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

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

DIRECT TESTIMONY AND ATTACHMENTS OF ALEXANDER G. TROWBRIDGE

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

March 31, 2021

**BEFORE THE PUBLIC UTILITIES COMMISSION
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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
2016 ERP	Proceeding No. 16A-0396E, Public Service's 2019 Electric Resource Plan
2020-21 RE Plan, RE Plan, Plan, or Compliance Plan	Public Service's 2020-2021 Renewable Energy Compliance Plan
2021 ERP & CEP	2021 Electric Resource Plan and Clean Energy Plan
2021 Time Fence	Resources approved for procurement through plans prior to and including these groups of resources would be included in the time fence
CEP Portfolio	Clean Energy Plan Portfolio
CEPR	Clean Energy Plan Rider
ECA	Electric Commodity Adjustment
ERP	Electric Resource Plan
ERP Portfolio	Electric Resource Plan Portfolio
Retail DG	Retail Distributed Generation
PCCA	Purchase Capacity Cost Adjustment
Public Service or Company	Public Service Company of Colorado
RE	Renewable Energy
RES	Renewable Energy Standard
RES Plan	Renewable Energy Standard Plan
RESA	Renewable Energy Standard Adjustment
RJA	Retail Jurisdictional Allocator
SB19-236	Senate Bill 19-236
TCA	Transmission Cost Adjustment

Acronym/Defined Term	**Meaning**
WACC	Weighted Average Cost of Capital
Xcel Energy	Xcel Energy Inc.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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

DIRECT TESTIMONY AND ATTACHMENTS OF ALEXANDER G. TROWBRIDGE

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Alexander G. Trowbridge. My business address is 1800 Larimer Street, Denver, Colorado 80202.

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

A. I am testifying on behalf of Public Service Company of Colorado ("Public Service" or the "Company").

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. I am employed by Xcel Energy Services Inc. ("XES") as a Pricing Consultant of Pricing and 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 the "Company") and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis. I am responsible for development of new rate design proposals or modifications to existing rates to ensure effective price structures, increased options for customers, and compliance with regulatory requirements. A description of my qualifications, duties and responsibilities is included in my Statement of Qualifications 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 provide the framework for measuring the retail rate impact to customers as it relates to the Company's proposed 2021 Electric Resource Plan and Clean Energy Plan ("2021 ERP & CEP"). My testimony focuses on how incremental costs are modeled for the purpose of cost recovery through the Renewable Energy Standard Adjustment ("RESA") and the Clean Energy Plan Rider ("CEPR"). I discuss the delineation between the Clean Energy Plan Portfolio ("CEP Portfolio") and the Electric Resource Plan Portfolio ("ERP Portfolio"). I summarize existing modeling practices, provide a procedural history on certain locked elements of the Company's modeling assumptions, and introduce new key modeling mechanics that have resulted from the passage of Senate Bill 19-236 ("SB19-236"). I provide deferred cost projections and summarize the estimated retail rate impact.

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

A. Yes. I am sponsoring Attachments AGT-1 through AGT-3. Attachment AGT-1 presents the RESA deferred balance, projected RESA revenue, and RESA cost assumptions. Attachment AGT-2 presents the CEPR deferred balance, projected CEPR revenue, and CEPR cost assumptions. Attachment AGT-3 presents the

Company's calculation of average annual retail rate impacts when incorporating the RESA and CEPR recovery mechanisms.

II. COST RECOVERY OF THE 2021 ERP & CEP

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

A. The purpose of this section of my testimony is to provide an overview of cost recovery for the 2021 ERP & CEP, building on the discussion in the Direct Testimony of Ms. Brooke A. Trammell.

Q. PLEASE DESCRIBE KEY ELEMENTS OF THE COMPANY'S 2021 ERP & CEP AS IT RELATES TO CUSTOMER COST IMPACTS.

A. Public Service is developing a resource plan to achieve a statutory clean energy target of 80 percent reduction of carbon emissions by 2030 from 2005 levels. Therefore, for the first time and as explained by Company witnesses Ms. Alice K. Jackson and Mr. James F. Hill, the Company is conducting resource planning with a specific emission constraint. The preferred plan projects the addition of substantial amounts of renewable resources to meet the Company's resource needs. In addition, the Company is proposing certain actions with regard to the existing coal fleet including accelerating retirements, converting one coal facility to natural gas, and limiting operations at another coal facility.

Q. WHAT IS UNIQUE ABOUT THE COMPANY'S PROPOSAL IN THIS ERP?

A. A key component of the resource plan includes a requirement to distinguish between the resources necessary to meet customer demand (referred to hereafter as the traditional "ERP Portfolio") and the incremental clean energy resources and coal actions required to meet the clean energy target (referred to hereafter as the "CEP Portfolio").

Q. WHY IS THE CONCEPT OF PRESENTING AN ERP PORTFOLIO AND A CEP PORTFOLIO UNIQUE?

A. Traditionally, resource additions are planned incrementally in an ERP to ensure sufficient capacity to meet peak load requirements, respond to contingency events, and balance minute-to-minute load and generation. The CEP Portfolio represents the additional resource portfolio and actions that the Company must take in order to achieve its future carbon emissions reduction goals through 2030. Company witness Mr. Hill describes the development and details of the ERP portfolios and CEP portfolios in his Direct Testimony.

Q. ARE THERE COMPLEXITIES IN HOW THE COMPANY EVALUATES INCREMENTAL COSTS FOR THE PURPOSE OF DEFERRED RECOVERY?

A. Yes. While Commission rules and legislation guide how the Company should recover its cost of service attributable to the resource plan, the nature of the 2021 ERP & CEP creates several new layers of evaluation. These are necessary to incorporate historical elements of incremental cost recovery (such as those associated with the RESA), as well as new mechanisms afforded by SB19-236 that impact, expand, and augment existing cost recovery. These new mechanisms consist of the expanded use of the RESA[1] for incremental cost recovery of clean energy resources, e.g., energy storage and generation interconnection costs, as opposed to just eligible energy resources.[2] Similarly, SB 19-236 establishes a new recovery mechanism, the Clean Energy Plan Revenue Rider ("CEPR"), for

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[1] § 40-2-125.5 (3)(VIII), C.R.S.
[2] § 40-2-125.5 (2)(b), C.R.S.

additional costs attributable to meeting the carbon reduction goals of SB19-236 and measured as the difference between the ERP Portfolio and the CEP Portfolio.[3] Furthermore, SB19-236 recognizes some costs are also collectable through other existing recovery mechanisms, such as the Electric Commodity Adjustment ("ECA") for fuel costs, the Transmission Cost Adjustment ("TCA") for transmission costs, the Purchase Capacity Cost Adjustment ("PCCA"), and base rates for ERP capital, operating and related expenses.

Q. HOW WILL THE COST OF THE 2021 ERP & CEP BE RECOVERED FROM CUSTOMERS?

A. The incremental costs of the 2021 ERP & CEP will either be recovered through the RESA or the CEPR, while the remainder of costs are proposed to be collected through other existing mechanisms. Table AGT-D-1 summarizes key cost recovery assignments:

[3] § 40-2-125.5 (5)(III)(A)-(D), C.R.S.

Table AGT-D-1: Key Cost Recovery Assignments

Recovery Mechanism	Portfolio	Inclusion	Exclusion	Method of Measurement
RESA I	ERP	Incremental cost of renewables, RESA administrative costs	Modeled Avoided Costs	RES/No-RES
RESA II	CEP	Incremental Cost of Clean Energy Resources above RESA I	Modeled Avoided Costs	RES/No-RES
CEPR	CEP	Incremental CEP vs ERP (Capital, Fixed & Variable Costs, O&M, and Purchased Capacity)	Fuel, Transmission, RESA Recovery, ERP	ERP vs CEP, Less other riders
Base Rates	ERP & CEP	Capital, Fixed and Variable Costs and O&M	RESA, CEPR	Less other riders
PCCA	ERP & CEP	Purchased Capacity, Base Rate Capital Transition	CEPR	Less other riders
ECA	ERP & CEP	Variable Fuel, PPA Costs and Reactive Power	RESA	Less other riders
TCA	ERP & CEP	Transmission Costs	N/A	Less amounts recovered through base rates

Q. DESCRIBE THE HISTORY OF THE RETAIL RATE IMPACT ANALYSIS REQUIRED BY RULE 3661.

A. As required by both Rule 3661 and § 40-2-124(1)(g)(I), C.R.S., Public Service is required to perform a retail rate impact analysis.[4] Rule 3661 establishes that: (1) net retail rate impact of actions taken by the Company to comply with the Renewable Energy Standard ("RES") shall not exceed two percent of the total electric bill annually for each customer; and (2) the Company should develop two scenarios to estimate the retail rate impact. The first scenario, a Renewable Energy Standard Plan ("RES Plan"), should reflect the Company's plans and

[4] The concept of a retail rate impact cap on the RES was introduced in 2004 with Amendment 37, the voter-approved first version of the Colorado RES.

actions to acquire new eligible energy resources necessary to meet the RES. The second scenario, a "No-RES plan," should reflect a Company resource plan that replaces the new eligible energy resources in the RES plan with new non-renewable resources reasonably available. This is commonly referred to as RES/No-RES modeling.

