MW), (2) less wind (1,850 MW) than SCC 7 (2,300 MW), and (3) less utility-scale solar (1,250 MW) then SCC 7 (1,550 MW), too.

Q. WHAT IS THE SECOND REASON?

A. The "dual 2030 retirement scenario," *i.e.,* where both Pawnee and Comanche 3 are retired at end of year 2029, is SCC2. This scenario achieves an 88 percent emission reduction by 2030; however, it is important to go a layer deeper and look at the projected resource additions under this scenario as well as the added costs. The dual retirement scenario results in the acquisition of 2,350 MW of wind, 1,550 MW of solar, and 450 MW of storage, only 50 MW more wind and 50 MW more storage, and the same amount of solar, as compared to our SCC 7 preferred plan but at an added utility cost of $65 million, $472 million, and $276 million over the 2021-2030, 2021-2040, and 2021-2055 timeframes, respectively. Another key difference is in the addition of firm dispatchable resources, as the dual retirement scenario adds approximately 2,300 MW of these resources while the preferred plan adds only 1,300 MW. With approximately 1,400 MW of gas resources having expiring PPAs or retiring in the RAP, the net result is that the dual retirement scenario requires substantial incremental firm dispatchable resources, likely to be met in large part by gas additions, over and above that of our preferred plan. This goes to the option value discussion in the Direct Testimony of Ms. Jackson and why long-term thinking towards a carbon-free future, rather than a shorter-term approach, is imperative in this proceeding.

Q. WHAT IS THE THIRD REASON?

A. The third reason is that Comanche 3 continues to get a full accredited capacity credit under a reduced operations scenario, which is a benefit to the system and a benefit associated with the portfolio. Comanche 3 operation is limited but it is still a generator the Company can rely on to maintain system reliability if system conditions and circumstances warrant.

Q. BUILDING ON YOUR SECOND REASON ABOVE, WHY DOES THE COMPANY BELIEVE THAT REQUIRING LESS FIRM DISPATCHABLE RESOURCES IS A POTENTIAL BENEFIT TO SCC 7?

A. As a general matter, the current generation technology probably best suited to fulfill the role of firm dispatchable resources that can be started whenever needed and operated continuously for several days, are gas-fired combustion turbines or CTs. Certain parties to the Company's last ERP openly opposed the inclusion of two gas fired CTs that were included as part of the Colorado Energy Plan. As we understand, their opposition centered around that these CTs would burn natural gas, which is a fossil fuel. It is our expectation that these or other parties to this 2021 ERP will take a similar position and oppose the acquisition of new gas-fired CTs in Phase II. In this regard, the Company believes that the lower levels of firm dispatchable resources in SCC 7 would be viewed by these same parties as a plus.

Q. IS CURRENT COMBUSTION TURBINE (CT) TECHNOLOGY LIMITED TO BURNING ONLY NATURAL GAS?

A. No. We have contacted GE, Siemens, and MHI and confirmed that each supplier currently has CT units available that are capable of burning 30 percent hydrogen (by volume). Furthermore, each of these suppliers indicated that their goal is to have CT units capable of burning 100 percent hydrogen available to the market by 2030.

Q. DOES THE COMPANY INTEND TO REQUEST IN THE PHASE II BIDDING PROCESS A HYDROGEN BLEND CAPABILITY OPTION BE PROVIDED WITH BIDS PROPOSING THE CONSTRUCTION OF NEW CTS OR NEW RECIPROCATING ENGINES?

A. Yes. We are proposing to include language in the RFP document that encourages bids proposing a new CT facility or new reciprocating engine facility to provide an option for the facility to be capable of burning, at a minimum, 30 percent hydrogen (by volume), over the entire operating range of the unit (i.e., from minimum MW loading to maximum MW loading) while meeting emission permit requirements. This alternative fuel capability will allow the Company to transition toward our goal of a carbon-free future by 2050.

IX. ERP AND CEP PORTFOLIO SENSITIVITY ANALYSIS

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

A. The purpose of this section of my Direct Testimony is to discuss the various sensitivities performed by the Company on the portfolios developed for this Phase I proceeding.

