**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 2022–2025 RENEWABLE ENERGY COMPLIANCE PLAN	**PROCEEDING NO. 21A-____EG**

DIRECT TESTIMONY AND ATTACHMENTS OF ALEXANDER G. TROWBRIDGE

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

December 20, 2021

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

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. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by Xcel Energy Services Inc. (“XES”) as Pricing Consultant. 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.

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 a Pricing Consultant employed by XES, 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 2022-2025 Renewable Energy Compliance Plan ("2022-25 RE Plan" or "Plan"). 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 ("SB 19-236"). My testimony also 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") and explain assumptions used in the Company's proposed 2021 Electric Resource Plan and Clean Energy Plan ("2021 ERP & CEP") in Proceeding No. 21A-0141E. I also discuss the Company's 2021 Time Fence recommendation included in this 2022-25 RE Plan. I further describe the modeling assumptions for the Encompass model runs that are used to calculate the incremental costs of certain Eligible Energy Resources, and present and provide the support for Tables 7-1 through 7-3 contained in the Company's RE Plan. Finally, I provide deferred cost projections and discuss the limitations of modeling assumptions currently available.

Q. DO YOU SPONSOR ANY SECTIONS OF ATTACHMENTS JWI-1 THROUGH JWI-3?

A. Yes. I sponsor Section 7 of Attachment JWI-1, which is Volume 1 of the Company's 2022-25 RE Plan and discusses the calculation of the Retail Rate Impact. I also sponsor portions of Sections 5 and 8 of Attachment JWI-1, as well as Tables 7-1 through 7-3 of Attachment JWI-2 (Volume 2 of the Plan).

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

A. Yes. I am sponsoring Attachments AGT-1 and AGT-2. Attachment AGT-1 presents the Company's proposed Solar*Rewards Community Service ("SRCS") Off-Site Net Metering Credit, and Attachment AGT-2 presents the Schedule SRCS Illustrative Tariff.

Q. WHAT RECOMMENDATIONS ARE YOU MAKING IN YOUR DIRECT TESTIMONY?

A. First, the RESA is set to expire on December 31, 2022. However, the costs associated with the requests embodied in this RE Plan support an extension of RESA collections beyond December 31, 2022.[1] I therefore recommend that the Colorado Public Utilities Commission ("Commission") authorize the Company to

[1] Proceeding No. 20AL-0191E, Decision No. C20-0700, at ¶ 21 states, "…Public Service is directed to support its request to continue the RESA with sufficient evidence of a revenue requirement commensurate with the proposed level of the surcharge."

maintain RESA collections at the one percent collection level. The Company anticipates needing revenue from the RESA at this level through the duration of this RE Plan and through 2030. Second, I recommend that the Commission accept the Company's 2021 Time Fence recommendation with regard to previously approved resources. Third, I recommend that the incremental and avoided costs associated with Distributed Generation ("DG") procurement approved in this Plan be established following Phase II of the Company's 2021 ERP & CEP, after the receipt of actual bids and updated pricing assumptions. Finally, I recommend that the Commission approve the Company's methodology for calculating the off-site net metering credit for its Off-Site Solar program.

II. RETAIL RATE IMPACT AND COST RECOVERY BACKGROUND

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 associated with the Company's RE offerings, the retail rate impact for the Company's customers associated with the Company's RE offerings, and explain the RES modeling Public Service undertakes pursuant to the Commission's Rules.

Q. PLEASE DESCRIBE THE RES MODELING REQUIRED UNDER RULE 3661.

A. Section 7 of the Company's 2022-25 RE Plan discusses the modeling requirements in more detail. However, at a high level, Rule 3661 requires that Public Service quantify the incremental cost of its Eligible Energy Resources and test whether its RE Plan meets the requirements of the retail rate impact set forth in Colorado statute and Rule 3661.

Q. WHERE IN THE COMPANY'S RE COMPLIANCE PLAN IS THE RETAIL RATE IMPACT PRESENTED?

A. Attachment JWI-1, Section 7, and Attachment JWI-2, Tables 7-1 through 7-3 of the 2022-25 RE Plan, contain a summary of the output information obtained from the model runs used to calculate the incremental cost differences between the "RES Plan" and the "No-RES Plan" scenarios. These cost analyses are used to determine the overall retail rate impact of acquiring these resources to meet or exceed Colorado's RES. The Company is using the same modeling assumptions as compared to what was filed for the RES and No RES portfolios with the 2021 ERP & CEP Plan in Proceeding No. 21A-0141E.

Q. ARE THE MODELING ASSUMPTIONS FROM THE 2021 ERP & CEP PLAN SUBJECT TO CHANGE?

A. It is difficult to know the extent of change that will result when the Company updates its modeling assumptions through Phase II of the 2021 ERP & CEP (i.e., the competitive acquisition and bid evaluation process), because: (1) resource costs are based on generic modeling assumptions[2]; (2) the mix and timing of actual resources, including the mix of Company-owned resources, is still pending a Commission final decision in Proceeding No. 21A-0141E; (3) forecasted commodity price (and other pricing assumption) updates may be material given recent inflationary cost trends; (4) federal tax proposals and incentives could materially change the results of Independent Power Producer ("IPP") bids and Company ownership costs; and (5) the Company's RESA revenue assumptions are subject to change with the overall level of revenue collected from customers.[3]

Q. GIVEN THAT THE COMPANY'S FORECAST IS ANTICIPATED TO CHANGE THROUGH UPDATED MODELING AND ASSUMPTIONS IN PHASE II OF THE COMPANY'S 2021 ERP & CEP, HOW IS THE COMPANY EVALUATING INCREMENTAL COSTS IN THIS PROCEEDING?

A. The Company recommends maintaining the incremental cost modeling established in Proceeding No. 19A-0369E (Public Service's 2020-21 RE Plan) for

[2] Key inputs and assumptions include, for example, ongoing costs of the system, generic resources, capital cost recovery mechanisms, workforce and community transition, transmission-related costs, cost of carbon, and system reliability costs.

[3] RESA revenue can be driven by changes in variables such as commodity prices, changes sales volumes (including contributions due to the general economic environment or pace of fuel switching), changes in participation in the Company's Windsource® program, and realized Hybrid Renewable Energy Credit ("REC") revenues.

any new DG resources until the Company has completed Phase II of its 2021 ERP & CEP. At that time, and through presentation of the Company's 120-Day Report, the Company will adopt the updated incremental and avoided cost modeling consistent with those results.

Q. IS THE COMPANY PRESENTING THE SAME TIME PERIODS AS WERE PRESENTED IN THE 2021 ERP & CEP?

A. Yes. Under its 2022-25 RE Plan, the Company is presenting the 10-year period from 2021-2030, consistent with Rule 3661(f).