Q. PLEASE EXPLAIN WHAT THE NO-RES COSTS REPRESENT IN THE RES/NO-RES MODELING.

A. Because Public Service is acquiring renewable generation, the resulting energy is displacing energy that would have been generated through conventional fossil fueled resources. As a result, a No-RES plan models the avoided energy savings from capacity that is already on the system, as well as avoided thermal capacity and energy costs that would have otherwise been procured if the renewable resources had not been procured.

Q. WITH THIS TRADITIONAL PARADIGM IN MIND, HOW DOES SB19-236 ADDRESS THE COSTS ASSOCIATED WITH A CLEAN ENERGY PLAN?

A. It addresses costs recovered from customers in several different ways as I will discuss in this testimony. However, first I would like to focus on the following two SB 19-236 provisions:

1. ***RESA Expansion.*** The Company may propose to use up to one-half of the funds collected annually under the RESA, as well as any accrued funds, to recover the incremental cost of Clean Energy Resources and their directly related interconnection facilities.

2. ***The CEPR.*** It establishes that the Company shall collect additional revenues on a percentage basis (up to one and one-half percent) for additional Clean Energy Plan activities through a Clean Energy Plan Revenue Rider ("CEPR").

Q. GIVEN THE FIRST ITEM ABOVE, ARE YOU SAYING SB19-236 MODIFIES WHAT COSTS CAN BE RECOVERED BY THE RESA?

A. Yes. SB19-236 allows use of up to one-half of the funds collected annually under the RESA, as well as any accrued funds, for the incremental cost of Clean Energy Resources and their directly related interconnection facilities. Two distinctions from the traditional RESA cost categories are important here. First, Clean Energy Resources are defined as electricity-generating technology that generates or stores electricity without emitting carbon dioxide into the atmosphere. This provision expands the RESA to cover the incremental cost of, among other items, CEP-related storage acquisitions. Second, interconnection facilities are specifically identified for recovery through the provisions of SB19-236. For example, this provision expands incremental cost recovery for interconnection facilities for owned units acquired as part of the CEP.

Q. WHAT PERCENTAGE OF CUSTOMER BILLS DOES THE RESA CURRENTLY COLLECT AND FOR WHAT TIME PERIOD?

A. Beginning in January 2009, the RESA was set to collect two percent of customer bills pursuant to Decision No. C08-0203.[5] However, consistent with the terms of

[5] Proceeding No. 08L-056E, Decision No. C08-0203 (mailed Feb. 28, 2008).

Decision No. C18-0762 issued in the Company's Accelerated Depreciation/RESA Reduction Proceeding (Proceeding No. 17A-0797E) and Decision No. C20-0700 issued in Proceeding No. 20AL-0191E, the Company has reduced the RESA to a collection level of one percent as of November 1, 2020.[6] In addition, Decision No. C20-0700 causes the RESA collections to terminate on December 31, 2022, unless the RESA is otherwise extended by the Commission.

Q. IS THE COMPANY PROPOSING TO EXTEND THE RESA COLLECTIONS PAST DECEMBER 31, 2022 AND IF SO, AT WHAT LEVEL?

A. Yes, as discussed more fully in the testimony of Ms. Brooke Trammell, the Company believes this plan supports the extension of RESA collections past December 31, 2022, maintaining the collections at one percent. The RESA mechanism works as a balancing account between revenues and expenses associated with eligible energy resource acquisitions. It allows the Company to incorporate additional renewable energy resources while maintaining a limited bill impact. As the Company continues its path to 100 percent carbon reductions by 2050, the RESA will continue to provide an important source of support to managing customer bill impacts.

Q. IS THE INCREMENTAL COST IDENTIFIED IN § 40-2-125.5(4)(A)(VIII), C.R.S. DIFFERENT THAN THE INCREMENTAL COSTS RECOVERED BY THE RESA?

A. The same avoided cost baseline can be used to determine the incremental costs of Clean Energy Resources and eligible energy resources. However, as discussed

[6] Proceeding No. 17A-0797E, Decision No. C18-0762, ordering ¶ 4 (mailed Sept. 10, 2018). At the same time the RESA was reduced to one percent a new rider, the Colorado Energy Plan Adjustment ("CEPA"), took effect at one percent of customers bills. The CEPA is projected to expire sometime in 2027.

above, "clean energy resources" are inclusive of, but defined more broadly than, eligible energy resources, as set forth in § 40-2-125.5(2)(b), C.R.S. Notably, the definition of "clean energy resources" includes energy storage. In addition, the cost of directly related interconnection facilities is included in the incremental cost determination under the terms of § 40-2-125.5(4)(a)(VIII), C.R.S.

Q. DOES THE COMMISSION'S REVIEW OF RES RULES CHANGE OR MODIFY THE FILING REQUIREMENT, RESA RECOVERY, OR OTHERWISE?

A. No. As of the drafting of this testimony, the Commission has engaged stakeholders in one workshop on potential future revisions to the RES rules. The Commission has advised interested stakeholders a new RES Notice of Proposed Rulemaking may issue in the June 2021 timeframe.

Q. GOING BACK TO YOUR LIST ABOVE, PLEASE EXPLAIN THE SECOND ITEM, THE CEPR.

A. As mentioned earlier, SB19-236 establishes that the Company shall collect additional revenues on a percentage basis (up to one and one-half percent) for additional CEP activities through the CEPR. The maximum retail rate impact under § 40-2-125.5(5), C.R.S. is calculated using the same total bill value as that is used for calculation of the maximum retail rate impact under § 40-2-124(1)(g), C.R.S. The only difference is that the CEP revenue rider value, i.e., the amount calculated based upon the total bill under § 40-2-125.5(5), C.R.S., is a one and one-half percent value. These calculations, however, are exclusive of one another and are instead calculated based upon the same total bill amount to derive the two revenue streams.

I provide and explain the Company's forecast of CEPR costs in Section IV of my Direct Testimony. As I explain further, this forecast is directional, and the actual costs will be determined after the completion of the Phase II process.

Q. HOW HAS THE COMPANY MEASURED THE COST OF ADDITIONAL CEP ACTIVITIES FOR THE PURPOSE OF RECOVERY THROUGH THE CEPR?

A. SB 19-236 requires the Company to distinguish between the resources necessary to meet customer demand versus a portfolio that addresses the future emission reduction goals. Further, it clarifies that CEP activities: (1) may create additional resource needs (not limited to renewable resources); (2) include the costs associated with the accelerated retirement of existing generating facilities; (3) include changes in system operations; and (4) any other necessary actions. The Company interprets this as recovering the additional costs between the ERP Portfolio and the CEP Portfolio, less amounts that are funded through the RESA and other rider mechanisms as set forth in the statute.

III. THE RESA AND ESTABLISHING A TIME FENCE

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

A. In this section of my Direct Testimony, I summarize the proposed implementation of the RESA if extended by the Commission.

Q. WHAT IS THE RESA?

A. As described above, the RESA is an up to 2 percent rider on each customer's total electric bill.[7] The revenues provided by RESA are recorded into a separate account and used to fund activities required for the Company to comply with the RES implemented pursuant to § 40-2-124, C.R.S. Section 40-20124(1)(g)(I), C.R.S. establishes the maximum retail rate impact for acquiring resources to meet the RES at "two percent of the total electric bill annually for each customer."

Q. UNDER TRADITIONAL RESA RECOVERY, PLEASE DESCRIBE WHAT COSTS ASSOCIATED WITH ELIGIBLE ENERGY RESOURCES ARE ACCOUNTED FOR THE IN ECA VERSUS THE RESA.

A. First, the Electric Commodity Adjustment ("ECA") accounts for the modeled avoided cost associated with RESA eligible energy resources. In order to determine modeled avoided cost associated with RESA eligible energy resources, the Company conducts RES/No-RES system modeling using software to measure the financial impacts of integrating a given portfolio of eligible energy resources on its system. More specifically, the Company models the system cost of including renewable resources (the "RES Scenario") against an alternative path (the "No-

[7] In addition to RESA rider revenues, Windsource subscription revenues and Hybrid REC Margin revenues also contribute to the RESA balance.