Q. PLEASE DESCRIBE THE SENSITIVITY ANALYSES THAT WERE PERFORMED ON ERP AND CEP PORTFOLIOS.

A. In addition to the evaluation of ERP and CEP portfolios under base assumptions, portfolios were further analyzed through sensitivity analyses. These sensitivity analyses involve changing a single key input assumption and assessing how that change impacts a portfolio's carbon cost (i.e., repricing sensitivity) or the composition of resources added within the portfolio (i.e., reoptimized sensitivity). The primary purpose of sensitivity analyses is to test the robustness of the Company's selection of SCC 7 as our preferred plan under different futures. A detailed presentation of the sensitivity analyses performed is provided in Section 2.13 of Volume 2.

Q. WHAT IS THE DIFFERENCE BETWEEN A REPRICING SENSITIVITY AND A REOPTIMIZED SENSITIVITY?

A. The difference between the two types of analyses is whether the capacity expansion plan of the portfolio (i.e., the new resources that are added) is re-optimized. Some sensitivities, such as change in fuel prices, do not require that a new optimized expansion plan be developed in order to assess the impact of the changed assumption. These types of sensitivities are referred to as repricing sensitivities. In contrast, there are certain sensitivities, such as changes in load, where it is necessary to develop a new optimized expansion plan in order for a meaningful comparison of the sensitivity results with the base assumption results. In these sensitivity analyses, the model is given the flexibility to select a different mix of generic resources from those selected in the optimization performed using base assumptions. These types of sensitivities are referred to as reoptimized sensitivities.

Q. PLEASE DESCRIBE THE REPRICING SENSITIVITIES PERFORMED ON ERP AND CEP PORTFOLIOS.

A. Repricing sensitivities were performed on each ERP and CEP portfolio under the following assumptions:

High Gas Prices: Increase natural gas prices by using twice the annual year-over-year growth rate of base gas price forecast.

Low Gas Prices: Reduce natural gas prices by using one-half the annual year-over-year growth rate of base gas price forecast.

Q. PLEASE DESCRIBE THE REOPTIMIZED SENSITIVITIES PERFORMED ON ERP AND CEP PORTFOLIOS.

A. Reoptimized sensitivities were performed on each ERP and CEP portfolio under the following assumptions:

High Load: Widespread electrification consistent with the Greenhouse Gas Emission Reduction Roadmap developed by State of Colorado agencies and described in more detail in the Direct Testimony of Company witness Ms. Jackson.

Low Sales: Widespread adoption of distributed energy resources.

Expanded Market Access: Double the MW import and export capacity within the modeling.

Sunk Transmission Upgrade Cost: Assumes transmission network upgrade costs are sunk.

No New Gas Resources: Assumes no new gas-fired generation are added to the system.

Lower Hydrogen Costs: Reduce the hydrogen price assumption from \$20/MMBTU to \$10/MMBTU for the 2041-2055 period of the modeling. This is the period over which hydrogen blending occurs at an increasing rate of 10 percent each year, reaching 100 percent by 2050, for all gas-fired resources.

High and low load sensitivities were run for all ERP and CEP portfolios 1-8 for both SCC and \$0/ton. Expanded Market Access, Sunk Transmission Upgrade Cost, No New Gas Resources, and Lower Hydrogen Cost sensitivities were run for ERP portfolio 1 and CEP portfolios 2,4,7 for the assumption that CO2 emissions are priced at the SCC.

Q. WHAT WERE THE RESULTS OF THESE ANALYSES?

A. A detailed accounting of the numeric results of all sensitivity analyses are provided in ERP Volume 2, Section 2.13. To the extent that parties desire to drill down into the results of the analysis to better understand how a particular portfolio cost or benefit was affected in a specific sensitivity, that information is available in ERP Volume 2. However, to walk through in testimony the impacts of the eight sensitivity analyses on the various aspects of each plan would not be particularly instructive in my opinion. Accordingly, I instead provide higher-level observations as to how the sensitivity results serve to buttress the Company's selection of SCC 7 as the preferred plan.

Q. CAN YOU DESCRIBE THE GENERAL PROCESS BY WHICH YOU ASSESSED THE RESULTS OF THE SENSITIVITIES?

A. Yes. I assessed how the sensitivity analyses impacted each portfolio by applying a colored heat mapping concept to the analyses results. The colored heat mapping illustrates at a high level how the different portfolios compare or rank relative to one another for a particular portfolio characteristic (e.g., CO_2 reductions, PVRR utility costs, etc.) under a particular sensitivity. We applied a three-tiered color scale in which green represents the highest rank, yellow a middle rank, and red the lowest rank. One of the limitations of this heat mapping approach is that it does not provide information as to whether the difference between a green, yellow or red ranking for a particular plan characteristic is a material difference. For example, a $10 million difference in the 2021-2055 PVRRs between portfolios could result in one portfolio ranking green and another red. However, recognizing that the total 2021-2055 PVRR of portfolios is in the $40 billion range, a $10 million difference between plans in this instance is immaterial. Nevertheless, the materiality of different color rankings for each plan characteristic is readily available within the numeric values provided in the sensitivity results in ERP Volume 2.