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

A. In Proceeding No. 21A-0141E, 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, consistent with Colorado law. Therefore, for the first time, the Company is conducting resource planning with a specific emission constraint. The Company's preferred plan in Proceeding No. 21A-0141E 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. The Company does not anticipate a final Commission decision on a CEP portfolio until early 2023.

Q. WHAT IS UNIQUE ABOUT THE COMPANY'S PROPOSAL IN THE 2021 ERP & CEP?

A. A key component of the resource plan in Proceeding No. 21A-0141E 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 have been 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 an additional resource portfolio and actions that the Company must take in order to achieve its future carbon emissions reduction goals through 2030, as required by Colorado law.

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 SB 19-236 that impact, expand, and augment existing cost recovery. These new mechanisms consist of the expanded use of the RESA[4] for incremental cost recovery of clean energy resources (e.g., energy storage and generation interconnection costs, as opposed to just eligible energy resources).[5] Similarly, SB 19-236 establishes a new recovery mechanism, the CEPR, to recover additional costs attributable to meeting the carbon reduction goals of SB 19-236 and measured as the difference between the ERP Portfolio and the CEP Portfolio.[6] Furthermore, SB 19-236 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 Purchased Capacity Cost Adjustment ("PCCA") for purchased capacity costs, 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:

[4] § 40-2-125.5(4)(a)(VIII), C.R.S.
[5] § 40-2-125.5(2)(b), C.R.S.
[6] § 40-2-125.5(5)(a)(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 as part of its RE Plans.[7] Rule 3661 establishes that: (1) net retail rate impact of actions taken by the Company to comply with the 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 RES plan, should reflect the Company's plans and actions to acquire new eligible energy resources necessary to meet the

[7] 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.

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 SB 19-236 ADDRESS THE COSTS ASSOCIATED WITH A CEP?

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

- ***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.

- ***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.

Q. GIVEN THE FIRST ITEM ABOVE, DOES SB 19-236 MODIFY WHAT COSTS CAN BE RECOVERED BY THE RESA?

A. Yes. SB 19-236 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 SB 19-236. 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.[8] However, consistent with the terms of 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

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

collection level of one percent as of November 1, 2020.[9] In addition, Decision No. C20-0700 directs 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 BEYOND DECEMBER 31, 2022, AND IF SO, AT WHAT LEVEL?

A. Yes, as I previously mentioned, the Company believes this RE Plan supports the extension of RESA collections past December 31, 2022, maintaining the collections at the one percent collection level. The Company anticipates needing revenue from the RESA at this level through the duration of this RE Plan and through 2030. 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 can 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 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

[9] 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.

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. HAVE THERE BEEN ANY MODIFICATIONS TO THE RES RULES THAT CHANGE OR MODIFY THE COMPANY'S RES FILING/MODELING REQUIREMENTS OR RESA RECOVERY?

A. No. As of the date of the filing of this RE Plan, the Commission has engaged stakeholders in one workshop on potential future revisions to the RES rules. The Company anticipates that a new RES Notice of Proposed Rulemaking may open in 2022.

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 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 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 maximum of 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.

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 may create additional resource needs (not limited to renewable resources), including costs associated with: (1) retirement of existing generating facilities; (2) changes in system operation; and/or (3) any other necessary actions.[10] The Company translates these provisions to mean that Public Service is to recover the additional costs between the ERP Portfolio and the CEP Portfolio, less amounts that are funded through the RESA and other rider mechanisms, through the CEPR recovery mechanism.

[10] § 40-2-125.5(4)(a)(III), C.R.S.

III. THE RESA

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

A. In this section of my Direct Testimony, I summarize how the Company proposes to collect RES costs through the RESA, assuming it is extended by the Commission.

Q. WHAT IS THE RESA?

A. As described earlier, the RESA is an adjustment mechanism that allows the Company to recover up to an additional 2 percent of each customer's total electric bill to fund renewable energy activities and actions.[11] 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 40-2-124(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. DOES THE COMPANY PROPOSE TO MAINTAIN THE CURRENT ALLOCATION OF COST RECOVERY FOR RENEWABLES BETWEEN THE ECA AND RESA?

A. Yes. Public Service plans to use the same cost recovery mechanisms for its 2022-25 RE Plan that the Commission approved for prior RE Plans, namely: (1) the ECA to recover the costs of Eligible Energy that match the costs of the avoided non-renewable resources; and (2) the RESA to recover: (a) Eligible Energy costs that

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

are incremental to the costs of the avoided non-renewable resources; and (b) the program and administration costs. Included in the calculation of costs paid for by the ECA is an equivalent avoided cost for the solar production from our Solar*Rewards® systems. Because the Solar*Rewards costs are charged to the RESA, a separate calculation of the avoided costs equivalent to the production is performed and these costs are charged against the ECA and credited to the RESA.

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

A. First, the ECA accounts for the modeled avoided cost associated with RESA eligible energy resources. As mentioned earlier in my testimony, 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-RES" Scenario) where the Company could have chosen a non-eligible energy resource.[12] 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) sets forth what is included in the RES/No-RES model.

[12] Section 40-2-124, C.R.S. specifically states: "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."

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 "2006 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

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 ERP, subject to any modifications approved in the RE 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 "2006 Time Fence." In accordance with Commission Rules and decisions, resources acquired before July 2, 2006 are considered behind the Commission-created "2006 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.[13] These resources include Company-owned hydroelectric plants and certain wind resources (Cedar Creek I, 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

[13] 4 CCR 723-3-3661(h)(III).

No. C16-1075 approving the three-case 2016 Comprehensive Settlement Agreement ("2016 Three Case Settlement"),[14] including the 2017-19 RE Plan. Page 75 of the 2016 Three Case Settlement (Proceeding Nos. 16AL-0048E, 16A-0055E, and 16A-0139E) 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.[15]

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 the system over the cost of a non-renewable resource and allocates RESA dollars based upon that projection. To the extent that the Company's recalculation of the incremental cost of the acquisition is greater (for example, 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 cost of a project is "locked down," such costs would be fixed for the purpose of determining its impact on the RESA budget in future

[14] 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 its 2017-19 RE Plan) were combined for purposes of settlement. The resulting settlement approved in this proceeding is commonly referred to as the "Three Case Settlement."
[15] Proceeding No. 19A-0369E (Public Service's 2020-21 RE Plan).

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 RE Plan filing until the lock-down period expires.[16] 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.[17]

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.

[16] 4 CCR 723-3-3661(h)(V).
[17] Proceeding 08A-532E, Decision No. C09-1037, ¶ 43 (mailed Sept. 17, 2009).

- ***Group 3 – Locked Colorado Energy Plan/2020-21 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 2020-21 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 in this Proceeding to lock the modeled cost impacts from Group 2 and Group 3 for the life of those resources. This is discussed in more detail in the next section of my testimony.