RES" Scenario) where the Company could have chosen a non-eligible energy resource.[8] RES/No-RES is the fundamental modeling concept that has been used since the inception of the RESA. For resources acquired to meet the RES after July 2, 2006, Rule 3661(h) explains what is included in the RES/No-RES model.

Second, Rule 3661(h)(III) establishes a "time fence" for examining the cost of renewable resources under § 40-2-124, C.R.S. By this rule, the costs of resources acquired prior to July 2, 2006 are not impacted by the passage of Amendment 37 (Colorado's RES) and the retail rate impact restrictions. Therefore, the cost of resources acquired prior to the time fence are fully recovered through the ECA and no allocation of their cost is recovered through the RESA.

Third, Section 123 Resources, defined as new energy technology or demonstration projects, including new clean energy or energy-efficient technologies under § 40-2-123(1)(a), C.R.S. and § 40-2-123(1)(c), C.R.S., are also recovered through the ECA without regard to RES/No-RES modeling. Figure AGT-D-1 below provides a view of how incremental costs are determined.

Figure AGT-D-1: Modeled Incremental Costs

Calculation of Incremental Costs:

RES Plan:		**NO-RES Plan:**		
Modeled System Cost of Utility Resources with Renewables	-	Redispatch of the Model with Traditional Resources Replacing Renewables Resources	=	(Modeled) Incremental Cost

[8] Section 40-2-124 specifically says: "The retail rate impact shall be determined net of new alternative sources of electricity supply from noneligible energy resources that are reasonably available at the time of the determination."

The incremental costs of eligible energy resources are calculated and charged against the RESA account. Incremental costs are typically based on the modeling approved in the Company's most recent Electric Resource Plan ("ERP"), subject to any modifications approved in the RES Plan filings. Avoided costs of the portfolio are charged to the ECA and represent costs that would have otherwise been incurred if renewable energy resources were not acquired. Figure AGT-D-2 below provides a simple view of how No-RES avoided costs are determined.

Figure AGT-D-2: Modeled Avoided Costs

Calculation of No-RES Avoided Costs:

Total Cost		**RESA**		**ECA**
Actual Cost Incurred	**-**	(Modeled) Incremental Cost	**=**	(Modeled) Avoided Cost

Q. PLEASE DESCRIBE TIME-FENCED RESOURCES.

A. The first category of resources included in both the RES and No-RES Plan scenarios are those resources behind what is called the "time fence." In accordance with Commission rules and decisions, resources acquired before July 2, 2006 are considered behind the Commission-created "time fence," i.e., the costs of these resources are considered "sunk" and are included in both the RES and No-RES Plan scenarios. As a result, these costs are not included in the calculation of the incremental costs of renewable energy.[9] These resources include Company-owned hydroelectric plants, a waste to energy facility, and certain wind

[9] *See* Commission Rule 4 CCR 723-3-3661(h)(III).

resources (Cedar Creek I, Foote Creek, Logan, Peetz, Spring Canyon, and Twin Buttes).

Q. PLEASE DESCRIBE LOCKED RESOURCES.

A. As mentioned above, RESA costs represent the modeled incremental costs of eligible energy resources when compared with a portfolio that otherwise excludes those resources. Certain costs were "locked down" by the Commission in Decision No. C16-1075 approving the three-case 2016 Comprehensive Settlement Agreement ("2016 Three Case Settlement"),[10] including the 2017-2019 Renewable Energy Compliance Plan. Page 75 of the 2016 Three Case Settlement provides that "[t]he Settling Parties agree that Eligible Energy Resources which were previously locked down are now reset under this RE Plan and allocated for cost recovery through the ECA/RESA based on the new model runs for the ten (10)-year planning period defined in Commission Rule 3661(f)."

Additionally, the cost of resources approved to be acquired through the 2016 ERP (Colorado Energy Plan) and 2020-21 RE Plan are also locked through 2021 in accordance with Decision C20-0289.[11]

Q. WHAT IS THE PURPOSE OF LOCKING THE INCREMENTAL COSTS?

A. At the time that eligible energy resources are acquired, the Company develops a specific net incremental cost to our system over the cost of a non-renewable resource and allocates RESA dollars based upon that projection. To the extent

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[10] The Proceeding Nos. 16AL-0048E (Public Service's Phase II Electric Rate Case), 16A-0055E (Public Service's Application for Approval of the Solar*Connect Program), and 16A-0139E (Public Service's Application for Approval of the 2017-2019 Renewable Energy Compliance Plan) were combined for purposes of settlement.

[11] Proceeding No. 19A-0369E (Public Service's 2020-2021 Renewable Energy Compliance Plan).

that the Company's recalculation of the incremental cost of the acquisition is greater (because gas prices turn out to be lower than projected), RESA funds may become inadequate to pay for those incremental costs. Once the annual net incremental costs of a project is "locked down," such costs would be fixed for the purpose of determining its impact on the RESA budget in future proceedings. Locking the incremental cost of eligible resources gives greater certainty to the availability of RESA funds to pay for resources committed to through the Company's various filings.

Q. PLEASE EXPLAIN HOW THE "LOCKED DOWN" COSTS ARE INCLUDED IN THE RESA DEFERRED FORECAST.

A. "Locked down" incremental costs means that the Commission has identified a specific $/MWh rate or total annual incremental cost for a specific resource for a specific period of time, and these incremental cost calculations are "locked down" and not revisited or re-determined in a RES compliance plan filing until the lock-down period expires.[12] The purpose of the lock-down rule is to provide customers and the utility with a level of certainty as to the accounting treatment of the incremental costs of resources already acquired that will be charged against the ECA and RESA accounts during the lock-down years, thereby facilitating planning for the acquisition of additional renewable resources. There are two eligible energy resources which are locked down for the life of the resource: SunE Alamosa and an early portion of the Company's Solar*Rewards® capacity.[13]

[12] *See* Commission Rule 4 CCR 723-3-3661(h)(V).
[13] Proceeding 08A-532E, Decision No. C09-1037, ¶ 43 (mailed Sept. 17, 2009).

Q. WHEN ARE THE "LOCKED DOWN" INCREMENTAL COSTS EXPECTED TO EXPIRE?

A. There are three groups of locked resources:

- ***Group 1 – Locked for Life.*** The two eligible energy resources locked down for the life of the resource.
- ***Group 2 – Locked Through 2026.*** The resources whose incremental costs have been locked through 2026.
- ***Group 3 – Locked Colorado Energy Plan/2020-2021 RE Plan Resources.*** This applies to the new resources added through the 2016 ERP as part of the approved Colorado Energy Plan Portfolio, as well as, new resources added through the 2020-2021 RE Plan. For Group 3 resources, the "locked down" period will expire on December 31, 2021.

Q. IN THIS PROCEEDING, IS THE COMPANY PROPOSING TO EXTEND THE LOCKED COST TREATMENT OF THESE RESOURCES BEYOND THEIR CURRENT EXPIRATION?

A. Yes. The Company is proposing to lock the modeled cost impacts from Group 2 and Group 3 for the life of those resources. This is discussed in more detail later in my testimony.

Q. DOES THE COMPANY CURRENTLY MODEL INCREMENTAL COSTS ON A RESOURCE-BY-RESOURCE BASIS OR A PORTFOLIO BASIS?

A. The Company models incremental costs on a portfolio basis. Modeling on a portfolio basis provides an integrated view that reflects whole-system level resource availability, volatility, and utilization. However, while the Company models its generation on a portfolio basis, it still attributes incremental costs to each non-on-site solar eligible energy resource for the purpose of recording the net RESA transfer from the ECA. In order to do this, the Company divides the attributed incremental cost by estimated potential production to develop a dollars-per-MWh incremental cost.

Q. IN THIS PROCEEDING, DOES THE COMPANY PROPOSE TO MODIFY THE PRACTICE FOR RECORDING INCREMENTAL COSTS?

A. Yes. The Company proposes to develop an average avoided $/MWh cost for "resource categories," such as wind, solar, and storage. The Company will aggregate purchase power agreement costs in the ECA and measure the incremental costs by subtracting actual generation multiplied by the avoided cost metric for that resource category. Incremental cost will then be transferred to the RESA based on this protocol, as opposed to on a $/MWh incremental cost as previously designed.

Q. WHY IS IT NECESSARY TO ESTABLISH A NEW RESA NET INCREMENTAL PROTOCOL FOR RECORDING INCREMENTAL AND AVOIDED COSTS IN THE FUTURE?

