**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-0141E**

UPDATED NON-UNANIMOUS PARTIAL SETTLEMENT AGREEMENT

CONTENTS

INTRODUCTION AND IDENTIFICATION OF PARTIES

This Updated Non-Unanimous Partial Settlement Agreement ("Settlement Agreement" or "Agreement") is filed on behalf of Public Service Company of Colorado ("Public Service" or the "Company"), Trial Staff ("Staff") of the Colorado Public Utilities Commission ("Commission"), the Colorado Office of the Utility Consumer Advocate ("UCA"), the Colorado Energy Office ("CEO"), the City and County of Denver ("Denver"), the Board of County Commissioners of Pueblo County ("Pueblo County"), the City of Pueblo and the Board of Water Works of Pueblo, Colorado ("PBWW"), the Colorado Independent Energy Association ("CIEA"), the Colorado Office of Just Transition ("OJT"), Holy Cross Electric Association, Inc. ("Holy Cross"), the Colorado Oil & Gas Association ("COGA"), the Colorado Solar and Storage Association and Solar Energy Industries Association (collectively, "COSSA/SEIA"), the International Brotherhood of Electrical Workers, Colorado Independent Energy Association ("CIEA"), Interwest Energy Alliance ("Interwest"), Local No. 111 ("IBEW"), Onward Energy Management, LLC ("Onward"), the Rocky Mountain Environmental Labor Coalition and Colorado Building and Construction Trades Council, AFL-CIO (collectively, "RMELC/CBCTC"), Sierra Club and the National Resources Defense Council (collectively the "Conservation Coalition"), Walmart Inc. ("Walmart"), and Western Resource Advocates ("WRA"), (each a "Settling Party" and collectively the "Settling Parties").

This Settlement Agreement is intended to resolve numerous issues (the "Settled Issues") raised by the Settling Parties in this Proceeding with respect to the Company's

Verified Application ("Application") for Approval of its 2021 Electric Resource Plan and Clean Energy Plan ("2021 ERP & CEP").

SETTLEMENT AGREEMENT

The following terms comprise the Settlement Agreement reached by the Settling Parties.

I. Phase II Modeling Inputs and Assumptions

The Settling Parties agree to the following terms for Phase II modeling inputs and assumptions:

1. *Social Cost of Carbon ("SCC") Value.* The Company will utilize a SCC value beginning at $68/short ton.[1] The SCC values will be based upon the February 2021 update to the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990*, published by the federal Interagency Working Group on Social Cost of Greenhouse Gases, and use the 2.5 percent discount rate from that publication. The Company will use the values from the cited report, converted to dollars per short ton and expressed in nominal dollars as appropriate, unless further updates are published prior to the commencement of the Phase II competitive solicitation. If the federal Interagency Working Group publishes updates that either recommend using a lower discount rate for the SCC, or that recommend higher values for the SCC prior to the issuance of the Phase II Request for Proposals ("RFP"), the Company will use the updated discount rate and updated values. The Settling Parties further agree that the Company will present optimized portfolios based upon the portfolio development framework approved by the Commission in its Phase I Decision using both $0/ton and SCC values. The number of portfolios presented

[1] § 40-3.2-106(4), C.R.S.

will ultimately depend upon the framework approved by the Commission in its Phase I Decision.

2. *Phase II Generic Resource Cost Values.* The Company will update the costs for generic resources to the most recent vintage (2021) of the National Renewable Energy Laboratory Annual Technology Baseline ("NREL ATB") prior to release of the RFP in Phase II. The Company will make similar changes to those in the NREL ATB workbooks to comport with assumed wind and solar net capacity factors at 50 percent and 30 percent, respectively, as well as changes to comport with Colorado state tax rates, federal tax credits, and an inflation assumption consistent with the adjustments made to the 2020 NREL ATB workbooks.

3. *Phase II Transmission Modeling Constraints.* The Company will remove the "tunnel" modeling constraint that was implemented to represent an approximation of the impact of the construction schedule for the proposed Colorado's Power Pathway Project[2] ("Pathway Project") in the Phase I modeling. For Phase II modeling, the Company will not impose hard constraints on resource additions and instead will implement two actions: (1) applying a "pass/fail" due diligence screening to ensure a bid's proposed interconnection location and timing is physically possible (i.e., fully completed transmission and interconnection facilities will be available at the stated time) provided that if a bid's interconnection timing falls within a reasonable margin of error (90 days) of a valid interconnection date and would otherwise fail, the bidder will be given an

[2] Commission Proceeding No. 21A-0096E.

opportunity to cure within a reasonable time period (e.g., seven (7) days); and (2) adding a simplified transmission topology and flow limits by year to the EnCompass model to guide bid selection and economics.

4. *Phase II Tail Modeling.* For the following five portfolios in Attachment 1, the Company will optimize the EnCompass model runs in Phase II using the Annuity Tail method[3] in addition to the Replacement Chain method to bookend the measurement of the modeled effects of generation with different lives during the Planning Period: Portfolios 1, 2, 4, 5 and 9. The Company will only utilize the Replacement Chain method for the remaining sets of portfolios.

5. *Phase II Standalone Storage Effective Load Carrying Capability Values.* The Company will update its Effective Load Carrying Capability ("ELCC") for four-hour duration standalone energy storage projects and the storage component of hybrid generation/storage projects to 60 percent for the first 500 MW of storage and 40 percent for incremental capacity thereafter, to apply to Phase II bid review. Longer duration storage will be scaled from these values using the ratios derived from the results of the Company's ELCC study.[4] In addition, the Company will update its current ELCC study for standalone storage and the storage component of hybrid projects[5] to incorporate the

[3] Hearing Exhibit 1000, Answer Testimony of William A. Monsen, pages 60-65.

[4] Hearing Exhibit 114, Attachment KLS-2.

[5] Note that for the Phase II bid evaluation, the ELCC for the storage component of hybrid resources will be the value derived for the equivalent incremental standalone storage resource and the SERVM study will be for incremental 2, 4 and 8 hour standalone storage. The hybrid resource ELCC will be the sum of the standalone storage ELCC and the solar ELCC (also calculated on a standalone basis), subject to the sum not exceeding the interconnection agreement size for the facility.

methodological changes listed below ahead of the Phase II competitive solicitation. The updated study will use the same software (SERVM) and the same data set(s) as were used in the PRM Study submitted with the Company's Phase I application. The updated study will reflect the dynamic nature of the Public Service system, including embedded chronological storage scheduling. The Company will also perform a study assuming the expected increase in renewable capacity suggested in the Phase I modeling. Specifically, the Company should evaluate storage ELCC on a system with more renewables to ensure that the interactive, portfolio effects of the resources are captured. If this updated study results in a higher ELCC value for standalone storage than the values set forth above (e.g., 60 percent for the first 500 MW of storage and 40 percent for incremental capacity thereafter with scaling for longer and shorter duration storage resources), then the Company will use the higher of the values for the respective storage durations for the Phase II bid evaluation of standalone storage and the storage component of hybrid projects. The Company affirms that the ELCC is updated in each ERP and the Settlement Agreement here does not bind the Settling Parties to these values in the future. Furthermore, the Company commits to applying a modeling approach for ELCC and planning reserve margin ("PRM") in future ERP proceedings that reflects operating a grid with a high level of intermittent generation, that (absent good cause shown) utilizes the same modeling software and inputs for both studies, and that reflects the dynamic nature of the Public Service system. The Company will survey best practices in other jurisdictions when developing its methodology for these studies.