Q. WHAT OBSERVATIONS AND CONCLUSIONS DO YOU DRAW FROM THE SENSITIVITY ANALYSIS RESULTS?

A That SCC 7 is a robust plan that can be expected to deliver on the CO2 emission reduction targets of SB 19-236 and do so in an affordable and reliable manner for customers. I base this conclusion on the following observations from the sensitivity results:

- From a carbon reduction perspective, SCC 7 shows no erosion of CO_2 reductions from the approximately 85 percent level projected under base assumptions. In fact, in four of the eight sensitivities, SCC 7 CO_2 reductions were shown to improve by increasing up to 89 percent.
- From a customer cost perspective, SCC 7 consistently ranks between the middle and the top relative to other portfolios across all eight sensitivities. This is evident by the green and yellow rankings of SCC 7 for PVRR Utility Costs Deltas versus the SCC 1 reference case, as well as in Average Annual Rate Impacts.
- From a CO_2 reduction efficiency perspective, SCC 7 ranks between the middle and the top relative to other portfolios in seven of the eight sensitivities. This is evident by the green and yellow rankings of SCC 7 for CO_2 Reduction Efficiency ($/ton).

Q. HOW DOES SCC 7 RANK FROM A SYSTEM RELIABILITY PERSPECTIVE?

A As discussed earlier in my testimony, we believe that all CEP portfolios were built to a comparable and acceptable level of reliability; therefore, we did not see reliability as a distinguishing characteristic between portfolios.

X. PROPOSED RESOURCE ACQUISITION METHOD AND KEY REQUIREMENTS

Q. WHAT PROCESS DOES THE COMPANY PROPOSE TO ACQUIRE ADDITIONAL RESOURCES THROUGH THIS 2021 ERP?

A. The Company is proposing to utilize an All-Source competitive solicitation or RFP process that is substantially similar to those approved and implemented in prior ERPs to acquire the resources necessary to meet the various needs and objectives of this 2021 ERP. The use of competitive procurement is the foundation of the successful ERP paradigm here in Colorado; moreover, SB 19-236 mandates the acquisition of resources through competitive bidding as part of this particular ERP. Volume 3 of the ERP contains the specifics of this competitive solicitation process including three distinct requests for proposal ("RFP") documents: (1) a Dispatchable Resources RFP; (2) a Renewable Resources RFP; and (3) a Company Ownership RFP. The RFPs allow a variety of supply-side generation technologies to be offered, as well as a variety of ownership and contracting structures (PPA, Company Self-Build, and Build-Own-Transfer). Company witness Mr. Scholl describes the proposed Phase II process in his Direct Testimony and additional details are provided in Section 2.16 of Volume 2.

Q. WHAT MODELING INPUTS AND ASSUMPTIONS WILL BE USED IN THE PHASE II COMPETITIVE SOLICITATION?

A. We will use the modeling inputs and assumptions set forth in our ERP, inclusive of any modifications ordered by the Commission through the Phase I decision.

These modeling inputs and assumptions are outlined in Section 2.14 of ERP Volume 2 and described in the Direct Testimony of Mr. Landrum. We will also follow the approach used in prior ERP cycles, where we make the final modeling inputs and assumptions available through a compliance filing after the Phase I decision but prior to the issuance of the RFPs that will commence the Phase II competitive solicitation process.