A. Due to the nature of the Company's future portfolio, namely the increasing levels of intermittent renewable resources, I anticipate greater curtailment volatility. This is simply due to a larger portion of the overall resources mix being subject to weather events and transmission or reliability constraints. While modeling provides an expectation of average annual curtailment volumes that will occur in the future, which helps us to assess a long-term incremental $/MWh cost, it does little to address protecting customers from bill volatility due to curtailment events. As wind projects continue to come on-line to meet planning requirements, the Company is concerned that there will likely be more significant volatility in the actual output of the wind facilities versus the modeled output. Because the RESA is currently the balancing rate mechanism, if there is more (or less) wind curtailment than projected, the RESA deferred balance should be impacted by the actual curtailment costs as opposed to only the average incremental cost of that generation. Since the Company often pays for wind curtailment on a per MWh basis, the full cost of any additional curtailment costs should go against the RESA deferred balance.

Q. ARE THERE OTHER REASONS TO ADOPT THIS PROPOSAL?

A. Yes. Modeling each resource individually is time-consuming and may not provide any additional discernable value that cannot otherwise be achieved by assigning an average avoided cost to “resource categories,” e.g., wind, solar, and storage. Additionally, I believe that this method provides a more common-sense approach to recording incremental and avoided costs.

Q. IS THERE A STATUTORY REQUIREMENT TO MODEL EACH INDIVIDUAL RESOURCE SEPARATELY?

A. No. The existing procedure was simply developed as a methodology for attributing incremental costs to individual resources. However, the process was developed at the inception of the RESA, when there was a much smaller number of renewable resources. By extension, the complexity of the approach was less burdensome.

Q. PLEASE EXPAND ON HOW ASSIGNING AN AVERAGE AVOIDED COST TO EACH "RESOURCE CATEGORY" WOULD SIMPLIFY THE RESA PROCESS.

A. First, less modeling would be required and, frankly, it would be more intuitive. This is important in my view given the RES/No-RES model has caused significant confusion for intervenors as its complexity has increased over time with changes on our system. A RES/No-RES model could be run for each of the resource categories to develop a distribution of the total avoided cost by resource type and then by MWh of anticipated actual generation.

Q. HOW DOES THE COMPANY PLAN TO ACCOUNT FOR COSTS AND RECOVERIES UNDER THE RESA AND THE RELATED PROVISIONS OF SB19-236?

A. The RESA has long been defined by the RES/No-RES process for eligible energy resources. When we combine the RESA provisions under SB19-236 with the existing RESA provisions under Rule 3661, it has the effect expanding the pool of resources and their costs that can be recovered by the portion of the RESA and RESA accrued funds available for CEP utilization. There are effectively two groups of RESA costs: (1) ERP-related RESA or RESA I, which is made up of traditional RESA costs for existing and new eligible resources that would be acquired in the base ERP portfolio using RES/No-RES modeling; and (2) CEP-related RESA or RESA II, which is the incremental CEP-related RESA costs using RES/No-RES. RESA II costs are first measured by taking the CEP portfolio and performing the RES/No-RES modeling for all unlocked and eligible resources, CEP storage, and CEP interconnection facilities, and then subtracting the incremental costs that are being evaluated by the RESA I group of costs. Under the RES/No-RES construct, incremental renewable costs are recorded to the RESA. No-RES cost, i.e., avoided costs, are recorded to the ECA and base rates. The following figures represent the basic formula for evaluating the RESA I and RESA II groups of costs:

Figure AGT-D-3: Basic Elements of RESA I

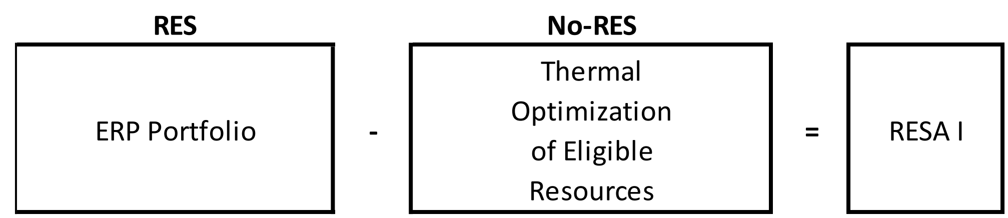
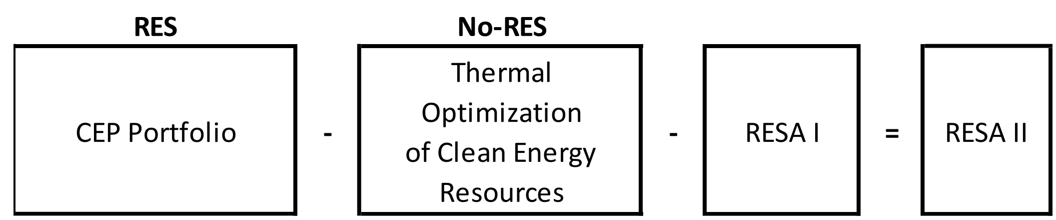


Figure AGT-D-4: Basic Elements of RESA II



Q. WHAT IS THE RESA DEFERRED BALANCE?

A. At a high level, the RESA deferred balance is composed of the difference between RESA Revenues and RESA Costs (including the modeled incremental costs associated with the addition of eligible energy resources). Interest is accrued on the deferred balance at the Company's after-tax weighted average cost of capital ("WACC").

The RESA pays for the modeled incremental costs of renewable energy resources above non-renewable energy resources. The modeled incremental costs may be more or less than the RESA revenues collected each year because it also depends on the non-incremental costs, or costs that would have otherwise been incurred are collected through the ECA. To the extent that the incremental costs are greater than the RESA revenues in any one year, Public Service carries forward, with interest, the unreimbursed costs. To the extent that the RESA revenues are greater than the incremental costs incurred in any one year, Public Service "banks" with interest the unexpended revenues for the purchase of eligible resources in future years.

Q. PLEASE DISCUSS THE COMPANY'S NEW TIME FENCE RECOMMENDATION THAT IS BEING MADE AS PART OF THIS PROCEEDING.

A. As mentioned earlier in testimony, the Company is proposing to lock the modeled cost impacts associated with Group 2 and Group 3 resources for the life of those resources. Resources approved for procurement through plans prior to and including these groups of resources would be included in the time fence ("2021 Time Fence"). Locking the incremental cost of eligible resources gives greater certainty to the availability of RESA funds to pay for resources committed to through the Company's various filings. Additionally, and more importantly, unlocking the portfolio for the Group 2 and Group 3 resources, would result in a significant deferral of costs to the RESA. I believe this deferral would be untenable for the Company and customers. To the extent that the existing resource portfolio is not locked down, the Company has a concern that it could serve as a barrier or deterrent to future renewable resources and, by extension, the ability to continue to progress towards the 2050 emission reduction goal of SB 19-236.

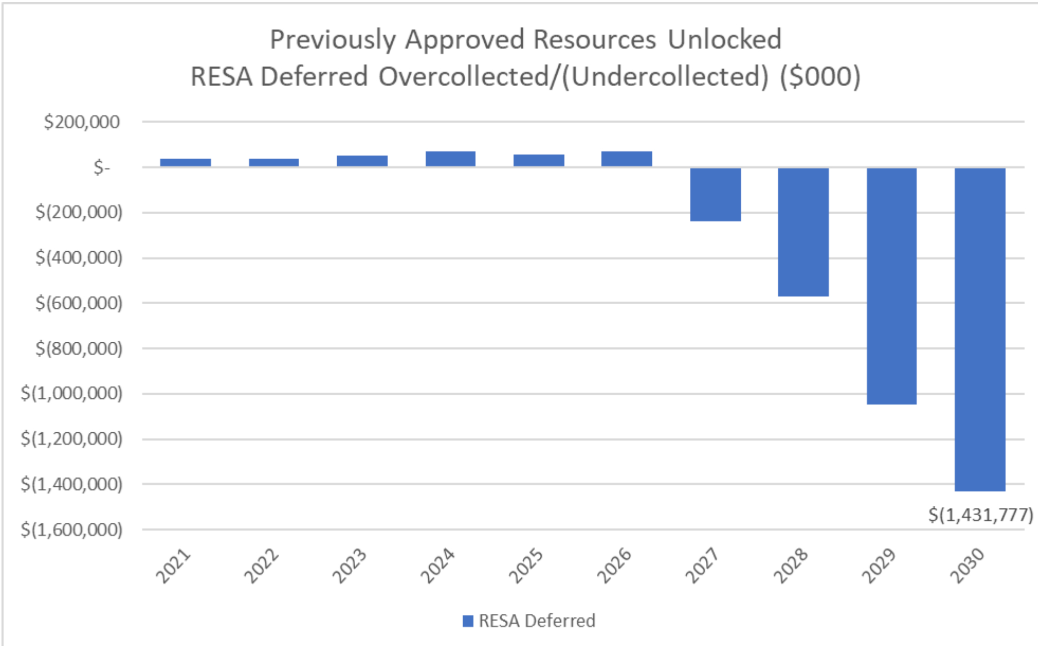
Q. ARE THERE OTHER CONCERNS THAT PLAY INTO THE COMPANY'S RECOMMENDATION TO ESTABLISH LOCKED INCREMENTAL COSTS?