6. *Phase II Hybrid Resources ELCC Values.* The Company affirms that ELCC values for bid hybrid resources will be modeled using the sum of the ELCC values for each resource, subject to not exceeding the physical capacity of the resource (e.g., interconnection size, injection capability).

7. *Phase II Emergency Energy Costs.* Emergency Energy Costs are included in the EnCompass model if there are not enough resources available to meet energy requirements. In the model, the cost was set at a very high cost ($1 million/MWh) to ensure the model makes every effort to avoid emergency energy (which is synonymous with curtailed firm load). Emergency Energy costs occur only in rare instances; however, it does appear in some plans in very small amounts. To ensure large swings in plan costs are not created by these small amounts, for purposes of determining net present value ("NPV"), these $1 million costs were replaced in post-processing with more reasonable values of $2,000/MWh, escalating at 2 percent. For purposes of this Settlement Agreement, the Settling Parties agree that the $1 million/MWh level will be adjusted to $50,000/MWh, and the Company will follow the modeling process set forth in Volume II (Attachment AKJ-2) accordingly. If this value results in substantial amounts of Emergency Energy in the model results, the Company will consult with the Independent Evaluator ("IE") to determine an appropriate value to use to eliminate Emergency Energy costs from the modeled runs.

8. *Phase II Comanche 3 Historic Operations and Maintenance ("O&M") Costs.* The Company agrees that in this ERP Phase II modeling, the historical O&M costs for Comanche 3 will be utilized, as proposed by Staff and supported by the record evidence

in this proceeding.[6] Other O&M costs will be modeled as presented in the Company's Direct Testimony and the parties agree to retain their rights in future ERPs to support any O&M position they deem prudent.

9. *Phase II Loads and Resources Table Update.* The Company agrees to update its Load and Resources table for the Phase II process consistent with the Rebuttal Testimony of Jon Landrum.[7]

10. *Phase II Gas Price Forecast Update.* The Company agrees it will update its gas price forecast for the Phase II process consistent with the Rebuttal Testimony of Jon Landrum.[8]

11. *Phase II Changed Circumstances.* The Company agrees to make clear, as part of the RFP announcement, how it intends to handle any changes in circumstances that could significantly impact portfolio selection comparative costs. For example, an extension or change in eligibility of the Federal Production Tax Credit / Investment Tax Credit ("PTC/ITC") program would need to be addressed. If PTC or ITC eligibility or other elements are changed by law, the Company will re-convene the Settling Parties to attempt to make conforming changes to the model PPAs unanimously and take any other actions made necessary by the change in law. If unanimity cannot be achieved, the Company will bring such changes to the Commission for resolution.

[6] Staff's position is to model Comanche 3's variable O&M at $2.20/MWh and its fixed costs at $24.076 million per year in Phase II modeling. Hearing Exhibit 2700C, Answer Testimony of Dr. Steven Dahlke, pages 36-37.

[7] Hearing Exhibit 124, Rebuttal Testimony of Jon T. Landrum, at page 119.

[8] Hearing Exhibit 124, Rebuttal Testimony of Jon T. Landrum, at page 119.

12. *Phase II ERP Transmission Costs.* The Company agrees that in Phase II modeling the ERP portfolio analyses will include the ERP transmission costs estimated by the Company in the Power Pathway Proceeding, No. 21A-0096E, updated for the higher SCC value utilized in Phase II modeling as explained in the Rebuttal Testimony of Jon Landrum.[9] In addition, the Company will use the final approved estimate in Proceeding No. 21A-0096E (if available) for the Pathway Project for all CEP portfolio analyses.

13. *Phase II Transmission Upgrades.* The Company agrees that the ERP Phase II modeling will include approximately $400-500 million of the Company's estimate of future costs associated with needed Denver Metro Area network upgrades and reactive/voltage support and grid strengthening. This value will be refined to reflect Phase II portfolios developed and presented in the 120-Day Report.[10]

II. Phase II Portfolios and 120-Day Report Contents

The Settling Parties agree to the following terms for Phase II portfolios and 120-Day Report contents:

14. *Phase II Portfolio Framework.* The Company will model Phase II bid portfolios for its 120-Day Report as set forth in Attachment 1.

15. *Phase II Single Resource Acquisition Period ("RAP") and 2029 and 2030 Resource Acquisitions.* The Settling Parties agree that the RAP should be a single RAP for resource acquisition, consistent with the statute, from 2021 through 2030. The

[9] Hearing Exhibit 124, Rebuttal Testimony of Jon T. Landrum, at pages 54-55.

[10] This value reflects the Company's current estimate and does not bind any Settling Party in any future proceeding.

Company will issue a single RFP for purposes of soliciting resources to fill RAP needs. However, the Company agrees in this 2021 ERP & CEP not to accept bids for and not to acquire resources with in-service dates after December 31, 2028. The final, approved plan in Phase II of this ERP may include new, generic resources in 2029 and 2030; however, in any future solicitations after this 2021 ERP & CEP, there shall not be any presumption that any generic resources in this ERP should be acquired. All 2029 and 2030 resource needs identified will be filled through the Pueblo Just Transition Plan solicitation, which will utilize a Resource Acquisition Period through end of year 2031. The Settling Parties agree that an approved Clean Energy Plan that meets or exceeds the emissions reduction requirements of § 25-7-105(1)(e)(VIII)(C), C.R.S., even while including generic resource additions through December 31, 2030, may obtain the “safe harbor” provided for under this statutory provision. Upon request of the Company, each Settling Party shall sign a written statement affirming the Settling Party’s position that a Clean Energy Plan approved by the Commission in its Phase II Decision that includes generic resources for 2029 and 2030 qualifies for the “safe harbor” if the Commission approves the Plan and the Division verifies that the Clean Energy Plan meets or exceeds the emissions reduction requirements of § 25-7-105(1)(e)(VIII)(C), C.R.S. The Company may introduce such written statements as evidence in any relevant proceeding before the AQCC, Commission, or a court of competent jurisdiction. The Settling Parties shall not make any statements or filings of any nature regarding the Clean Energy Plan failing to meet or exceed the emissions reduction requirements of § 25-7-105(1)(e)(VIII)(C), C.R.S. or failing to qualify for the “safe harbor” as a result of the inclusion of generic resources for 2029 and 2030. In the event of any legal challenge to the Division's verification of this Clean Energy Plan as approved by the Commission in its Phase II Decision, and/or the application of the safe harbor to the Clean Energy Plan based on the inclusion of generic resources in the final two years of the RAP, then each Settling Party:

(1) agrees that the Company may represent in any such proceeding that it is each Settling Party's position that a Clean Energy Plan that includes generic resources for 2029 and 2030 qualifies for the "safe harbor" if the Commission (i.e., the PUC) approves the Clean Energy Plan and the Division verifies that the Clean Energy Plan meets or exceeds the emissions reduction requirements of § 25-7-105(1)(e)(VIII)(C), C.R.S.; and

(2) shall meet and confer with the Company regarding how the Settling Party, consistent with its resources and staffing, can appropriately support the Division's verification that the Commission-approved Clean Energy Plan that includes generic resources for 2029 and 2030 meets or exceeds the emissions reduction requirements of § 25-7-105(1)(e)(VIII)(C) and qualifies for the "safe harbor" and defend this Settlement Agreement.