Q. HOW DOES THE COMPANY PLAN TO ACCOUNT FOR COSTS AND COST RECOVERY UNDER THE RESA AND THE RELATED PROVISIONS OF SB 19-236?

A. The RESA has long been defined by the RES/No-RES process for eligible energy resources. When the RESA provisions under SB 19-236 are combined with the existing RESA provisions under Rule 3661, it has the effect of 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 costs, 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

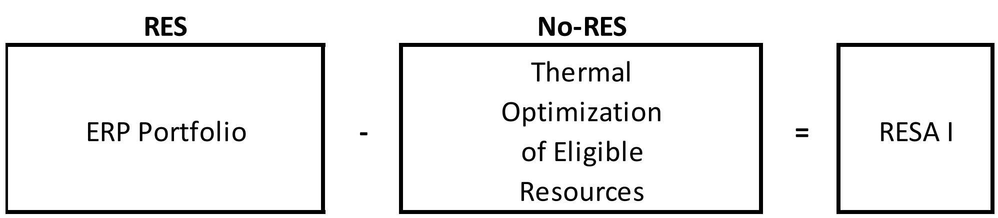
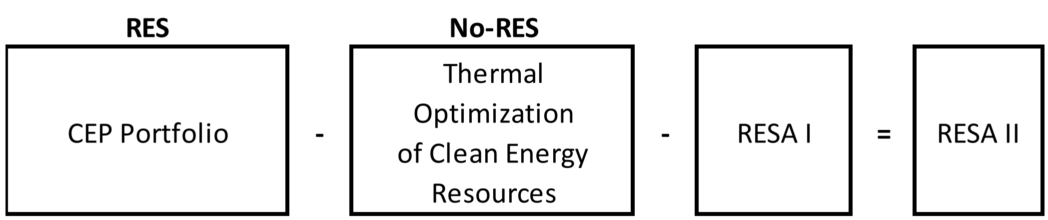


FIGURE AGT-D-4: Basic Elements of RESA II



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 they also depend 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 energy resources in future years.

Q. HOW DOES THE COMPANY EVALUATE AND RECORD THE INCREMENTAL COSTS FOR EACH RESOURCE?

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 $/MWh incremental cost.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THIS PROCEDURE?

A. Yes. In the next section of my testimony, I discuss a simplified method of assigning incremental and avoided costs to new non on-site solar eligible energy resources for the purpose of recording the net RESA transfer from the ECA.

A. <u>Assigning Incremental and Avoided Costs to New Resources</u>

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

A. As mentioned earlier, the Company models incremental costs on a portfolio basis. However, for the purpose of recording the net RESA transfer from the ECA the Company attributes an incremental $/MWh cost to estimated potential generation from each non on-site solar eligible energy resource.

Q. IS THE COMPANY PROPOSING TO MODIFY THE PRACTICE FOR ASSIGNING INCREMENTAL COSTS?

A. Yes. For efficiency's sake given the significant new renewable energy resources the Company has recently procured and expects to procure going forward, the Company is proposing to develop an average avoided $/MWh cost for "resource categories," such as wind, solar, and storage. The Company will aggregate purchase power agreement ("PPA") 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 basis as previously designed.

Q. HOW IS THAT DIFFERENT FROM PREVIOUS PROCEDURES FOLLOWED TO RECORD THE RESA NET INCREMENTAL ENTRIES?

A. The previous procedure Public Service followed for attributing incremental costs to individual resources was to run a RES/No-RES model for *each individual resource* (non on-site resources) and then adjust the combined result of each RES/No-RES modeling to match the RES/No-RES modeling for the portfolio. The Company's proposed procedure will match what has historically been followed for on-site solar projects.

Q. WHY IS THE COMPANY PROPOSING THIS SIMPLIFIED PROCEDURE FOR RECORDING INCREMENTAL AND AVOIDED COSTS GOING FORWARD?

A. The original process was developed at the inception of the RESA when there was a much smaller volume of renewable resources on the system. By extension, the complexity of the approach was less burdensome. However, 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. As I mentioned above, the Company has procured many new renewable energy resources and expects this trend to continue, and it will become less cumbersome to model these resources categorically rather than individually. Additionally, this method provides a more common-sense approach to recording incremental and avoided costs.

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 second, it would be more intuitive. This is important given the RES/No-RES model has caused significant confusion for intervenors as its complexity has increased over time with changes on the 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. ARE THERE OTHER BENEFITS TO USING THIS NEW METHODOLOGY?

A. Due to the nature of the Company's future portfolio, namely the increasing levels of intermittent renewable resources, I anticipate greater curtailment volatility may occur. This is simply due to a larger portion of the overall resource 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 to assess a long-term incremental $/MWh cost, it does little to protect 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 volatility in the actual output of the wind facilities versus the modeled output.

Because the RESA is currently the balancing rate mechanism, if there are more (or less) wind curtailments 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. Under this method, since the Company often pays for wind curtailment on a per-MWh basis, the costs of additional curtailment costs would go against the RESA deferred balance. To the extent that this procedure results in deferred RESA costs that are substantially higher than forecasted over the RE Plan period (2022-2025), the Company may propose in the future to move back to the previous method of assigning a fixed $/MWh of incremental costs (as opposed to avoided costs) to each non on-site solar eligible energy resource to ensure that the RESA deferred balance does not materially deviate from the Company's long-term projection.

Q. DOES THIS MODIFIED PROCEDURE RESULT IN INCREASED INCREMENTAL COSTS?

A. No. This procedure does not change the modeled incremental costs that the Company anticipates recording to the RESA.

Q. DOES THIS PROCEDURE APPLY TO ALL ELIGIBLE ENERGY RESOURCES OR JUST NEW ELIGIBLE ENERGY RESOURCES?

A. This procedure would only apply to new eligible energy resources. As discussed in the next section, the Company is proposing to lock the modeled cost impacts associated with resources procured prior to 2022. Therefore, the related procedures to record incremental and avoided costs will not change for eligible energy resources procured prior to 2022.

IV. THE 2021 TIME FENCE: EXTENDING LOCKED COST TREATMENT

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 "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 toward 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?