A. Public Service remains concerned that any mandatory retrospective calculation of incremental costs could jeopardize the recovery of costs previously approved through Commission decisions in the event of a flattening or decrease in natural gas prices from prior projections, which would materially increase the incremental costs of these resources. In Decision No. C08-0559 addressing the Public Service 2008 RES Plan in Proceeding No. 07A-462E, the Commission agreed with the Company that Rule 3662(a)(XI), which requires a recalculation of the retail rate impact limit based upon actual compliance year values, is only necessary in those instances where the utility has not met the RES because of the limits placed on the utility by the retail rate impact limitations. Further, the Company believes that it should only perform a retrospective calculation of actual incremental costs in situations required by this Commission rule, i.e. situations where the Company has not met the percentage requirements of the RES. The Company is now and expects to remain in full compliance with all percentage requirements of the RES.

Q. PLEASE DESCRIBE THE IMPACT ON THE RESA DEFERRED BALANCE IF APPROVED RESOURCE COSTS ARE UNLOCKED IN 2022 AND 2027.

A. It is significant to note that preliminary modeling of the ERP portfolio assuming approved resource costs are unlocked in 2022 and 2027, as previously discussed, indicates that the RESA balance would become under-collected by approximately $1.4 billion in 2030. Figure AGT-D-5 presents an unlocked view of the RESA deferred balance 2021-2030:

Figure AGT-D-5: UNLOCKED RESA DEFERRED

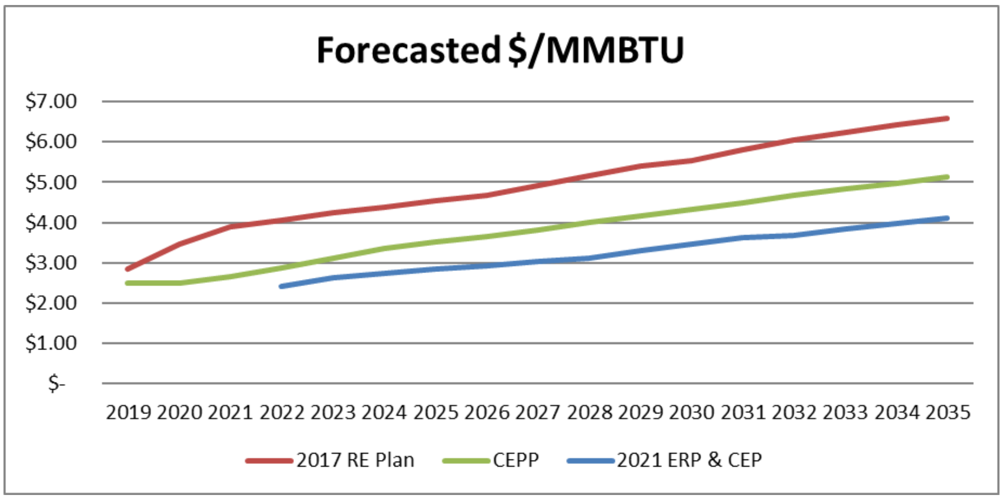


Q. WHY DO UNLOCKED RESOURCES RESULT IN SUCH A LARGE INCREMENTAL COST SHIFT STARTING IN 2027?

A. As mentioned, all resources procured prior to the 2016 ERP (Colorado Energy Plan) (Group 2 locked resources) were subject to a 10-year lock approved by the Commission. When those resources are unlocked and modeled against a No-RES portfolio using today's forecasted gas prices, we see a significant incremental cost increase from what was modeled under the locked assumptions. This is principally due to a change in the gas price forecast between vintages of modeling assumptions. Comparatively, current gas prices are lower than were anticipated and the futures curve is flatter than in previous forecast vintages. Specifically, when we look at the gas price assumption used for modeling 2016 ERP (Colorado Energy Plan), we see that gas prices in the current forecast are approximately 40%

lower in 2027 than were anticipated when modeling Group 2 resources. Figure AGT-D-6 presents gas forecast assumptions used in establishing incremental costs for the 2017 RE Plan,[14] the 2016 ERP (Colorado Energy Plan),[15] and the current gas forecast (2021 ERP & CEP):

Figure AGT-D-6: HISTORIC VS ACTUAL FORECASTED $/MMBTU



Q. WHAT DOES THE COMPANY BELIEVE IS THE PRINCIPAL ISSUE ASSOCIATED WITH LOCKING THE INCREMENTAL COSTS?

A. This is similar to the evaluation of prudent investments. That principle judges a utility action by reviewing the information reasonably available at the time that the investment decision had to be made. Similarly, the same principle should apply to the impact on the RESA from the acquisition of an eligible energy resources, *i.e.,* they should be calculated at the time that the acquisition decision is made and not continually revisited. In this way, if gas prices decrease from forecasted values,

[14] The natural gas prices used in the 2017 RE Plan were based on the forecast from the 1st quarter of 2016.
[15] The natural gas price forecast used in the Colorado Energy Preferred Plan ("CEPP") were based on the forecast from the second half of 2017.

the RESA funds are not impacted. Similarly, if natural gas prices are higher than projected, the RESA funds are not impacted.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED LOCKING INCREMENTAL COSTS FOR THE LIFE OF RESOURCES, AS PROPOSED IN THIS PROCEEDING?

A. Yes. Page 25 of Decision No. R09-0549 in Proceeding No. 08A-0532E states:

> 73… Ultimately, the Hearing Commissioner is persuaded by the arguments from Public Service and WRA… Locking down the net incremental cost of eligible resources…is legally permissible and it does allow the utility to plan for steady acquisitions of new eligible energy resources.
>
> 74…The General Assembly asks the Commission to balance the need for accuracy and transparency with the need to procure the maximum amount of eligible energy resources in an orderly and prudent manner. The Hearing Commissioner finds that the precedent set in Docket No. 07A-462E that established a time fence for resources acquired prior to 2008 has worked well and that there is no compelling evidence presented in this proceeding that argues against applying the lock down to the resources presented…[16]

This framework and rationale is as germane today as it has been over the last decade.

Q. HOW DOES THE COMPANY PROPOSE TO ACCOUNT FOR THIS "LOCKING DOWN" OF THE INCREMENTAL COST OF ENERGY RESOURCES?

A. Once the net incremental cost of these resources is "locked down" and approved by the Commission, such costs will be fixed for the purpose of determining their impact on the RESA budget in future RE plans and ERP proceedings.

[16] Decision No. R09-0549, at ¶¶ 73-74.

Q. WHAT IS THE CURRENTLY PROJECTED RESA DEFERRED BALANCE IF THE COMMISSION ADOPTS THE COMPANY'S TIME FENCE RECOMMENDATION?

A. Table AGT-D-2 below presents the projected balance through 2030, excluding the CEP-related RESA II costs. This projection assume that the RESA maintains a one percent level of collections through 2030. This table shows the under-collected balance of the RESA is projected at approximately $33 million by 2030. While this does result in a negative balance in the RESA in 2030, there are tools available (e.g., an increase in the RESA to its full statutory 2 percent (this would be post-CEPA), use of CEPR funds to cover the deficiency, or other approaches to be determined) that could be evaluated as we get closer in time and have more near-term RESA balance forecasts.