16. *120-Day Report Emissions Reporting.* The Company will provide, in the 120-Day Report, modeled emissions as follows for Phase II portfolios:

i. Annual tons in 2030, 2035, 2040, 2045, and 2050;
ii. Cumulative and annual tons for 2021-2030; and
iii. Cumulative tons for 2031-2050.

With these settlement terms, the system is expected to operate in a manner that achieves, at a minimum, a 50 percent carbon dioxide emissions reduction from 2005 levels in 2024 and a 65 percent carbon dioxide emissions reduction from 2005 levels in 2027. These interim emissions expectations will not limit any potential resource acquisitions in the Phase II that could result in a higher carbon emissions reduction outcome. The Company is committed to exceeding these interim carbon dioxide emissions reduction targets where practicable, given the potential for increased emissions reductions as shown in Paragraph 39, depending upon bid receipt, project development, and in-servicing.[11] The Company will report the actual emissions achieved as compared to these interim emissions expectations by October 31 of the year following the emissions year being reported, consistent with § 25-7-105(1)(e)(VIII.5)(D), C.R.S. The emissions reported for purchased and owned generation will be consistent with reporting procedures required under the AQCC's Regulation 22, Part A Section IV. C.2 and consistent with the data and reporting principles of IV.C.1. Such data may be subject to confidentiality provisions as appropriate, and the Company will report this data through 2030.

17. In conjunction with the Interim-Year Emissions Reductions, the Company agrees to retire related renewable energy credits ("RECs") associated with any renewable energy used to serve customer load that is attributed in its Clean Energy Plan a GHG emissions rate of zero pounds per megawatt hour beginning in calendar year 2024. Such retirements will not include RECs generated by retail distributed generation where the retail customer retains the REC subject to and as provided for in § 25-7-105(1)(e)(VIII)(H),

[11] Settling parties note that the Company's modeling projects emissions reductions of 76 percent from 2005 levels in 2027, and 88 percent emissions reductions in 2031.

C.R.S.[12] Such retirements will also not include RECs conveyed by the Company to other entities pursuant to established contractual REC obligations, such as RECs conveyed pursuant to pre-existing wholesale and counterparty contractual commitments, and in recognition of such customers' treatment in the 2005 and 2030 carbon dioxide emissions baselines and reduction targets, respectively, under the Clean Energy Plan Guidance. The REC retirement process will follow a method similar to that which the Company uses to comply with the Renewable Energy Standard, with RECs retired by June 1 of the following year. For energy purchases used to serve customer load that is assigned a market-based, eGRID, or system emissions rate that reflects the use of renewable energy, the Company will provide the energy mix reflected by the emission rate in its ERP annual reports to the extent information regarding the energy mix is available. The Company commits to make good-faith efforts in conjunction with interested parties to study solutions to best capture the levels of such renewable energy, and to consider whether and how associated retirements of RECs may be accomplished with appropriate regulatory approvals and cost recovery. The Company will report on progress in these efforts, to the Commission, in the annual ERP reports.

[12] § 25-7-105(1)(e)(VIII)(H), C.R.S, reads: "(H) IN VERIFYING CLEAN ENERGY PLANS OR A WHOLESALE GENERATION AND TRANSMISSION COOPERATIVE ELECTRIC RESOURCE PLAN SUBMITTED IN ACCORDANCE WITH SUBSECTION (1)(e)(VIII)(I) OF THIS SECTION, THE DIVISION SHALL PREVENT DOUBLE COUNTING OF EMISSION REDUCTIONS AMONG UTILITIES AND SHALL CONSIDER ELECTRICITY GENERATED BY RENEWABLE ENERGY RESOURCES AS HAVING ZERO GREENHOUSE GAS EMISSIONS ONLY IF:THE ELECTRICITY IS ACCOMPANIED BY ANY ASSOCIATED RENEWABLE ENERGY CREDIT, AND THE RENEWABLE ENERGY CREDIT IS RETIRED ON BEHALF OF THE UTILITY'S CUSTOMERS IN THE YEAR GENERATED; OR THE ELECTRICITY IS GENERATED BY RETAIL DISTRIBUTED GENERATION, AS DEFINED IN SECTIONS 40-2-124 (1)(a)(VIII) AND 40-2-127 (2)(b)(I)(A) AND (2)(b)(I)(B) AND THE RETAIL CUSTOMER RETAINS THE RENEWABLE ENERGY CREDIT AS PART OF A VOLUNTARY RENEWABLE ENERGY PROGRAM."

18. *120-Day Report Indicative Customer Bill Impacts.* The Company will provide, in the 120-Day Report, updated indicative forecasted customer bill impacts.

19. *120-Day Report Disproportionately Impacted Communities Resource Mapping.* The Company will map bids included in a portfolio in the 120-Day Report against either the Colorado Department of Public Health and Environment's ("CDPHE") best available mapping of disproportionately impacted communities, or similar mapping approved by the Commission such that the Commission can consider the impacts of bids that are proposed in disproportionately impacted communities when evaluating Phase II portfolios.

20. *120-Day Report Heat Maps.* The Company will include separate heat map graphics for the Preferred Portfolio in the 120-Day Report. Each graphic will be presented as modeled data for each year in the RAP on an average hour by month basis ("24 x 12" basis):

i. Modeled average CO_2 emissions (lb/kWh or similar intensity metric);
ii. Modeled demand net of renewables (MW);
iii. Modeled curtailment of solar (MWH); and
iv. Modeled curtailment of wind (MWH).

21. *Pre-Phase II Curtailment Discussions.* The Company agrees to collaborate with the Staff, UCA, CIEA, and Interwest between Phase I and Phase II to facilitate improvements on clarity of information regarding specificity for curtailment. This will include incorporation of a modeling approach to transparently capture the cost impacts of curtailments (compensable curtailment and any associated payment for Production Tax

Credits) for purposes of the Phase II modeling and portfolio development process, such that the Commission can consider such impacts in its Phase II Decision approving a final resource plan. Accordingly, in order to ensure transparency in the potential costs of curtailment (e.g., lost-PTCs and energy payments), in the Phase II process, the Company shall model all renewable energy with PTC eligibility as follows:

- For contract-based assets: Embed the annual cost of the project based on full production as provided for in the bid or contract as a fixed cost (e.g., a $15/MWh bid price * Annual MWh projected).
- For Company-owned assets: Embed the annual fixed cost of the project based on the fixed cost revenue requirement associated with the capital investment.
- For both Company-owned and contract-based assets: Gross up the annual fixed cost for the first 10 years of the project by the value of the PTC assuming 100% curtailment (e.g., Annual MWh projected * PTC price).
- When the model dispatches the wind energy resource, a negative value for the price of the PTC is the dispatch energy cost, this would result in the following:
    - Years 1-10 of PTC eligible resource life: Dispatch Energy Cost = -PTC/(1-TaxRate)
    - Years 11+: Dispatch Energy Cost = 0
    - For the first ten years, the negative energy cost would offset/reverse the PTC gross up included in the first step for every MWh delivered to the system. If there were zero curtailment in a year, the offset would entirely reverse the gross up costs, resulting in an effective cost of the resource that is solely the bid price for a PPA and the revenue requirement for a Company asset.
- The methodology and formula above would incentivize the model to dispatch the renewable energy in a way that maximizes the utilization of the PTC and optimizes around the annual cost of the asset and the remaining MWh generated will be appropriately priced for the customers.