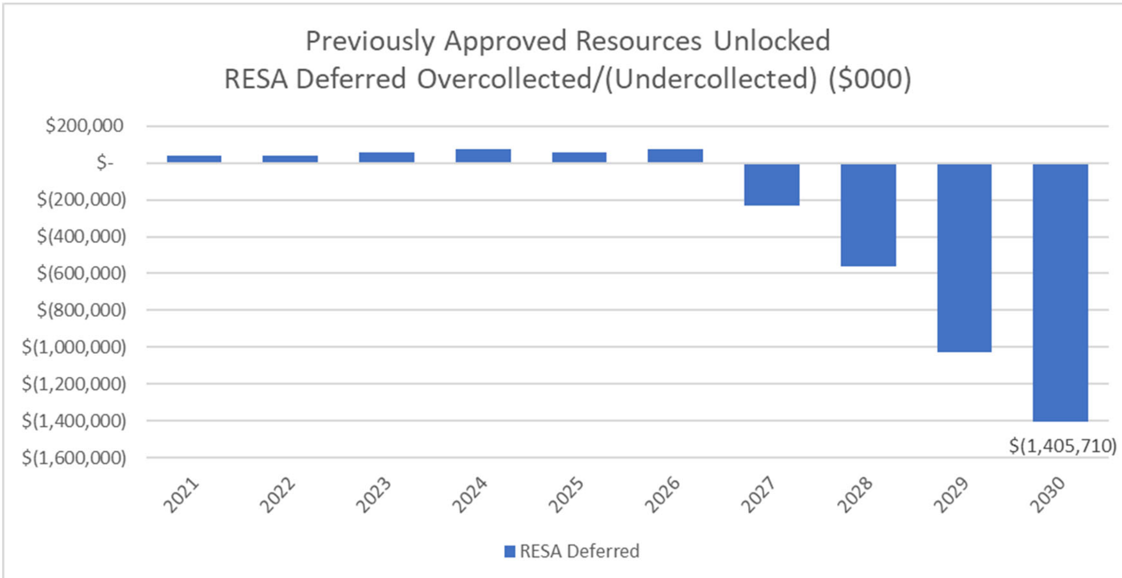
A. Public Service remains concerned that any mandatory retrospective calculation of incremental costs could jeopardize the recovery of costs previously approved through Commission decisions in the event of a potential flattening or decrease in natural gas prices from prior projections, which would materially increase the incremental costs of these resources. In Decision No. C08-0559 addressing the

Company's 2008 RE 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. The impact would be significant. 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 if these resources are unlocked. Figure AGT-D-5 presents an unlocked view of the RESA deferred balance for 2021-2030:

FIGURE AGT-D-5: Unlocked RESA Deferred Balance

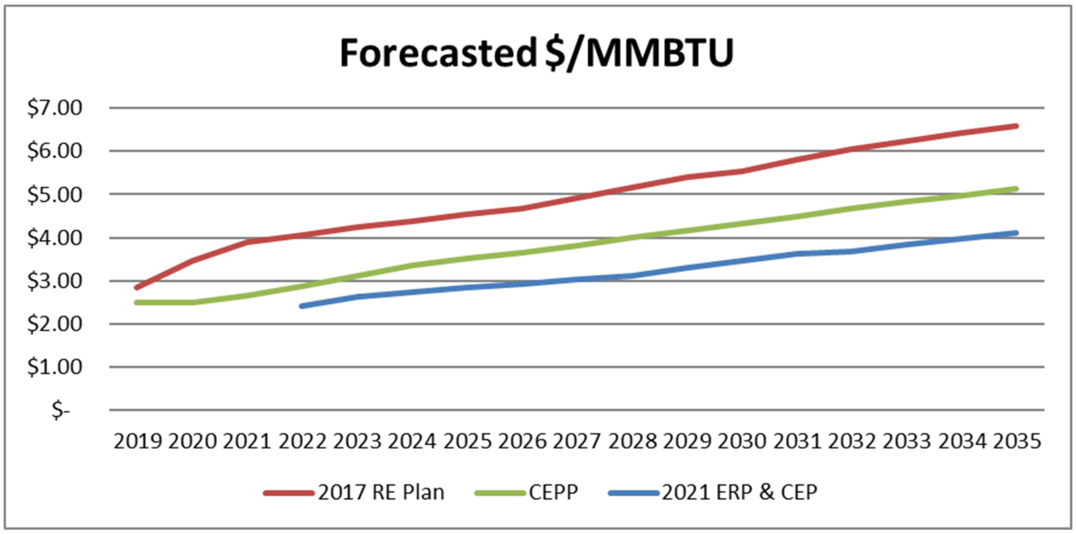


Q. WHY DO UNLOCKED RESOURCES RESULT IN SUCH A LARGE INCREMENTAL COST SHIFT STARTING IN 2027?

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 the 2016 ERP (Colorado Energy Plan), we see that gas prices in the current forecast are approximately 40 percent 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,[18] the 2016 ERP (Colorado Energy Plan),[19] and the current gas forecast (2021 ERP & CEP):

FIGURE AGT-D-6: Historic vs Actual Forecasted $/MMBTU



Q. WHAT 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 was made. Similarly, the same principle should apply to the impact on the RESA from the acquisition of 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,

[18] The natural gas prices used in the 2017-19 RE Plan were based on the forecast from the 1st quarter of 2016.
[19] 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…[20]

This framework and rationale are as germane today as they have been over the last decade.

[20] Proceeding No. 08A-532E, Decision No. R09-0549, ¶¶ 73-74 (mailed May 22, 2009), affirmed in pertinent part by Decision No. C09-1037, ¶ 43 ("For purposes of this docket and for SunE Alamosa and the on-site solar resources acquired so far, we uphold the Recommended Decision and "lock down" these respective costs consistent with the cost provided in the record.").

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.

V. 2021-2030 RESA DEFERRED BALANCE

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

A. In this section of my Direct Testimony, I summarize the components of the RESA deferred balance and retail rate impact.

Q. PLEASE PROVIDE MORE INFORMATION ON THE RESOURCES THAT ARE INCLUDED IN BOTH THE RES AND NO-RES PLAN SCENARIOS AND/OR BEHIND THE TIME FENCE.

A. Two categories of resources are included in both the RES and No-RES Plan scenarios. The cost impact of these locked resources is shown in Attachment JWI-2, Table 7-2(b). The first category of resources included in both the RES and No-RES Plan scenarios are those resources behind what is called the "2006 Time Fence." In accordance with Commission rules and decisions, resources acquired before July 2, 2006 are considered behind the Commission-created "2006 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.[21] These resources include Company-owned hydroelectric plants, a waste to energy facility, and certain wind resources (Cedar Creek I, Logan, Peetz, Spring Canyon, and Twin Buttes).

[21] *See* 4 CCR 723-3-3661(h)(III).

The second category of resources included in both the RES and No-RES Plan scenarios are resources explicitly locked down by Commission order or proposed by the Company to be locked down in the 2021 Time Fence.

Q. PLEASE EXPLAIN HOW THE "LOCKED DOWN" COSTS ARE INCLUDED IN THE DATA PRESENTED IN TABLES 7-1 TO 7-3 OF ATTACHMENT JWI-2.

A. "Locked down" incremental costs means that a specific $/MWh rate or total annual incremental cost for a specific resource for a specific period of time, and that these incremental cost calculations are "locked down" and not revisited or re-determined in an RE Plan filing until the lock-down period expires.[22] The purpose of the lock-down rule is to provide the customers and utility with some 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.