Table AGT-D-2: RESA Deferred Balance

RESA Deferred Balance ($000)						
Year	Total RESA Costs	Total RESA Revenue	Annual Excess/ (Deficiency)	Interest[1]	Annual Excess/ (Deficiency) w/ Interest)	RESA Rolling Balance (Deferred)
2020						$ 51,326
2021	$ 45,366	$ 29,221	$ (16,145)	$ 2,824	$ (13,321)	$ 38,005
2022	$ 31,653	$ 30,009	$ (1,644)	$ 2,428	$ 784	$ 38,789
2023	$ -	$ 31,516	$ 31,516	$ 3,562	$ 35,078	$ 73,866
2024	$ -	$ 32,455	$ 32,455	$ 5,883	$ 38,338	$ 112,204
2025	$ 48,861	$ 32,803	$ (16,058)	$ 6,803	$ (9,256)	$ 102,949
2026	$ 21,496	$ 33,155	$ 11,659	$ 7,103	$ 18,763	$ 121,711
2027	$ 32,101	$ 33,511	$ 1,410	$ 7,994	$ 9,404	$ 131,115
2028	$ 59,403	$ 34,172	$ (25,231)	$ 7,738	$ (17,493)	$ 113,622
2029	$ 108,797	$ 34,846	$ (73,951)	$ 5,005	$ (68,946)	$ 44,676
2030	$ 114,028	$ 35,533	$ (78,494)	$ 355	$ (78,140)	$ (33,464)

[1] Interest is calculated using the Company's most recently authorized after-tax weighted average cost of capital, 2021 estimated to be 6.53%.

Q. HAS THE COMPANY EVALUATED ANOTHER LEVEL OF RESA COLLECTIONS TO REFLECT A DIFFERENT APPROACH TO MANAGEMENT OF THE DEFERRED BALANCE?

A. Yes. The Company also evaluated the impact of dropping the RESA to 0.5% through 2030, presented in Table AGT-D-3. This table shows the under-collected balance of the RESA is projected at approximately $207 million by 2030. It also reduces the over-collected balance between 2023 through 2027.

Table AGT-D-3: RESA Deferred (REDUCED % COLLECTIONS)

RESA Deferred Balance ($000)						
Year	Total RESA Costs	Total RESA Revenue	Annual Excess/ (Deficiency)	Interest[1]	Annual Excess/ (Deficiency) w/ Interest)	RESA Rolling Balance (Deferred)
2020						$ 51,326
2021	$ 45,366	$ 29,221	$ (16,145)	$ 2,824	$ (13,321)	$ 38,005
2022	$ 31,653	$ 30,009	$ (1,644)	$ 2,428	$ 784	$ 38,789
2023	$ -	$ 15,758	$ 15,758	$ 3,047	$ 18,805	$ 57,594
2024	$ -	$ 16,227	$ 16,227	$ 4,291	$ 20,518	$ 78,112
2025	$ 48,861	$ 16,402	$ (32,460)	$ 4,041	$ (28,419)	$ 49,693
2026	$ 21,496	$ 16,578	$ (4,918)	$ 3,084	$ (1,834)	$ 47,860
2027	$ 32,101	$ 16,756	$ (15,346)	$ 2,624	$ (12,721)	$ 35,138
2028	$ 59,403	$ 17,086	$ (42,317)	$ 913	$ (41,404)	$ (6,266)
2029	$ 108,797	$ 17,423	$ (91,374)	$ (3,393)	$ (94,766)	$ (101,033)
2030	$ 114,028	$ 17,767	$ (96,261)	$ (9,740)	$ (106,001)	$ (207,034)

[1] Interest is calculated using the Company's most recently authorized after-tax weighted average cost of capital, 2021 estimated to be 6.53%.

Q. DOES THE COMPANY PLAN TO UPDATE ITS RESA BALANCE PROJECTIONS AFTER IT HAS SELECTED NEW ELIGIBLE ENERGY RESOURCES IN CONJUNCTION WITH THE CLEAN ENERGY PLAN PORTFOLIO?

A. Yes. After the Company has completed the bid process and identified the resources it has selected to present to the Commission through its 120-Day Report, the Company will present updated data tables and information. This will provide the parties and the Commission with the most updated RESA projections considering the resources included in the CEP Portfolio. The Company will formally file to extend the RESA, if appropriate, in a future RE plan proceeding as discussed in the testimony of Ms. Trammell.

IV. THE CLEAN ENERGY PLAN RIDER OR "CEPR"

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

A. In this section of my Direct Testimony, I explain the application of the CEPR in the Company's Phase I generic resource modeling.

Q. PLEASE EXPLAIN THE CEPR.

A. As mentioned earlier, SB 19-236 establishes that the Company shall collect additional revenues on a percentage basis (up to 1.5 percent) for additional Clean Energy Plan activities through the CEPR.

Q. HOW IS THE COMPANY DEFINING "CLEAN ENERGY PLAN ACTIVITIES" AS DESCRIBED IN SB 19-236?

A. The CEP Portfolio represents the resource portfolio and actions that the Company must take in order to meet the 2030 clean energy target. SB 19-236 requires the Company to distinguish between the resources necessary to meet customer demand versus a portfolio that addresses the future carbon reduction goals. Further, it clarifies that CEP activities: (1) may create additional resource needs (not limited to renewable resources); (2) include the costs associated with the accelerated retirement of existing generating facilities; (3) include changes in system operations; and (4) any other necessary actions. The Company interprets this as the additional costs between the ERP Portfolio and the CEP Portfolio, less amounts that are funded through the RESA and other rider mechanisms. Figure AGT-D-7 represent the basic formula for evaluating the CEPR group of costs:

Figure AGT-D-7: Basic Elements of CEPR

CEP Portfolio	-	ERP Portfolio	-	ECA[1] TCA RESA II[2]	=	CEPR

[1] ECA cost removed in measuring the CEPR relate to non-renewable ECA costs.
[2] RESA II costs can be collected through the RESA or the CEPR.

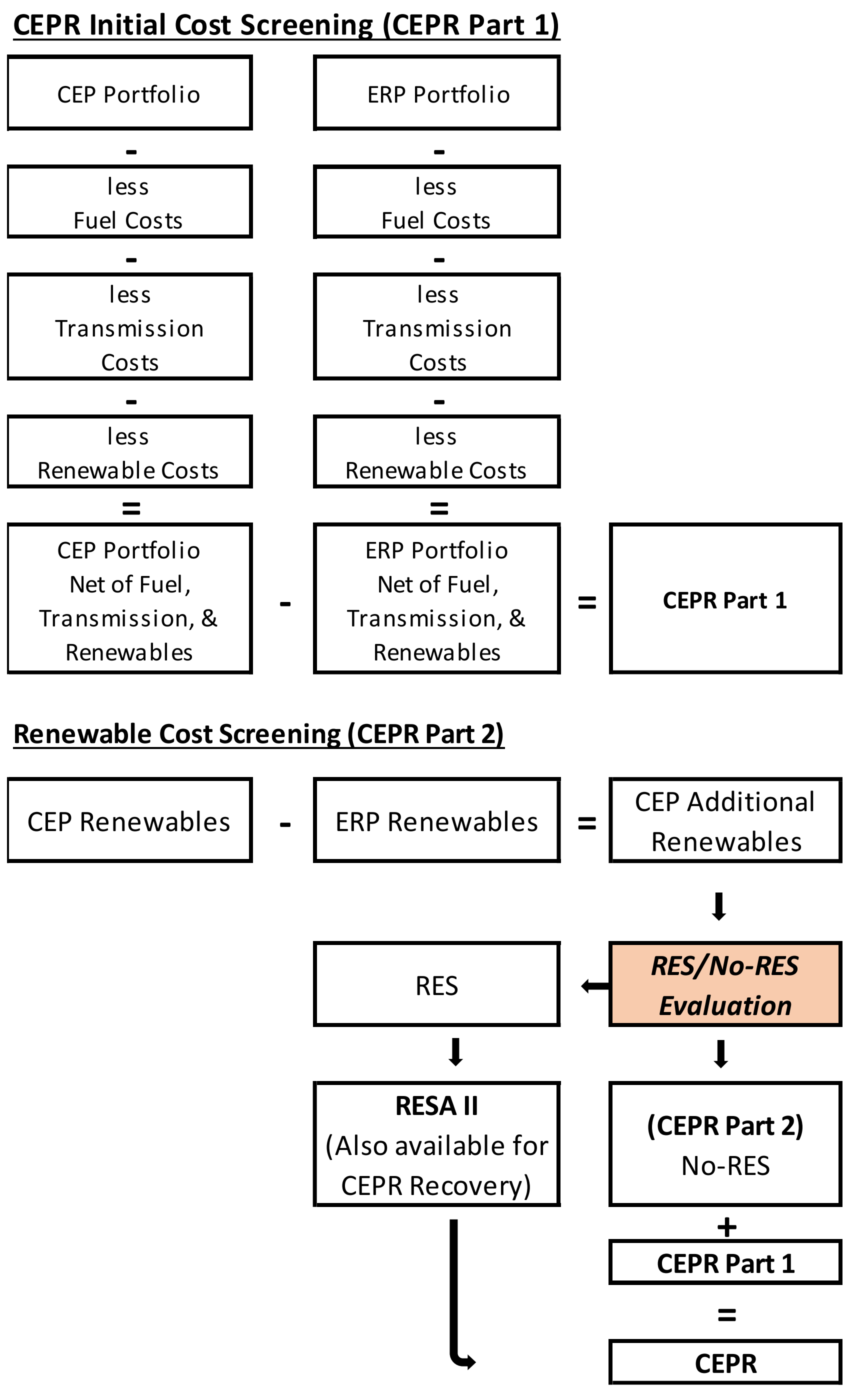
Q. HOW DOES THE COMPANY PLAN TO ACCOUNT FOR COSTS AND RECOVERIES UNDER THE CEPR?