22. *Phase II No New Natural Gas Build Portfolio Presentation Parameters.* For the No New Natural Gas Build Portfolio set forth in Attachment 1, the Company will present this portfolio unless: (1) it is not technically feasible such that the EnCompass

model cannot build such a portfolio; or (2) the modeled portfolio fails the Company's reliability check. To the extent EnCompass is unable to build a portfolio, the Company shall provide such notice in the 120-Day Report. To the extent EnCompass is able to build a portfolio and the portfolio fails the reliability check, the Company will provide a detailed explanation in the 120-Day Report with regard to why the portfolio failed the reliability check. This portfolio will rely solely on any offered life extension and purchase power agreement ("PPA") extension gas proposals to the extent gas is selected as part of the portfolio, with new natural gas units excluded in the construction of the portfolio.

23. *Phase II Natural Gas Considerations.* The Company will re-bid any existing gas units that are scheduled for retirement in the RAP so long as the unit does not have to be retired pursuant to the Colorado State Implementation Plan under the Clean Air Act and is reasonably expected to perform in a manner that can balance the Company's system. This evaluation will be based on whether any re-bid gas unit, with additional capital investment and O&M necessary to life extend the unit: (1) has the flexibility necessary to assist in the integration of the increasing levels of variable generation that the Company expects as part of this 2021 ERP & CEP; and (2) assists in maintaining a reliable system. Furthermore, the Company will retain requirements for new natural gas generation bids proposed as part of its Direct Case (e.g., hydrogen capability).[13] Additionally, the Company will ensure the final contract terms for any hydrogen-capable resource includes the option for hydrogen, as bid, including the unique bidder proposed model PPA terms and conditions associated with the hydrogen option.

[13] Hearing Exhibit 104, Direct Testimony of James F. Hill, pages 74-75.

24. *New Natural Gas Asset Modeling Lives.* For Phase II modeling purposes, the Company will limit the depreciation lives for new natural gas assets to 25 years. For any new natural gas assets included in a final approved resource plan, the Company will address the depreciable life for such assets for ratemaking purposes through an appropriate future depreciation study.

25. *No Phase II "Round Trip Modeling."* The Company will not perform "round trip modeling" as proposed by UCA witness Dr. Milligan.[14]

III. <u>Modeling and Process Regarding Just Transition Plans</u>

The Settling Parties agree to the following terms for modeling and future process regarding Just Transition Plans:

26. *Just Transition Plan Cost Modeling.* The Company shall model just transition impacts (i.e., the potential future costs of both workforce transition plans and community assistance plans), consistent with the Company's Direct Case by utilizing an escalating property tax-based proxy value that runs until the earlier of (1) a unit's original retirement date (for all units other than Comanche 3); or (2) December 31, 2040 (in the case of Comanche 3). The final community assistance plan costs will be determined in future filings, inclusive of the provisions in this Settlement Agreement. The Settling Parties agree to and request the Commission adopt the following process for Just Transition Plans:

- *Step 1.* The Commission issues a Phase I Decision determining the accelerated retirement dates and operational treatment for all remaining coal units: Craig 2, Hayden 1, Hayden 2, Pawnee, and Comanche 3.

[14] Hearing Exhibit 502, Answer Testimony of Dr. Michael Milligan, page 24.

- *Step 2.* As part of the Phase I Decision, the Commission directs the Company on how to model the costs of a Just Transition Plan for any unit subject to an accelerated retirement. The Just Transition Plan cost estimate for modeling purposes will include two components: (1) the estimated cost of the updated Workforce Transition Plan; and (2) the estimated cost of the community assistance aspect of a Just Transition Plan. The estimated cost of the community assistance aspect will be equal to projected lost property tax revenues for six years following retirement or conversion for Hayden 1 and Hayden 2, and Pawnee, respectively, and ten years for Comanche 3 (i.e., from January 1, 2031 through December 31, 2040). The Company will apply this treatment to Hayden 1 and Hayden 2, Pawnee, and Comanche 3, consistent with the plant-specific terms below.
- *Step 3.* The Commission approves a final portfolio in the Phase II Decision with the estimated costs of the Just Transition Plan included in the cost estimate of the plan. Any investment and corresponding property tax revenue in an affected community will serve as an offset against the community assistance plan costs for purposes of these estimates. The Company agrees to reporting on Just Transition Plan elements every two years prior to the closure of a facility, and annually after the closure of a facility, until the period of community assistance concludes (e.g., 2040 for Comanche 3-related Just Transition elements).
- *Step 4.* The Company makes a follow-on, post-Phase II Decision filing for updated Just Transition Plans for each affected area where the Company is the operator of the affected coal plant and the plant is subject to a comprehensive or partial accelerated retirement (i.e., Hayden, Pawnee and Comanche) under this 2021 ERP & CEP. Just Transition Plan filings will include Workforce Transition Plan costs, community assistance costs, and any offsets to community assistance costs due to investments in the relevant community. This filing will include a proposal for a cost recovery mechanism (if not already addressed in a rate case) for any Just Transition Plan costs, and these plans could continue to be iterated through future ERP cycles as retirement dates get closer in time if their retirement is outside of this RAP.

IV. <u>Coal Action Plan</u>

The Settling Parties agree to the following Coal Action Plan:

A. Craig

27. Craig 2 will retire in 2028. The Settling Parties request that the Company receive approval to recover costs of Craig 2 pursuant to a determination to be made in

the Commission's Phase II Decision in this proceeding. In the Phase II process, the Company will model, for consideration by the Commission in the Phase II process, two approaches to recovering the remaining net book value and future decommissioning costs: (1) a hybrid of 50% accelerated depreciation and 50% regulatory asset with a full return and an eight-year amortization; and (2) the regulatory asset approach with a full return[15] and an eight-year amortization period, explained in more detail in Paragraph 60. The amount to be amortized, inclusive of the net book value and future decommissioning costs, is estimated to be $27.4 million.[16] Any cost recovery for Craig 2 shall be excluded from any Clean Energy Plan Revenue ("CEPR") rider calculation pursuant to § 40-2-125.5(5)(a), C.R.S.

B. Hayden

28. Hayden 1 will retire in 2028 and Hayden 2 will retire in 2027. The Settling Parties request that the Company receive approval to recover costs of Hayden 1 and Hayden 2 pursuant to a determination to be made in the Commission's Phase II Decision in this proceeding. In the Phase II process, the Company will model, for consideration by the Commission in the Phase II process, two approaches to recovering the remaining net book value and future decommissioning costs: (1) a hybrid of 50% accelerated depreciation and 50% regulatory asset with a full return and an eight-year amortization; and (2) the regulatory asset approach with a full return and an eight-year amortization period, as explained in more detail in Paragraph 60. The amount to be amortized,

[15] "Full return" in this document means full return of and on at the Company's weighted average cost of capital.
[16] The Company will update these numbers in the Phase II modeling to reflect decisions and analysis in Proceeding No. 21AL-0317E.

inclusive of the net book value and future decommissioning costs, is estimated to be $22.2 million (Hayden 1) and $55.4 million (Hayden 2).[17] Any cost recovery for Hayden 1 and Hayden 2 shall be excluded from any CEPR rider calculation pursuant to § 40-2-125.5(5)(a), C.R.S. The Company will file its updated Just Transition Plan for Hayden within 120 days of the final Phase II Decision in this proceeding.