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 a summary of the projected balance through 2030, excluding the CEP-related RESA II costs. This projection assumes 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 $5 million by 2030. While this projection does result in a relatively small under-collected ending

[22] *See* 4 CCR 723-3-3661(h)(V).

balance in the RESA in 2030, should costs be higher than expected, there are tools available (e.g., an increase in the RESA to its full statutory two 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	$ 46,656	$ 39,261	$ (7,395)	$ 3,110	$ (4,285)	$ 47,041
2022	$ 46,779	$ 32,867	$ (13,912)	$ 2,618	$ (11,294)	$ 35,746
2023	$ -	$ 33,093	$ 33,093	$ 3,415	$ 36,508	$ 72,255
2024	$ -	$ 33,925	$ 33,925	$ 5,826	$ 39,751	$ 112,005
2025	$ 53,166	$ 35,485	$ (17,682)	$ 6,737	$ (10,945)	$ 101,060
2026	$ 20,858	$ 36,673	$ 15,815	$ 7,116	$ 22,930	$ 123,991
2027	$ 31,282	$ 37,395	$ 6,114	$ 8,296	$ 14,410	$ 138,400
2028	$ 59,882	$ 38,132	$ (21,751)	$ 8,327	$ (13,423)	$ 124,977
2029	$ 101,692	$ 38,883	$ (62,809)	$ 6,110	$ (56,699)	$ 68,278
2030	$ 115,437	$ 39,649	$ (75,788)	$ 1,984	$ (73,804)	$ (5,525)

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

A. Column V of Table 7-2(c) (RESA Rolling Balance – Deferred) demonstrates that the RESA balance was positive (over-collected) at the end of 2020 by approximately $51.3 million. The positive RESA deferred balance is expected to decrease slightly to approximately $47.0 million by the end of 2021. After 2021, the RESA deferred balance is expected to stabilize and grow through 2027. This continued growth is largely attributable to many of the locked down resources that help offset incremental costs of more expensive resources. The Company forecasts that in 2023-2024, with a large portion of the eligible RES portfolio locked, the modeled incremental costs of the portfolio to the RESA are negated entirely. Then, as 2021 ERP & CEP resources come online in 2025 through 2030, we will experience an increase in RESA costs which draws down the over-collected balance of the RESA deferred account.

Q. ARE THERE LIMITATIONS TO THE USEFULNESS OF THIS FORECAST?

A. Yes, as mentioned previously, it is difficult to know the extent of change that will result when the Company updates it modeling assumptions through Phase II of the 2021 ERP & CEP (competitive acquisition and bid evaluation process). Given that the forecast is anticipated to change through updated modeling and assumptions in Phase II of the 2021 ERP & CEP, the Company recommends maintaining the incremental cost modeling established in Proceeding No. 19A-0369E (Public Service's 2020-21 RE Plan) for any new distributed generation resources until the Company has completed Phase II of the 2021 ERP & CEP. At that time, and through presentation of the Company's 120-Day Report, the Company will adopt the updated incremental and avoided cost modeling consistent with those results.

Q. HOW HAS THE COMPANY'S PROJECTION OF THE RESA DEFERRED BALANCE CHANGED FROM WHAT WAS PRESENTED IN THE 2021 ERP & CEP PROCEEDING?

A. The Company has updated the RESA forecast in this Proceeding from what was provided in its Direct and Rebuttal Testimony in the 2021 ERP & CEP to reflect updated revenue forecasts, RESA administration costs, and refined incremental costs assumptions, including additional costs associated with up-front payments for REC incentives and Battery Connect incentives. The Company's proposals in this Proceeding do not represent a material variation from what was presented in the 2021 ERP & CEP, with the exception of new cost elements (such as battery incentives) or prefunded REC incentives (that change the timing of RESA expenses) which were not contemplated in the 2021 ERP & CEP proposals. As I mentioned earlier, updates to the RESA deferred forecast will be more useful following the results of Phase II of the 2021 ERP & CEP.

Q. HAS THE COMPANY QUANTIFIED THE DIFFERENCE BETWEEN THE FORECAST OF DG RESOURCES ASSUMED IN PROCEEDING NO. 21A-0141E AND THE DG PROPOSALS MADE IN THIS PROCEEDING?

A. Yes. Based on my estimate, the Company's proposal is in line with what was presented in the 2021 ERP & CEP in terms of planned procured capacity and the overall cost of the RE Plan from a RESA deferred perspective. My evaluation takes into consideration the Company's historic project attrition as well as the maximum proposed program capacities.

Q. PLEASE SUMMARIZE THE PURPOSE OF THE OTHER TABLES INCLUDED IN VOLUME 2 OF THE 2022-25 RE PLAN (ATTACHMENT JWI-2), AND EXPLAIN THE INFORMATION PRESENTED IN THE TABLES.

A. Tables 7-1 through 7-3 present various details supporting the summary Table 7-3(c). The tables were designed to make certain information explicit, i.e.: the total cost of the eligible energy resources; the incremental portion of the total costs of the eligible energy resources that is recoverable through the RESA; and the avoided energy cost of the eligible energy resources that is recoverable through the ECA.

Table 7-1 is a summary of the total of both the unlocked and locked costs of eligible resource costs that are charged to the RESA deferred account. These costs are separated into their incremental cost (RESA charges) and avoided energy cost (ECA charges) components. The columns that contain the word “unlocked” in the column heading contain the costs for eligible energy resources which have not had their respective costs locked by Commission order or as proposed in this proceeding for the 2021 Time Fence. The columns that contain the word “locked” in the column heading contain the costs for eligible energy resources have had their costs locked by Commission order or as proposed in this proceeding for the 2021 Time Fence. If a resource had its costs locked for a finite period of time (i.e., not for the life of the resource), its costs will shift from the locked columns to the unlocked columns once the lock-down period for that resource has expired.

Q. PLEASE DESCRIBE EACH OF THE COLUMNS SET FORTH IN TABLE 7-1 OF ATTACHMENT JWI-2.

A. The column labeled “Total Renewable Energy Costs” sets forth by year the contracted or estimated total costs of the renewable resources in question. The unlocked incremental costs are calculated from the difference between the total modeled system costs of the RES and No-RES Plan scenarios. The locked incremental costs are the locked down incremental costs of the locked renewable resources as set by Commission order or as proposed in this proceeding for the 2021 Time Fence. Incremental costs are the additional costs above the avoided costs of the renewable resources which are recoverable through the RESA. The avoided costs are the modeled or locked "benefits" of the renewable resources which are recovered through the ECA.