A. The ERP Portfolio (similar to the No-RES portfolio for RESA) represents a modeling exercise to represent the path not taken versus the CEP portfolio that is designed to achieve the clean energy target of 80 percent reduction of carbon emissions by 2030 from 2005 levels. Beyond the additional costs that are recoverable through the ECA, TCA, and RESA, the CEPR will largely be responsible to recover additional capital related costs and fixed costs (including purchased capacity). Certain differences between the CEP Portfolio and the ERP Portfolio are discrete. For instance, the capital costs associated with Pawnee conversion to gas, and amortization of accelerated depreciation on a portion of the Pawnee facility are costs that can be specifically tracked and deferred as additional costs between the two portfolios. On the other hand, certain other elements of additional costs are simply a different level of costs, for instance in the category of fixed costs. Deferral elements of additional costs that are not discrete will be recorded based on the modeled additional costs resulting from the comparison of the two portfolios. I will refer to these as “Modeled CEPR” costs. To the extent that the Company cannot specifically assign costs to specific resources, the Modeled CEPR costs will receive an allocation to one of three categories: (1) capital related costs; (2) other base rate costs; or (3) purchased capacity. The first two categories are costs recovered through base rates. The third category, purchased capacity, is typically recovered through the PCCA.

Q. CAN YOU PROVIDE A MORE DETAILED DEPICTION OF THE MEASUREMENT COST IMPACTS TO THE CEPR?

A. Yes. Please see Figure AGT-D-8, which presents a breakdown of the mechanics that are used to evaluate additional CEP-related activity costs. The table breaks down the measurement of CEPR costs into two steps. Step 1 is an initial cost screening performed net of fuel costs, transmission costs, and the cost of renewables. Step 2 is a screening of additional renewable costs through the RES/No-RES process, where No-RES (avoided) costs are recovered by the CEPR, and RES (incremental) costs are recoverable through either the RESA or the CEPR.

Figure AGT-D-8: CEPR COST MECHANICS



Q. WHEN WILL CEPR COSTS BEGIN TO BE RECOVERED FROM CUSTOMERS AND HOW WILL THOSE FUNDS FLOW TO AND FROM THE CEPR?

A. CEPR costs will be determined with more certainty once we have actual resources in the 2021 ERP & CEP Phase II process. The Company will first apply CEPR collections toward the required return on appropriate capital investments, with the remainder of collections applied toward the applicable depreciation, amortization and other costs. Any amounts collected in excess of deferred costs will be tracked and used against future costs. In the first rate case following the implementation of the CEP any remaining positive balance shall be returned to customers or used to reduce customer rates, as provided for in SB19-236. In addition, and also consistent with SB19-236, any negative balance in the first rate case following the implementation of the of the Clean Energy Plan shall be incorporated into future rates. The CEPR functions as a tracker in this way for purposes of returning positive balances to customers or absorbing negative balances into rates after 2030.

Q. WHAT ARE THE CURRENTLY PROJECTED CEPR COSTS AND THE CEPR DEFERRED BALANCE?

A. The Company has assumed that the CEPR revenue will begin in 2024. Table AGT-D-4 below presents the projected revenue, costs and deferred balance through 2030. This table shows the over-collected balance of the CEPR is projected to reach approximately $57 million by 2030.

Table AGT-D-4: CEPR Deferred Balance

CEPR Deferred Balance ($000)						
Year	CEPR Costs	CEPR Revenue	Annual Excess/ (Deficiency)	Interest[1]	Annual Excess/ (Deficiency) w/ Interest)	CEPR Rolling Balance (Deferred)
2020						$ -
2021	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 4,412	$ 43,810	$ 39,398	$ 250	$ 39,648	$ 39,648
2025	$ -	$ 44,248	$ 44,248	$ 785	$ 45,033	$ 84,681
2026	$ 6,570	$ 44,691	$ 38,121	$ 1,318	$ 39,438	$ 124,119
2027	$ 8,008	$ 45,138	$ 37,130	$ 1,812	$ 38,942	$ 163,061
2028	$ 50,155	$ 46,041	$ (4,115)	$ 2,045	$ (2,070)	$ 160,991
2029	$ 57,905	$ 46,961	$ (10,943)	$ 1,975	$ (8,968)	$ 152,023
2030	$ 143,942	$ 47,901	$ (96,041)	$ 1,321	$ (94,720)	$ 57,303

[1] Interest is calculated using Federal Reserve seven-year treasury rate as quoted on report H.15 "Selected Interest Rates," 2021 is estimated to be 1.27%.

Q. DID THE COMPANY CONSIDER STEPPED CEPR IMPLEMENTATION TO TRY AND MATCH REVENUES WITH COSTS?

A. Yes. Table AGT-D-5 reflects a stepped approach where the CEPR starts at a 1 percent level, then steps up over time to the full 1.5 percent level.[17] Additionally, as mentioned earlier, CEP-related RESA II costs have been included for recovery through the CEPR. This table shows the over-collected balance of the CEPR is projected to reach approximately $1.2 million by 2030.

[17] CEPR Revenue Profile –

2024	2025	2026	2027	2028	2029	2030
1.0%	1.0%	1.0%	1.25%	1.5%	1.5%	1.5%

Table AGT-D-5: CEPR Deferred (STEPPED COLLECTION)

CEPR Deferred Balance ($000)						
Year	**CEPR Costs**	**CEPR Revenue**	**Annual Excess/ (Deficiency)**	**Interest[1]**	**Annual Excess/ (Deficiency) w/ Interest)**	**CEPR Rolling Balance (Deferred)**
2020						$ -
2021	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 4,424	$ 29,207	$ 24,783	$ 157	$ 24,940	$ 24,940
2025	$ 616	$ 29,499	$ 28,883	$ 500	$ 29,383	$ 54,323
2026	$ 6,570	$ 29,794	$ 23,224	$ 837	$ 24,061	$ 78,384
2027	$ 8,011	$ 37,615	$ 29,603	$ 1,183	$ 30,787	$ 109,171
2028	$ 50,153	$ 46,041	$ (4,113)	$ 1,360	$ (2,752)	$ 106,419
2029	$ 57,906	$ 46,961	$ (10,945)	$ 1,282	$ (9,663)	$ 96,756
2030	$144,017	$ 47,901	$ (96,117)	$ 618	$ (95,498)	$ 1,258

[1] Interest is calculated using Federal Reserve seven-year treasury rate as quoted on report H.15 "Selected Interest Rates," 2021 is estimated to be 1.27%.

It is important to bear in mind that in Phase I of the ERP, the Company submits a plan including an assessment of existing resources and the need for new resources, inputs and assumptions used in evaluating those resources, and its proposed method to acquire those resources. In the Phase II of the ERP, the Company initiates a competitive solicitation for new resources and evaluates actual bids consistent with the Commission directives from Phase I. Accordingly, we will be able to refine this projection once we have actual costs, but this provides an estimate based on current inputs and assumptions with our preferred plan at this time.

Q. WHY IS THE COMPANY PROPOSING TO BEGIN COLLECTIONS UNDER THE CEPR IN ADVANCE OF CEPR COSTS?

A. A majority of the CEPR costs occur in the later years of the RAP, up to and including calendar year 2030. In order to mitigate later rate increases for customers, it is important to commence CEPR collections as early as possible. Resource acquisitions are lumpy and the resource acquisitions and coal actions occur later in the RAP, i.e., there is less activity from a CEP activities standpoint in the early years of the RAP and then significantly more activity (e.g., accelerated retirements and resource acquisitions) in the later years as the Company gets closer to the 2030 clean energy target. The CEPR concludes with a final reconciliation in the first rate case after 2030 that incorporates the 2021 ERP & CEP revenue requirement into rates. Commencing collections early allows the CEPR to begin to build, and these funds can then help to offset the higher incremental costs that are incurred later in the RAP.

V. COST PROJECTIONS AND THE AVERAGE RATE FORECAST

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

A. In this section of my Direct Testimony, I provide details around the cost and rate projections associated with the preferred plan.