29. The Company will model the Just Transition Plan costs for Hayden 1 and Hayden 2 consistent with the agreed upon modeling approach for Just Transition Plans. Any investment at Hayden Station or within Routt County will offset any total Just Transition Plan costs, and Just Transition Plan costs are recoverable pursuant to § 40-2-125.5(4)(a)(VII), C.R.S.

C. Pawnee

30. The Settling Parties agree that Pawnee will not be subject to an accelerated retirement. The Settling Parties agree that Pawnee will be converted to natural gas no later than January 1, 2026, to be effectuated through a future Certificate of Public Convenience and Necessity ("CPCN") filing as set forth below. The Company will recover the costs for the retirement of the coal-related portions of Pawnee prior to conversion through a regulatory asset approach with a full return utilizing an eight-year amortization period. The amount to be amortized, inclusive of the coal-related portions of Pawnee prior to conversion, is estimated to be $179.1 million.[18]

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[17] The Company will update these numbers in the Phase II modeling to reflect decisions and analysis in Proceeding No. 21AL-0317E.

[18] The Company will update these numbers in the Phase II modeling to reflect decisions and analysis in Proceeding No. 21AL-0317E.

31. The Company will file a CPCN within 90 days of a final Phase I decision in this proceeding. The CPCN will be a limited-scope CPCN,[19] focused solely on conversion costs and without analysis of alternatives, given it is a follow-on CPCN to an approved resource plan. The Company will discuss and continue to evaluate potential future hydrogen blending options at the site. The Company will provide updated analysis of this potential, including technical potential and cost estimates, in each of its next two ERPs.

32. Any investment at Pawnee Station or within Morgan County will offset any total Just Transition Plan costs. The Company will file an updated Just Transition Plan for Pawnee, and Just Transition Plan costs are recoverable pursuant to § 40-2-125.5(4)(a)(VII), C.R.S.

D. Comanche 3 Overall Approach

The Settling Parties agree to the following regarding Comanche 3 retirement:

33. Comanche 3 will retire by January 1, 2031.

34. Comanche 3 will be subject to operational limitations as described in Section IV.E. below.

35. The Company will file a financing order application pursuant to § 40-41-101, et. seq., the Colorado Energy Impact Bond Act, prior to the securitization of Comanche 3. The Company's estimate of the amount to be securitized, i.e., the bond size, is approximately $732 million (net book value of $690 million, $32 million in removal costs, and assuming $10 million in issuance costs). This Settlement Agreement does not bind

[19] This "limited-scope" CPCN is consistent with similar CPCN approaches utilized for the implementation of Clean Air-Clean Jobs Act and Colorado Energy Plan actions, respectively.

parties to supporting securitization as the future cost recovery method for Comanche 3, provided that parties agree the remaining book value and decommissioning costs of Comanche 3 determined to be prudent at the time of retirement, will be fully recovered, regardless of cost recovery methodology (e.g., securitization or regulatory asset). If a regulatory asset is approved for the recovery of remaining plant balances of Comanche 3, the Settling Parties agree the Company will utilize a cost of debt for the carrying cost associated with the regulatory asset.

E. Comanche 3 Early Reduced Operations

The Settling Parties agree on the approach to Comanche 3 early reduced operations set forth in this section. The Company shall continue to look for opportunities to reduce minimum up and down times of Comanche 3. The Company agrees to commence early limited operations and/or operational restrictions on Comanche 3 as follows:

36. Beginning in the summer of 2022, the Company will utilize a SCC value in the dispatch or commitment of resources in the Public Service system after obtaining any Federal Energy Regulatory Commission ("FERC") approvals necessary to do so.[20] The Company will continue to utilize the SCC in the dispatch or commitment of resources in the Public Service system until it enters an organized market structure of any kind, including, without limitation, an energy imbalance market. During its participation in any organized market structure, the Company will utilize a carbon value in the dispatch of its

[20] The Company agrees to make any necessary filings with FERC within 30 days of final Commission approval of this Settlement Agreement. The Company agrees to implement this provision within 5 days of receiving FERC approval but no earlier than June 1, 2022.

system consistent with the rules in effect for the organized market structure. This applies whether the market structure is an energy imbalance market, energy imbalance market with a day-ahead market component (e.g., Extended Day-Ahead Market or "EDAM"), a Regional Transmission Organization ("RTO"), or another organized market structure.

37. In addition to the use of the SCC value in the dispatch or commitment of resources in the Public Service consistent with the discussion above, the Company will operate Comanche 3 as follows:

i. Beginning with the utilization of SCC in the dispatch of Summer 2022, any must-run requirements will be removed other than when required for transmission or reliability constraints, and economic commitment will be implemented.

ii. Beginning on January 1, 2025, the Company will operate Comanche 3 based on a target annual capacity factor of 50 percent, and a maximum annual capacity factor of 60 percent.[21]

iii. Beginning on January 1, 2027, the Company will operate Comanche 3 based on a maximum annual capacity factor of 50 percent.

iv. Beginning on January 1, 2029, the Company will operate Comanche 3 based on a maximum annual capacity factor of 33 percent.

38. In the case of an extraordinary event(s) that the Company exceeds the maximum annual capacity factor for a given year, the Company will make a filing in its Electric Commodity Adjustment ("ECA") annual prudence review to explain the circumstances that led to the need to exceed the maximum annual capacity factor.

[21] The ECA reporting provisions shall apply for years 2025 and 2026 only to the extent a 60 percent maximum annual capacity factor is exceeded.

39. The estimated incremental emissions reductions and incremental costs to customers for the proposal for years 2022 through 2030 based on the base gas forecast is as follows:[22]

Carbon (Tons)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Original Settlement, SCC 9-SA (Dec 1, 2021)	16,534,119	13,541,865	10,485,440	14,163,089	11,846,584	7,222,265	6,542,996	6,165,625	4,783,065	4,108,882
Revised Settlement, SCC 10-RSA (April, 2022)	16,534,119	13,541,865	10,485,440	14,163,089	11,853,429	7,192,664	6,505,306	5,964,483	4,555,312	4,177,323
Delta	-	-	-	-	6,845	(29,601)	(37,691)	(201,142)	(227,753)	68,441
Total										(420,900)
Reduction from 2005 Levels	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Original Settlement, SCC 9-SA (Dec 1, 2021)	-39%	-50%	-62%	-48%	-57%	-74%	-76%	-77%	-82%	-85%
Revised Settlement, SCC 10-RSA (April, 2022)	-39%	-50%	-62%	-48%	-57%	-74%	-76%	-78%	-83%	-85%
Delta	0%	0%	0%	0%	0%	0%	0%	-1%	-1%	0%
Utility Costs ($million) - 60% Ownership	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Original Settlement, SCC 9-SA (Dec 1, 2021)	$1,772	$1,780	$1,839	$1,901	$1,988	$2,093	$2,169	$2,235	$2,368	$2,512
Revised Settlement, SCC 10-RSA (April, 2022)	$1,772	$1,780	$1,839	$1,901	$1,984	$2,075	$2,155	$2,252	$2,385	$2,497
Delta	$0	$0	$0	$0	-$4	-$18	-$14	$17	$17	-$15
CO2 Costs ($million)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Original Settlement, SCC 9-SA (Dec 1, 2021)	$795	$680	$549	$774	$675	$429	$405	$397	$314	$281
Revised Settlement, SCC 10-RSA (April, 2022)	$795	$680	$549	$774	$675	$427	$402	$384	$299	$286
Delta	$0	$0	$0	$0	$0	-$2	-$2	-$13	-$15	$5
Total Cost ($million)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Original Settlement, SCC 9-SA (Dec 1, 2021)	$2,566	$2,459	$2,388	$2,675	$2,663	$2,521	$2,574	$2,632	$2,682	$2,793
Revised Settlement, SCC 10-RSA (April, 2022)	$2,566	$2,459	$2,388	$2,675	$2,659	$2,502	$2,557	$2,636	$2,684	$2,783
Delta	$0	$0	$0	$0	-$4	-$19	-$16	$4	$2	-$10