Q. PLEASE DESCRIBE EACH OF THE COLUMNS IN TABLES 7-2(a) AND (b) OF ATTACHMENT JWI-2.

A. Table 7-2(a) provides the calculations for the incremental and avoided costs of the unlocked resources. Tables 7-2(a) and (b) contain identical calculations, the difference being 7-2(a) only contemplates unlocked resources and 7-2(b) only contemplates locked resources. Tables 7-2(a) and (b) are discussed in Section 7, but below I provide an overview of each column included in these tables:

- Columns B through D represent the total cost of renewable resources that are "unlocked," meaning their costs have not been locked down by previous proceedings and have been included in the RES, but not the No RES comparison. These costs do not include the costs of the Solar*Rewards program, which are identified separately in the Table.

- Column E, "Total Cost," is the summation of the costs shown in columns B through D.

- Column F, "B, C, D Modeled Incremental Cost", is the modeled incremental cost (difference between system costs of the RES and No-RES Plans) of the resources contained in columns B, C and D, and is recovered through the RESA.

- Column G, "B, C, D Calculated Avoided Cost", is the calculated avoided cost, or benefits, of the resources contained in columns B, C and D, and is calculated by subtracting the incremental cost in column F from the total cost in column E.

- Column H, "On-Site Solar Total Cost," is the total estimated cost of the Solar*Rewards and Solar*Rewards Community® programs. Column H in Table 7-2(a) contemplates the unlocked tranches of Solar*Rewards, and Column H in Table 7-2(b) contemplates the locked tranches of the Solar*Rewards program.

- Column I, "Modeled On-Site Solar Avoided Cost," is the modeled avoided costs of the On-Site Solar resources included in Column H. This is determined from the sum of modeled "benefits" or avoided costs calculated from a RES and No-RES Plan comparison, which only considers the Solar*Rewards and Solar*Rewards Community in question. For Table 7-2(b), the modeled avoided costs are for the tranches of Solar*Rewards that were locked by Commission order or as proposed in this proceeding for the 2021 Time Fence, and therefore were determined from the approved modeling assumptions used at the time their respective costs were locked. The locked avoided costs for the two tranches of Solar*Rewards which have their incremental costs locked are detailed in Tables 7-3(a) and (b).

- Column J, "Calculated On-Site Solar Incremental Cost," is the calculated incremental cost of the Solar*Rewards and Solar*Rewards Community tranches contained in Column H, and is calculated by subtracting the avoided cost in column I from the total cost in Column H.

- Column K, "Total Costs," is a sum of the total costs of resources from columns F and H. For Table 7-2(a) this is the total cost of unlocked resources, for Table 7-2(b) this is the total cost of locked resources.

- Column L, "Incremental Costs," is a sum of the incremental costs of resources from columns F and J. For Table 7-2(a) this is the incremental cost of unlocked resources, for Table 7-2(b) this is the incremental cost of locked resources (as set by Commission Order or as proposed in this proceeding for the 2021 Time Fence).

- Column M, "Avoided Costs," is a sum of the avoided costs of resources from columns G and I. For Table 7-2(a) this is the avoided cost of unlocked resources; for Table 7-2(b) this is the avoided cost of locked resources.

Q. PLEASE DESCRIBE EACH OF THE COLUMNS SET FORTH IN TABLE 7-2(c).

A. Table 7-2(c) is a summary which pulls together the components from Tables 7-2(a) and (b) and ultimately calculates the impact to the RESA account. Although a discussion of the various columns on Tables 7-2(c) is included in Section 7 of Attachment JWI-1, I provide a high-level overview of this table below:

- Columns B and C represent the total estimated cost of renewable resources that have their incremental costs collected by the RESA. Column B contains the total cost of unlocked resources and column C contains the total cost of locked resources.

- Columns D and E are the incremental costs of resources which are recoverable through the RESA.

- Column F contains the portion of RESA costs that are associated with the CEP that are allocated to be recovered through the CEPR.

- Column G contains the additional costs associated with up-front payments for REC incentives and Battery Connect.

- Column H contains the estimated Wholesale Customer share of incremental renewable resource costs.

- Column I contains the Program and Administration costs recoverable by the RESA rider.

- Columns J through L are estimates of the various sources of revenue to pay for costs borne by the RESA; this includes RESA rider revenue, estimated Windsource revenue, and projected Hybrid REC Margins (if any). Consistent with Rule 3660(l) the Company is required to offer our full requirements wholesale customers a load ratio share of the RECs commensurate with their service so long as they reimburse the Company for the cost of the resource and administrative responsibilities for such transactions which are performed consistent with our Federal Energy Regulatory Commission-approved contracts.

- Columns M and N are the avoided cost portions of the renewable resources cost. These costs are collected by the ECA and do not factor into the calculation of the RESA balance, they are provided for informational purposes only.

- Column P is a sum of the total estimated renewable resource costs. The incremental portions of these costs are collected by the RESA, and the avoided portion is collected by the ECA.

- Column Q is a sum of all costs to be recovered through the RESA. This includes the incremental costs of locked and unlocked resources as well as RESA program administration costs.

- Column R is a sum of all revenues used to pay for the costs borne by the RESA.

- Columns S, T, U, and V include the annual excess or deficiency calculation (calculated from the difference of columns Q and R), the interest calculations for the deferred balance, and the RESA rolling balance calculations.

Q. PLEASE DESCRIBE TABLES 7-3(a) AND (b).

A. Table 7-3(a) provides a summary of the locked for life incremental costs for resources that transfer their incremental costs from the ECA to the RESA, and the locked for life avoided costs for resources that transfer their avoided costs from the RESA to the ECA (Solar*Rewards pre-2009). Table 7-3(b) provides the same information, but in greater detail with full calculations.

VI. OTHER MATTERS

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

A. I discuss the Company's recommendation of credit pricing values associated with its new Off-Site Solar program.

A. SRCS Off-Site Net Metering Credit

Q. PLEASE DESCRIBE THE NEW OFF-SITE SOLAR PROGRAM PROPOSED IN THE 2022-25 RE PLAN.

A. Company witness Ms. Klemm provides the details of this program in her Direct Testimony. However, at a high level, the Off-Site Solar program was enacted under Senate Bill 21-261 ("SB 21-261") to allow for individual customers to locate solar facilities at one or more premise(s) located within Public Service's service territory and provide virtual net metering credits to their other premise(s) under the same account that are non-contiguous properties.

Q. PLEASE DESCRIBE THE NET METERING CREDIT PROVISIONS OF SB 21-261 ASSOCIATED WITH THE OFF-SITE SOLAR PROGRAM.

A. Section 40-2-124(1)(e)(I)(C), C.R.S., as modified by SB 21-261 states:

> "For retail distributed generation that is used to meet loads of a noncontiguous property owned or leased by the customer, a qualifying retail utility's net metering program must provide the customer a net metering credit minus a reasonable charge, as determined by the commission, to cover the utility's costs of delivering to the customer's premises the electricity generated by the retail distributed generation and of administering the off-site net metering credits. The reasonable charge shall be fixed for the term of the interconnection agreement pertaining to the retail distributed generation facilities and shall be determined by a utility tariff filing, which may be updated once annually."