Q. WHAT ARE THE RESULTS OF THE COMPANY'S ANALYSIS OF THE RETAIL RATE IMPACT OF ITS ACQUISITION OF ELIGIBLE ENERGY RESOURCES?

A. The table below shows the rate impact for the preferred plan, which is explained in more detail in the testimony of Company witnesses Ms. Alice K. Jackson and Mr. James F. Hill. The first table presented in this section of my testimony shows the full cost of service prior to the application of RESA and CEPR revenues and collections, as well as, the average rate impacts year over year through the RAP. The table also provides averages from 2024-2030 and 2024-2040. We include a perspective covering 2024-2040 because the resources added in the RAP will generate far beyond 2030 and costs to customers continue beyond 2030, as well.

Table AGT-D-6: PSCo Average Rate impacts

PSCo Cost of Service ($000)	2024	2025	2026	2027	2028	2029	2030
Production Costs	$ 1,847,271	$ 1,929,142	$ 1,948,663	$ 2,026,245	$ 2,162,839	$ 2,306,438	$ 2,458,776
On-Going Transmission	$ 373,065	$ 359,594	$ 366,786	$ 374,122	$ 381,604	$ 389,236	$ 397,021
On-Going Distribution	$ 682,196	$ 700,177	$ 714,180	$ 728,464	$ 743,033	$ 757,894	$ 773,052
Colorado Power Pathway	$ 44,390	$ 49,020	$ 100,472	$ 86,222	$ 86,430	$ 78,488	$ 34,583
All Other Costs	$ 513,165	$ 504,109	$ 507,563	$ 514,439	$ 493,204	$ 509,596	$ 517,730
Forecasted Rev Req	$ 3,460,086	$ 3,542,042	$ 3,637,664	$ 3,729,493	$ 3,867,111	$ 4,041,652	$ 4,181,162
Total PSCo Sales	31,341,050	31,658,201	31,148,630	31,450,784	31,887,203	32,165,362	32,515,368
Average Rates $/kWh	$ 0.11040	$ 0.11188	$ 0.11678	$ 0.11858	$ 0.12127	$ 0.12565	$ 0.12859
Projected YoY Rate Growth		1.3%	4.4%	1.5%	2.3%	3.6%	2.3%
Projected Average Rate Growth 2024-2030							**2.6%**
Projected Average Rate Growth 2024-2040							**1.5%**

Q. WHAT ARE THE RESULTS OF THE COMPANY'S ANALYSIS OF THE RETAIL RATE IMPACTS WHEN INCORPORATING THE RESA AND THE CEPR?

A. The table below presents the retail portion of the revenue requirement allocated on the basis of kWh and incorporating the effect of RESA and CEPR revenues and cost deferrals. As you can see, the continuation of the RESA and early implementation of the CEPR—as proposed by the Company here—has the effect of decreasing the average annual rate impact from 2.6 percent to 1.4 percent for the period of 2024-2030, and has no significant change to the average annual rate impact for the period of 2024-2040.

Table AGT-D-7: Average Retail Rate impacts

Retail Cost of Service ($000)	2024	2025	2026	2027	2028	2029	2030
Retail Revenue Requirements	$3,235,406	$3,320,570	$3,509,207	$3,597,906	$3,731,173	$3,899,422	$4,034,237
RESA Revenue	$ 29,207	$ 29,499	$ 29,794	$ 30,092	$ 30,694	$ 31,308	$ 31,934
CEPR Revenue	$ 43,810	$ 44,248	$ 44,691	$ 45,138	$ 46,041	$ 46,961	$ 47,901
RESA Deferred Costs	$ -	$ (48,861)	$ (21,496)	$ (32,101)	$ (59,403)	$ (108,797)	$ (114,028)
CEPR Deferred Costs	$ (4,412)	$ -	$ (6,570)	$ (8,008)	$ (50,155)	$ (57,905)	$ (143,942)
Net Rev Req	$3,304,011	$3,345,456	$3,555,625	$3,633,027	$3,698,349	$3,810,990	$3,856,102
PSCo Retail Sales	29,305,922	29,678,719	30,048,674	30,341,116	30,766,295	31,033,433	31,372,783
Average Rates $/kWh	$ 0.11274	$ 0.11272	$ 0.11833	$ 0.11974	$ 0.12021	$ 0.12280	$ 0.12291
Projected YoY Rate Growth		0.0%	5.0%	1.2%	0.4%	2.2%	0.1%
Projected Average Rate Growth 2024-2030							**1.5%**
Projected Average Rate Growth 2024-2040							**1.4%**

Q. WHAT ASSUMPTIONS WERE MADE WITH REGARD TO THE RESA AND THE CEPR AFTER 2030?

A. At this point, while not a recommendation in this case, I have assumed the RESA and CEPR deferral mechanism are not used after 2030. Therefore, current average rate modeling assumes that customers are paying the full cost of service in their rates. While this was used for modeling purposes, we anticipate that the

RESA and CEPR, or another appropriate rate mechanism, may support on-going rate impact mitigation goals in the future. At a minimum, the CEPR would exist until the reconciliation detailed in Ms. Trammell's Direct Testimony in the first rate case following full implementation of the 2021 ERP & CEP resources.

Q. HOW HAVE THE RETAIL REVENUE REQUIREMENTS BEEN DETERMINED IN TABLE AGT-D-7?

A. I have applied the Retail Jurisdictional Allocator ("RJA") for kWh sales, which is essentially the percentage of retail sales divided by total sales, times the annual revenue requirement. Because the RESA and CEPR are retail mechanisms, it was necessary to present a retail revenue requirement when presenting the effect of the RESA and CEPR to average rates.

Q. IS THE RJA FOR KWH SALES THE ONLY ALLOCATOR THAT IS TYPICALLY USED TO ASSIGN COSTS BETWEEN RETAIL AND WHOLESALE CUSTOMERS?

A. No, and the Company has not performed a more detailed analysis for allocations between customer types. At this point, the Company believes that the average kWh metric is a good proxy of the potential impact to all customers.

VI. SUMMARY AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I recommend that the Commission approve the proposed "time fence" and associated locking of resources for Group 2 and Group 3 resources as described in my Direct Testimony. Consistent with this approach, I also recommend that the Commission approve the recording of incremental costs based upon a calculation of the average avoided cost determined by resource type as determined in this Phase I proceeding. As explained in the Direct Testimony of Ms. Trammell, we would use this lockdown approach as the RESA is evaluated in a future RE Plan proceeding.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Alexander G. Trowbridge

I have a Bachelor of Arts degree with a major in Accounting from Fort Lewis College in Durango, Colorado. Additionally, I am a Certified Public Accountant and maintain an active license in the State of Colorado.

I began my career in public accounting (1999–2005), working for the “Big 4” firms including Deloitte & Touche in Denver, Colorado and Los Angeles, California. Through my roles in Public Accounting, I have led the audit of various Fortune 500 Companies and participated in PCAOB Audit and SEC investigation activities. My public accounting industry experience includes Manufacturing, Real Estate, Construction, Insurance, Banking, and Investing.

Following six years in public accounting, I was employed by Sun Microsystems (2005–2009), first as a Technical Lead and Senior Financial Analyst responsible for technical research and financial modeling support related to acquisition and divesture activity, and later as the company’s SEC Reporting Manager; responsible to supervise the preparation of the SEC financial statements.

In May 2009, I was hired by Xcel Energy as a Principal Financial Consultant in the Transaction Enablement Accounting and Reporting group within the Utility Accounting organization. My principal duties were to evaluate all commercial contracts for lease, variable interest entity, derivative, and/or other technical accounting implications. I was responsible for developing accounting policies and documentation related to new transactions and/or the implementation of new or revised accounting standards. In

October 2012, I accepted a rotational position in the Controller's organization. In that role, I served as the interim Manager of Financial Reporting, and the Manager of Regulatory Accounting for Public Service Company of Colorado. Through those roles, I developed an in-depth knowledge of existing recovery mechanisms at Public Service Company and have successfully led teams through the issuance of Company financial statements including, SEC and FERC forms. In August 2014, began working for the Rates and Regulatory Affairs organization. In this role, I am responsible for development of new rate design proposals or modifications to existing rates to ensure effective price structures, increased options for customers, and compliance with regulatory requirements.

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	**)**

AFFIDAVIT OF ALEXANDER G. TROWBRIDGE
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO

I, Alexander G. Trowbridge, 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 Mar. 2021.

Alexander G. Trowbridge

Alexander G. Trowbridge
Pricing Consultant

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

Amanda Clark

Notary Public

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

My Commission expires 3/25/2024