40. The cumulative reductions will be reported in the Company's annual ERP update as an annual million short tons ("MST") value and compared to the adjusted baseline developed in the Clean Energy Plan Guidance and appendices included in the Company's Direct Case as Attachment LWQ-1.[23]

41. Procuring adequate flexible, dispatchable generation is imperative to allow for the early reduced operations set forth in this proposal and a reliable system.

F. Comanche 3 Updated Just Transition Plan

42. The Company will model the Just Transition Plan costs for Comanche 3 consistent with the agreed upon modeling approach for Just Transition Plans. Any

[22] The Settling Parties understand the data provided in this estimate is for informational purposes only, and does not create new requirements in addition to the dispatch and capacity factor requirements put forth in this Settlement Agreement.

[23] Hearing Exhibit 108, Direct Testimony of Lauren W. Quillian, Attachment LWQ-1.

replacement generation sited at Comanche Station or within Pueblo County will offset any total Just Transition Plan costs, and Just Transition Plan costs are recoverable pursuant to § 40-2-125.5(4)(a)(VII), C.R.S. The Company commits to make payments to Pueblo County annually from 2031 through 2040 (and allocated by the treasurer's office accordingly) in the amount of the projected lost property tax revenues for those years, unless offset by property tax revenues from generation or transmission infrastructure sited at Comanche Station or within Pueblo County.

43. Through its Just Transition Plan filing for Comanche 3, the Company will conduct a standalone Just Transition Plan competitive solicitation for the replacement of the energy and capacity associated with Comanche 3. This process will occur on a standalone basis in an effort to ensure the Pueblo community and benefits to the community are the focus of the replacement portfolio, simultaneously seeking just transition benefits and the procurement of innovative technologies to help the Company progress towards a carbon-free future. With the exception of updating generic resource assumptions, the ELCC Study, the Planning Reserve Margin Study, DSM strategic issues assumptions,[24] Renewable Energy Plan assumptions, the PacifiCorp East transmission assumptions detailed in paragraph 66, the inclusion of any transmission projects with filed or approved CPCNs for the Company, an updated assessment of the existing transmission system, and regional market-related assumptions based on updated data and known circumstances, the all-source competitive solicitation will utilize the modeling

[24] Parties expect this will include load management, demand response, energy efficiency, beneficial electrification, and transportation electrification.

inputs and assumptions approved in the most recent Phase I ERP unless good cause is shown to modify the modeling inputs and assumptions. To the extent that any procedures or aspects of the Pueblo Just Transition Plan filing are not addressed by the Settlement Agreement, the application proceeding shall be treated as an Interim ERP under Rule 3603(a) and shall otherwise comply with applicable ERP Rules for the first and second phases of the process. As part of the first phase of its Just Transition Plan filing, the Company will obtain approval of any modeling inputs and assumptions that are changed from the most recent ERP, followed by a competitive solicitation. The Company will present any proposed changes through its Direct Testimony, intervenors will have an opportunity to respond through Answer Testimony, and the Company and intervenors may reply through Rebuttal/Cross-Answer Testimony. The Settling Parties request that the Commission issue a decision on the first phase of the Just Transition Plan filing, on an expedited basis to the extent practicable, prior to the commencement of the Just Transition Plan competitive solicitation.

44. Based upon the bids received in the competitive solicitation, the Company will evaluate and present, for Commission consideration, different Pueblo Just Transition Portfolios, each of which can include resources with varying in-service dates and address the retirement date for Comanche 3, which will be no later than January 1, 2031. The Settling Parties request that the Commission approve a cost-effective Pueblo Just Transition Portfolio after evaluating the cost impacts of the different portfolios, the progress the portfolios make towards the Company's overall contributions to meeting the statewide emissions reductions goals of House Bill 19-1261, and the just transition-

related benefits and other impacts that the portfolios provide to the Pueblo community and the State of Colorado. The Company will utilize a 90 percent emission reduction target in 2033 from 2005 levels (adjusted baseline in CEP Guidance) in the development of the Pueblo Just Transition portfolios; provided, however, that the Company will present portfolios that do not reach the target and an informational least-cost plan to compare the cost effectiveness of the 90 percent emission reduction portfolios. The Company may advocate for any of the portfolios developed.

45. The Company will own, at a minimum, $690 million in capital investment or 500 MW of accredited capacity, whichever is triggered first, for resources necessary to replace the accredited capacity of Comanche 3, provided that a showing of resource need is made in the first phase of the Comanche 3 Just Transition Plan filing and any final approved plan in the second phase must be deemed a cost-effective resource plan consistent with Rule 3601 and Rule 3617 after a full consideration of the just transition and emissions reduction benefits of the plan. The Just Transition Plan solicitation will also utilize a utility ownership target of 50 percent for energy and capacity acquired that is in excess of the $690 million investment or 500 MW accredited capacity minimum, and provided that the final approved resource plan is cost-effective as set forth above.[25] The Comanche 3 Just Transition Plan will be filed no later than June 1, 2024. The solicitation will accept build-own-transfer ("BOT") and asset-transfer proposals for consideration, which will count towards the Company's ownership target. Bids featuring joint ventures

[25] The Pueblo Just Transition Plan Solicitation will utilize an all-source competitive solicitation, and the Settling Parties agree that a portfolio development framework will be adjudicated in the Phase I of the Pueblo Just Transition Plan process.

or partnerships between independent power producers/developers and the Company will also be accepted. To the extent a joint venture or partnership bid is approved as part of the Pueblo Just Transition Portfolio, only the Company's contribution to the project from a capital investment perspective will be counted towards the $690 million investment minimum. It is the expectation of the Settling Parties that the total cost of the energy and capacity necessary to replace the accredited capacity of Comanche 3 will substantially exceed the $690 million minimum.