(Emphasis added.)

Q. WHAT IS THE COMPANY'S RECOMMENDATION FOR DETERMINING THE NET METERING CREDIT, AS WELL AS THE ASSOCIATED REASONABLE CHARGE?

A. This program would fit well under the existing SRCS tariff that is currently in place for Community Solar Garden ("CSG") projects under the Solar*Rewards Community program, the exception being that the Off-Site Solar program would have different net metering credits by virtue of having a fixed reasonable charge for the term of the interconnection. I will first describe the Solar*Rewards Community program for CSGs and then describe how a fixed reasonable charge would be determined to augment the net metering credit to comply with SB 21-261.

Q. PLEASE PROVIDE A BACKGROUND ON CSGS AND THE SOLAR*REWARDS COMMUNITY PROGRAM.

A. In 2010, CSGs were created with the passage of House Bill 10-1342 (§ 40-2-127, C.R.S.). The statute was later revamped to create a more comprehensive CSG program as an alternative means for customers to receive the beneficial use of the electricity generated by solar panels.

Public Service launched Solar*Rewards Community in Colorado in 2012. In Colorado, the Company enables Solar*Rewards Community for customers who want to participate in shared, centralized solar installations. CSGs are an option for customers who want to support solar energy but lack certain qualities (physical (i.e., roof space, shading, etc.) or financial) to install systems on-site. Solar developers build community-based shared solar installations interconnected to

Public Service's system and offer subscriptions with various purchase arrangements to customers. Solar developers and their projects are not regulated by the Commission.

In 2012, the Company introduced the SRCS Credit in its RE Plan application in Proceeding No. 11A-418E. Since then, there have been several significant legislative and Commission proceedings that have further shaped CSGs and the Company's Solar*Rewards Community program.

Q. WHAT ARE THE VARIOUS COMPONENTS THAT MAKE UP THE BILL CREDIT FOR CSGS TODAY?

A. First, there are two sets of SRCS Credits that the Company recalculates each year: (1) the Total Aggregate Fixed Retail Rate ("TAFRR"); and (2) the Total Aggregate Variable Retail Rate ("TAVRR"). The TAFRR is a rate class average per-kWh rate calculated for each of the Company's rate classes, and was implemented for participating customers after January 1, 2017. The TAVRR is a customer specific per-kWh rate that is available to customers participating in a Solar*Rewards Community resource prior to January 1, 2017. The TAVRR is not available to customers participating after January 1, 2017. Table AGT-D-3 below provides a representation of the retail rate components for Schedule SG which I will refer to as Total Aggregate Retail Rate ("TARR"). The presentation requires the Company to convert average rates to a kWh basis using a conversion factor developed in the Company's most recent Phase II electric rate case in Proceeding No. 20AL-0432E. The table is broken into two sections: (1) the base rate element of the TARR; and (2) the rider rate element of the TARR.

TABLE AGT-D-3: Total Aggregate Retail Rate

SG, SG CPP, STOU, SPVTOU, SST			
	$/kW-mo	Conversion	$/kWH
Base Energy Charge			$0.00791
G&T Summer	$15.15	0.0992%	$0.01503
G&T Winter	$9.09	0.1736%	$0.01578
Distribution	$6.17	0.2802%	$0.01729
TARR before Riders			**$0.05601**
Riders			
ECA			$0.03288
PCCA	$1.00	0.2728%	$0.00273
TEPA	$0.18	0.2728%	$0.00049
TCA	$0.53	0.2728%	$0.00145
DSMCA	$0.47	0.2728%	$0.00128
CEPA	1%		$0.00095
RESA	1%		$0.00095
Total Rider			**$0.04073**
Total TARR			**$0.09674**

The TAFRR and TAVRR are the equivalent to the "net metering" rate that on-site solar customers receive for their production of electricity. These are the starting points from which certain base rate and rider billing elements are subtracted to determine the final net rate that will be used as the SRCS Credit which is then applied to customer's bills based upon their share of production from the CSG. Generally, the Company has removed elements of "delivery" from the rates from the TAFRR and TAVRR, which include transmission and distribution costs. Additionally, the Company subtracts other elements, such as the demand-side management ("DSM") and RESA rate components, which are required to be deducted by rule. The Company has historically subtracted the RESA component since the inception of the SRCS Credit in Proceeding No. 11A-418E. Table AGT-

D-4 below presents the Company's subtraction of transmission, distribution, DSM, and RESA components (i.e., the reasonable charge):

TABLE AGT-D-4: CSG Credit - Remove T, D, DSM & RESA from TARR

SG, SG CPP, STOU, SPVTOU, SST		
	Conversion	$/kWH
Total TARR		**$0.09674**
Remove Transmission, Distribution, DSM and RESA		
TCA		($0.00145)
DSMCA		($0.00128)
Portion of Base that Is T,D&DSM	48.7%	($0.02726)
RESA		($0.00095)
Total T,D&DSM and RESA Reduction		**($0.03093)**
SRCS Fixed Credit		**$0.06580**

Q. HOW DOES THE COMPANY DEVELOP THE PERCENTAGE PORTION OF TRANSMISSION, DISTRIBUTION, AND DSM THAT IS IN THE TARR TO ADJUST THE CREDIT?

A. The Company utilizes the Class Cost of Service Study included with the last approved Phase II electric rate case. Table AGT-D-5 presents the percentage portion of base rates that are made up of percentage portion of transmission, distribution, and DSM.

TABLE AGT-D-5: Base Rate Portion - Credit Adjustment

	Residential	Small Commerical	C&I Secondary	C&I Primary	C&I Transmission
Production	$ 275,380,235	$ 32,572,555	$ 244,180,834	$ 56,687,821	$ 31,294,001
Transmission	95,325,737	11,275,329	84,525,740	19,623,080	10,832,744
Substations	42,507,393	5,026,491	37,666,010	8,739,085	-
Primary	151,630,639	17,892,638	131,866,552	27,832,648	-
Secondary	53,075,054	5,061,839	32,629,739	-	-
Variable	72,075,709	10,101,914	93,070,114	27,646,401	17,656,648
DSM	39,309,564	4,834,406	33,000,814	7,361,952	3,212,307
Total	$ 729,304,331	$ 86,765,172	$ 656,939,803	$ 147,890,987	$ 62,995,700
T, D & DSM	$381,848,387	$44,090,703	$319,688,855	$63,556,765	$14,045,051
T,D&DSM as a % of Total	**52.4%**	**50.8%**	**48.7%**	**43.0%**	**22.3%**