Q. ARE THERE ANY SPECIFIC RELIABILITY REQUIREMENTS FOR THE PHASE II COMPETITIVE SOLICITATION?

A. Yes. These are explained in more detail in the Direct Testimony of Mr. Welch. As an overview, the Company proposes the following requirements be met in the evaluation and selection of Phase II bids, specifically:

1. *A requirement that all proposed new or repowered/refurbished wind resources must be equipped with the appropriate cold-weather packages that will allow the turbines to reliably operate down to temperatures of negative 30 degrees Celsius or negative 22 degrees Fahrenheit.*

2. *A requirement that all bids offering new or existing dispatchable resources provide a description detailing the units cold-weather/winterization processes and packages*

3. *A requirement that all bids offering new or existing gas-fired resources provide an option for the storage of onsite fuel such as fuel-oil, of sufficient quantity to power the unit at maximum unit output for 3 consecutive days*

Q. WILL THE COMPANY BE REQUESTING BEST VALUE EMPLOYMENT METRICS FROM BIDDERS CONSISTENT WITH § 40-2-129, C.R.S.?

A. Yes. This is explained by Company witness Ms. Jackson, but we will be including and enforcing the BVEM requirements in our Phase II bid evaluation. While the Commission has not finalized BVEM rules, the Company worked extensively with labor interests to develop more detailed and robust BVEM for competitive solicitations. In keeping with what we worked on, the Company provides the guidelines below as part of the RFPs in Volume III:

Best Value Employment Metrics - Information Guidelines

(a) The availability of training programs, including training through apprenticeship programs registered with the United States Department of Labor, Office of Apprenticeship and Training. The utility or bidder shall provide, for example and as applicable, the following information for each craft the utility anticipates will work on the project:

(I) availability of training programs;
(II) the names of specific training programs available;
(III) the curriculum of the specific training programs;
(IV) the cost of worker training;
(V) the duration of the training programs;
(VI) the total number of hours of on-the-job training required;
(VII) the total number of classroom hours required;
(VIII) the licenses and certifications obtained, if any;
(IX) a copy of training program standards for each training program; and
(X) a statement whether the training programs are United States Department of Labor registered apprenticeship programs and are accredited to award college credits.

(b) The employment of Colorado workers as compared to importation of out-of-state workers. The utility or bidder shall provide, for example and as applicable, the following information for each craft the utility anticipates will work on the project:

(I) estimated number of workers by job classification;
(II) estimated length of time of service, including total man hours, by job classification;
(III) percentage of Colorado workers by job classification; and
(IV) percentage of project man hours earned by Colorado workers by job classification.

(c) Long-term career opportunities. The utility or bidder shall provide, for example and as applicable, the following information for each craft the utility anticipates will work on the project: job classifications, licenses, certifications and skills that will be applied and the long-term career opportunities for each job classification; and

(d) Industry-standard wages, health care, and pension benefits. The utility or bidder shall provide, for example and as applicable, the following information for each craft the utility anticipates will work on the project:

(I) range of wages by job classification;

(II) healthcare benefits by job classification;

(III) pension benefits by job classification;

(IV) prevailing wages and fringe benefits (healthcare benefits, pension benefits and other compensation) based on industry standards and the current Colorado labor agreements by job classification; and

(V) wages and fringe benefits (healthcare benefits, pension benefits and other compensation) by job classification.

XI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. Consistent with the discussion in my Direct Testimony, I support the recommendation of Company witness Ms. Jackson that the Commission approve Public Service's Phase I 2021 ERP & CEP.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

James F. Hill

Statement of Qualifications

As the Director of the Resource Planning and Bidding Group, I am responsible for overseeing the Company resource planning and competitive resource acquisition processes as well as the various technical analyses on the generation resource options that are available to Xcel Energy's operating companies for meeting future customer demand. I graduated from Colorado State University with a Bachelor of Science degree in Natural Resource Management and from the University of Colorado with a Bachelor of Science degree in Mechanical Engineering. I have been employed by Public Service Company of Colorado, New Century Services, Inc., and now Xcel Energy Services Inc. for over 30 years. I have testified before the Colorado Public Utilities Commission regarding electric resource planning issues in numerous dockets.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

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

AFFIDAVIT OF JAMES F. HILL
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO

I, James F. Hill, being duly sworn, state that the Direct Testimony and attachments were prepared by me or under my supervision, control, and direction; that the Direct Testimony and attachments are true and correct to the best of my information, knowledge and belief; and that I would give the same testimony orally and would present the same attachments if asked under oath.

Dated at Denver, Colorado, this 30th day of May, 2021.

James F. Hill
James F. Hill
Director, Resource Planning

Subscribed and sworn to before me this 30th day of May, 2021.

Amanda Clark
Notary Public

My Commission expires 3/25/2024

AMANDA CLARK
Notary Public
State of Colorado
Notary ID # 20164004880
My Commission Expires 03-25-2024