46. Holy Cross, in its sole discretion, shall have the option to select one or more replacement resources owned by or contracted to Holy Cross and interconnected with the Integrated Transmission System (as that term is defined in the PSCo-HCE Transmission Integration and Equalization Agreement) that will be provided appropriate transmission access, capacity accreditation entitlement and equivalent capacity credit associated with the Facility under the PSCo-HCE Power Supply Agreement, to the extent it is still in effect, by the Company following the early retirement of the Facility in an amount not to exceed Holy Cross' existing volumes from the Facility as of the date of this agreement. These may include projects selected by Holy Cross through the Pueblo Just Transition Resource Solicitation after the portfolio necessary to serve the Company's retail customers has been selected.

47. The approved Pueblo Just Transition Portfolio will be deemed by the Settling Parties to satisfy any obligations of the Company pursuant to § 40-2-125.5(4)(a)(VII), C.R.S. as it relates to the accelerated retirement of Comanche 3.

48. The Company will conduct a study at an amount not to exceed $2 million to evaluate a variety of potential low-emission or carbon-free dispatchable resource options located at the site of Comanche Station or within Pueblo County that can contribute to the Company's continued efforts to reduce emissions.

49. To the extent there is an over-collected balance in the CEPR account at the time that the CEPR concludes (2030), the Company will apply any over-collected balance towards the undepreciated balance of the coal-related portions of Pawnee. Further, to the extent there is any remaining balance after application to Pawnee, the Company will apply it to the remaining net book value and future decommissioning costs of Comanche 3. In addition, the Company will commence CEPR collections in 2023 after making an appropriate advice letter filing.

V. Performance Incentive Mechanism

The Settling Parties agree to the following terms regarding the performance incentive mechanism ("PIM"):

50. The Settling Parties agree that the Company will conduct a stakeholder process to develop appropriate PIM(s) for the emissions reductions (volume and timeliness) associated with the Clean Energy Plan, and any such PIM must consider appropriate treatment, to the extent applicable, of curtailed energy from Company-owned and IPP-owned facilities. The Company's proposal as well as the alternative proposals and comments of the parties in this proceeding will be given consideration in developing a PIM for Commission consideration. While a consensus proposal is the goal, it is not required. It would be helpful for the Commission in its decision approving the Settlement

Agreement to identify any parameters with respect to the contested issues it would like to see addressed in the PIM.

51. The PIM process for Settling Parties is as follows:

i. The stakeholder process will be initiated by the Company 15 days after the filing of the 120-Day Report.

ii. The Company will file a PIM proposal with the Commission 60 days after the filing of the 120-Day Report with supporting testimony.

iii. A 30-day comment period will commence upon the PIM proposal filing for responses to the PIM proposal for any interested ERP parties (Proceeding No. 21A-0141E) that would like to comment on the PIM proposal:

1. If no protests are filed, the Settling Parties request Commission approval within 60 days after filing of PIM proposal.

2. If protested, the Settling Parties request the Commission conduct a limited and expedited hearing within 30 days of comment deadline, and following the hearing, the Settling Parties request the Commission issue a decision on any PIM within 30 days of hearing. It is anticipated that this decision will follow any Phase II decision.

iv. There will be no discovery process regarding the PIM proposal.

VI. Revisions to Model Contract Terms

The Settling Parties agree to the following regarding revisions to Model PPA terms:

52. *Compensable Curtailments.* The Company agrees to modify its position to compensate for Production Tax Credits ("PTCs") in the instance of an otherwise compensable curtailment to remove the non-compensable PTC provision from the Model PPAs and provides revised language reflecting the treatment of PTCs for otherwise

compensable curtailments as reflected in the attached Revised Model Renewable PPA to this Updated Settlement Agreement (Attachment 3).[26]

53. *Availability and Committed Energy Requirements for Wind Projects*. For Wind PPAs, the Settling Parties agree that the Company will establish availability and committed energy requirements as reflected in the attached Revised Model Renewable PPA to this Updated Settlement Agreement (Attachment 3).

54. *Weather Adjustment Factor.* For solar PPAs, the Company will establish a Weather Adjustment Factor to apply to Section 8.4 and 12.1(A)10 of the PSCo Model Renewable PPA. Similar to Exhibit M – Methodology for Adjusting Committed Energy in the 2017 All Source RFP and 2019 ERP Amendment RFP, the Committed Solar Energy for the relevant Commercial Operation Year shall be multiplied by the ratio of the actual global horizontal irradiance for such Commercial Operation Year to the annual expected global horizontal irradiance for the Facility.[27] This revision is reflected in the attached Revised Model Renewable PPA to this Updated Settlement Agreement (Attachment 3).

55. *House Power.* The Company agrees that an independent power producer ("IPP") may self-generate House Power when located in service territory of other utilities provided that the host utility allows for such self-generation.

56. *Availability Requirements for Hybrid Solar Plus Storage Units.* Availability requirements for hybrid solar plus storage units should be based on a rolling 24-month period.

[26] Staff takes no position on Attachment 3 at this time.

[27] *See* Attachment 2 to this Settlement Agreement.

57. *Battery Storage and Hybrid Resources.* Battery storage and hybrid resources will contribute to resources available for Flex Reserves.

58. *Stakeholder Group Regarding Curtailment Processes.* The Company, Interwest members, CIEA members, COSSA members, and other interested Settling Parties will convene a stakeholder group to discuss curtailment expectations and utilization on the Public Service system and approaches to work through curtailment processes as the Company continues to transition to increasing levels of variable generation, as well as diversity benefits and ways to use the real time attributes of inverter-based resources for ancillary services to support grid reliability.

VII. <u>Other Items</u>

The Settling Parties agree to the following terms regarding other issues raised in this proceeding:

59. The Settling Parties agree that the CEPR rate impact will be determined in Phase II of this proceeding using the generic resources for 2029 and 2030. In addition, the Pueblo Just Transition acquisition will not revisit the rate impact and will not contain CEP versus ERP portfolios.

60. *Phase II Coal Plant Cost Recovery Modeling*. In the Phase II modeling, the Company will model a hybrid of 50% accelerated depreciation and 50% regulatory asset with a full return and an eight-year amortization cost recovery for Craig 2, Hayden 1, and Hayden 2 for each portfolio. In addition, the Company will model a regulatory asset with a full return and an eight-year amortization period for Craig 2, Hayden 1, and Hayden 2 for each portfolio. Cost recovery for Pawnee will be modeled with a full return and an

eight-year amortization period for each portfolio. The modeling will commence any regulatory asset on the retirement date of the relevant coal plant,[28] and the Company will keep cost recovery methodology consistent in each portfolio, i.e., either accelerated depreciation or regulatory asset, to avoid compounding the number of portfolios presented in the 120-Day Report. If the Commission approves accelerated depreciation as the cost recovery approach for Craig 2, Hayden 1, and Hayden 2 in its Phase II decision, the Settling Parties agree that the Company shall file a compliance advice letter to implement the accelerated depreciation within 14 days of a final Phase II Decision, which shall be effective on not less than two days' notice.

61. *Batteries and Other Energy Storage Bids Capable of Providing Energy and Regulation Services.* The Company will state in its Phase II bidding documents that it is interested in receiving bids for batteries and other energy storage technologies capable of providing both energy and regulation services. The RFP documents and Model PPAs will be modified, as necessary, prior to RFP release.

62. *City of Boulder Zero Emissions Community Portfolio Program*. The Company will work with the City of Boulder and other interested Parties, to develop a program design for the "Zero Emissions Community Portfolio Program" and, if agreement is reached on program design, the Company will present it to the Commission no later than June 2022.