Q. HOW DOES THE COMPANY PROPOSE TO ESTABLISH THE FIXED REASONABLE CHARGE FOR ITS OFF-SITE SOLAR PROGRAM?

A. Because the statute requires that the reasonable charge be fixed for the term of the interconnection, the Company is recommending the reasonable charge for the Off-Site Solar Program be based on forecasted Transmission, Distribution, DSM and RESA costs, then levelized into a single $/kWh reasonable charge adjustment to the TARR. Table AGT-D-6 below presents the Company's subtraction of transmission, distribution, DSM, and RESA components (i.e., the reasonable charge) for the Off-Site Solar program:

TABLE AGT-D-6: Off-Site Credit - Remove T, D, DSM & RESA from TARR

SG, SG CPP, STOU, SPVTOU, SST	
	$/kWH
Total TARR	**$0.09674**
Remove Transmission, Distribution, DSM and RESA	
Transmission	($0.01298)
Distribution	($0.03424)
DSMCA and DSM in Base	($0.00472)
RESA	($0.00122)
Total T,D&DSM and RESA Reduction	**($0.05316)**
Off-Site Fixed Credit	**$0.04358**

Q. WHAT IS THE BASIS FOR THE COMPANY'S FORECAST OF TRANSMISSION, DISTRIBUTION, DSM, AND RESA COSTS?

A. The Company used the 15-year forecast presented in the Supplemental Direct testimony of Ms. Deborah A. Blair in Proceeding No. 21AL-0317E (2021 Phase I Electric Rate Case) for the Transmission, Distribution, and RESA elements. For the DSM and DSM Cost Adjustment ("DSMCA") components, the Company used 2022 SRCS calculated components and escalated those rates at two percent (to represent general cost inflation) for the 15-year time period.

Q. WHAT ADDITIONAL SUPPORT IS THE COMPANY PROVIDING FOR ITS CALCULATION?

A. Please see Attachment AGT-1, SRCS Off-Site Net Metering Credit, which provides detailed support of the calculation.

Q. HOW OFTEN DOES THE COMPANY PROPOSE TO UPDATE THE OFF-SITE NET METERING CREDIT?

A. The Company will update the credit rate annually to reflect changes in the TARR. However, the fixed reasonable charge will only be updated to coincide with future RE Plan filings.

Q. HOW DOES THE OFF-SITE SOLAR PROGRAM CREDIT COMPARE TO THE EXISTING CSG CREDIT?

A. Because the fixed reasonable charge under the Off-Site Solar program is based on forecasted costs and then levelized, the reasonable charge under the Off-Site Solar program is higher than under the CSG program. Therefore, the net metering credit awarded under the Off-Site Solar program, for example in 2022, is lower than the net metering credit awarded under the CSG program. Table AGT-D-7 presents the 2022 net metering credit under the CSG program versus the net metering credit under the Off-Site Solar program.

Table AGT-D-7: CSG vs Off-Site Net Metering Credit $/kWh

Rate Service Schedule	Current Fixed Credit	Proposed Fixed Credit	$/kWh Difference	% Difference
R, RE TOU, RD	$ 0.07510	$ 0.04304	$ (0.03206)	-42.7%
C, C-TOU, NMTR	$ 0.07010	$ 0.05483	$ (0.01527)	-21.8%
SG, SG CPP, STOU, SPVTOU, SST	$ 0.06580	$ 0.04358	$ (0.02222)	-33.8%
S-EV	$ 0.07507	$ 0.06144	$ (0.01363)	-18.2%
SGL	$ 0.07756	$ 0.06606	$ (0.01150)	-14.8%
PG, PG CPP, PTOU, SCS-7, PST	$ 0.05825	$ 0.04460	$ (0.01365)	-23.4%
TG, TG CPP, TTOU, SCS-8, TST	$ 0.05356	$ 0.04800	$ (0.00556)	-10.4%

Q. AS A RESULT OF THE PROPOSED CHANGES, WHAT TARIFF MODIFICATIONS DOES THE COMPANY PROPOSE FOR COMMISSION APPROVAL?

A. The Company would need to modify Sheet Nos. 114B through 114G of its COLO. PUC No. 8 Electric Tariffs in order to incorporate the Off-Site Solar Credit. These illustrative tariffs are provided as Attachment AGT-2 to my Direct Testimony.

B. <u>2017-2021 RESA Audit</u>

Q. WAS THERE A PROVISION IN THE 2020-21 RE PLAN THAT DIRECTED THE COMPANY AND STAFF TO CONFER ON THE SCOPE AND BUDGET FOR A THIRD-PARTY AUDIT?

A. Yes, Decision No. R20-0099 in Proceeding No. 19A-0369E stated, “The ALJ finds that it is in the public interest to require the Company and Staff to confer on the scope and budget for a third-party audit, and if they agree, to present their proposal for the Commission to consider in the Company’s next plan, and directs them to do so. The ALJ draws no conclusion as to whether such an audit should ultimately be required.”[23]

Q. HAS THE COMPANY CONFERRED WITH STAFF ON THE SCOPE OF A POTENTIAL RESA AUDIT?

A. Yes, the Company conferred with Staff on the scope of a potential RESA audit by a third party prior to the filing of this Plan. The details and scope of the audit have not yet been developed, but the Company and Staff generally agreed that: (1) the

[23] Proceeding No. 19A-0369E, Decision No. R20-0099, ¶ 161 (mailed Feb. 14, 2020).

audit should cover a five-year period (2017-2021); (2) the audit should provide an evaluation of processes and procedures by which the Company administers the RESA; (3) the audit should review, on a sample basis, PPA payments, REC payments, administrative costs, and incremental cost entries; and (4) the cost of the audit would be borne by the RESA recovery mechanism. The Company and Staff also agreed that Staff would have an opportunity to review the Scope of Work proposed by the third party for the audit services and proposed costs.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. First, I recommend that the Commission authorize the Company to maintain RESA collections at the one percent collection level. The Company anticipates needing revenue from the RESA at this level through the duration of this Plan and through 2030. Second, I recommend that the Commission accept the Company's 2021 Time Fence recommendation regarding previously approved resources. Third, I recommend that the incremental and avoided costs associated with DG procurement approved in this 2022-25 RE Plan be established following Phase II of the Company's 2021 ERP & CEP, after the receipt of actual bids and updated pricing assumptions. Finally, I recommend that the Commission approve the Company's methodology for calculating the off-site net metering credit for the Off-Site Solar program.

Q. DOES THIS CONCLUDE YOUR DIRECT 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), 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. 2012-2013, 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. In 2014, I 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

* * * * *

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2022–2025 RENEWABLE ENERGY COMPLIANCE PLAN	)))) **PROCEEDING NO. 21A-____EG**)))

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 17th day of December 2021.

Alexander G. Trowbridge
____
Alexander G. Trowbridge
Pricing Consultant

Subscribed and sworn to before me this 17th day of Dec., 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