[28] For Hayden 1 and Hayden 2, this date will be 2028 as that is the date of the last unit retirement at Hayden Station.

63. *Curtailment Analysis and Reporting.* The Company will provide analysis and reporting of curtailments. The Company will report to the Commission annually through its ECA annual prudence review filings.

64. *Bid In-Service Dates.* The Company will allow bids with in-service dates as early as 2023, provided bids are viable and construction timelines, if applicable, are reasonable.

65. *Next Electric Resource Plan.* The Company shall file its next electric resource plan under Rule 3601 no later than October 31, 2026. Notwithstanding the foregoing, the Company may present a request for variance to this deadline if future circumstances warrant a change, and Settling Parties reserve their rights to advocate for a different filing deadline based on circumstances in the future. The Settling Parties agree that a request of the Commission for any necessary waivers for this term shall be requested in the submittal of this agreement.

66. *Transmission Interconnection Expansion Study.* The Company will study expansions of transmission interconnection to the PacifiCorp system after this ERP. If a CPCN has been filed for any expansion of transmission interconnection to the PacifiCorp system ahead of either the Pueblo Just Transition Plan solicitation or the 2026 ERP Phase II competitive solicitation, the Company will model portfolios assuming the availability of any such project(s). Moreover, in each ERP contemplated in this Settlement Agreement, the Company agrees to treat any transmission project or projects with an approved or pending CPCN filed in Colorado as planned upgrades not yet in service for the purposes of determining overall transmission costs. The Company will enable bidders in each ERP

contemplated in this Settlement Agreement to select a point of interconnection ("POI") for the project subject to the CPCN.

67. *Tracking and Reporting CEP Incremental Costs.* The Company will establish a tracking and reporting mechanism for CEP incremental costs.

68. *Retirement of Renewable Energy Credits ("RECs").* Public Service will retire RECs associated with its renewable generation used in its approved CEP, in the year generated, including prior to 2030.

69. *Consideration of Best Value Employment Metrics ("BVEM").* The Company will include a multi-step process in the Phase II bid evaluation to ensure consideration by the Commission of BVEM under § 40-2-129(1)(a), C.R.S.:

i. The RFP will direct Bidders to include quantitative information with bids regarding: (1) the availability of training programs, including training through apprenticeship programs registered with the United States department of labor's office of apprenticeship or by state apprenticeship councils recognized by that office; (2) employment of Colorado labor as compared to importation of out-of-state workers; (3) long-term career opportunities; and (4) industry-standard wages, health care, and pension benefits. If the contracts for the project which is bid are not yet completed, the Bidders shall include the standards the Bidders include in their requests for proposals to be issued to subcontractors related to these elements. To the extent that quantitative information cannot be provided for any of these categories, bidders shall explain why as part of their bid package.

ii. A bid that incorporates a Project Labor Agreement ("PLA") will automatically be considered to meet threshold BVEM standards.

iii. The Company will conduct an initial screen of BVEM provided and disqualify bids that do not provide sufficient BVEM as set forth above as part of the bid package.

iv. The Company will retain a labor economist to assist in scoring bids for the BVEM provided, with the costs of the labor economist recovered through the ECA. The retained labor economist shall score the BVEM for all bids advanced to computer-based modeling. The labor economist shall be made available at the pre-bid conference to discuss major considerations related to BVEM evaluation.

As part of its 120-Day Report, the Company will provide a cumulative BVEM score for each portfolio presented as part of any Commission-approved portfolio development framework. The cumulative BVEM score will be considered by the Commission in its evaluation of bid portfolios, consistent with § 40-2-129(1)(a), C.R.S.

GENERAL PROVISIONS

70. Except as expressly set forth herein, nothing in this Settlement Agreement is intended to have precedential effect or bind the Settling Parties with respect to positions they may take in any other proceeding regarding any of the issues addressed in this Settlement Agreement. No Settling Party concedes the validity or correctness of any regulatory principle or methodology directly or indirectly incorporated in this Settlement Agreement. Furthermore, this Settlement Agreement does not constitute agreement, by any Settling Party, that any principle or methodology contained within or used to reach this Settlement Agreement may be applied to any situation other than the above-captioned proceeding, except as expressly set forth herein.

71. The Settling Parties agree the provisions of this Settlement Agreement, as well as the negotiation process undertaken to reach this Settlement Agreement, are just, reasonable, and consistent with and not contrary to the public interest, and should be approved and authorized by the Commission.

72. The discussions among the Settling Parties that produced this Settlement Agreement have been conducted in accordance with Rule 408 of the Colorado Rules of Evidence.

73. Nothing in this Settlement Agreement shall constitute a waiver by any Settling Party with respect to any matter not specifically addressed in this Settlement Agreement.

74. The Settling Parties agree to support, or not oppose, all aspects of the Settlement Agreement embodied in this document in any hearing conducted to determine

whether the Commission should approve this Settlement Agreement, and/or in any other hearing, proceeding, or judicial review relating to this Settlement Agreement or the implementation or enforcement of its terms and conditions. Each Settling Party also agrees that, except as expressly provided in this Settlement Agreement, it will take no formal action in any administrative or judicial proceeding that would have the effect, directly or indirectly, of contravening the provisions or purposes of this Settlement Agreement. However, except as expressly provided herein, each Settling Party expressly reserves the right to advocate positions different from those stated in this Settlement Agreement in any proceeding other than one necessary to obtain approval of, or to implement or enforce, this Settlement Agreement or its terms and conditions.

75. The Settling Parties do not believe any waiver or variance of Commission rules is required to effectuate this Settlement Agreement but agree jointly to apply to the Commission for a waiver of compliance with any requirements of the Commission's Rules and Regulations, if necessary, to permit all provisions of this Settlement Agreement to be approved, carried out, and effectuated.

76. This Settlement Agreement is an integrated agreement that may not be altered by the unilateral determination of any Settling Party. There are no terms, representations or agreements among the parties which are not set forth in this Settlement Agreement.

77. This Settlement Agreement shall not become effective until the Commission issues a final decision addressing the Settlement Agreement. In the event the Commission modifies this Settlement Agreement in a manner unacceptable to any

Settling Party, that Settling Party may withdraw from the Settlement Agreement and shall so notify the Commission and the other Settling Parties in writing within ten (10) days of the date of the Commission order. In the event a Settling Party exercises its right to withdraw from the Settlement Agreement, this Settlement Agreement shall be null and void and of no effect in this or any other proceeding.

78. There shall be no legal presumption that any specific Settling Party was the drafter of this Settlement Agreement.

79. This Settlement Agreement may be executed in counterparts, all of which when taken together shall constitute the entire Agreement with respect to the issues addressed by this Settlement Agreement. This Settlement Agreement may be executed and delivered electronically and the Settling Parties agree that such electronic execution and delivery, whether executed in counterparts or collectively, shall have the same force and effect as delivery of an original document with original signatures, and that each Settling Party may use such facsimile signatures as evidence of the execution and delivery of this Settlement Agreement by the Settling Parties to the same extent that an original signature could be used.

Dated this 24th day of November 2021.

Agreed on behalf of:

PUBLIC SERVICE COMPANY OF COLORADO

By: *<u>/s/ Alice K. Jackson</u>*
Alice K. Jackson
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Approved as to form:

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