BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 22A-0230E

IN THE MATTER OF THE APPLICATION OF BLACK HILLS COLORADO ELECTRIC, LLC FOR (1) APPROVAL OF ITS 2022 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN, AND (2) APPROVAL OF ITS 2023-2026 RENEWABLE ENERGY STANDARD COMPLIANCE PLAN

UNANIMOUS COMPREHENSIVE SETTLEMENT AGREEMENT

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INTRODUCTION

This Unanimous Comprehensive Settlement Agreement ("Settlement Agreement" or "Agreement") is entered into by Black Hills Colorado Electric, LLC d/b/a Black Hills Energy ("Black Hills" or the "Company"), Trial Staff of the Commission ("Staff"), the Office of the Utility Consumer Advocate ("UCA"), the Colorado Energy Office ("CEO"), the City of Pueblo, the Board of County Commissioners of Pueblo County ("Pueblo County"), Cañon City, Western Resource Advocates ("WRA"), the Colorado Independent Energy Association ("CIEA"), Interwest Energy Alliance ("Interwest"), Energy Outreach Colorado ("EOC"), and Walmart Inc. ("Walmart") (each a "Settling Party" and collectively the "Settling Parties"), pursuant to Rule 1408 of the Colorado Public Utilities Commission's ("Commission") Rules of Practice and Procedure, 4 CCR 723-1.

This Settlement Agreement is intended to resolve all issues which were or could have been raised by the Settling Parties in this Proceeding with respect to the Company's Verified Application ("Application") for approval of: (1) its 2022 Electric Resource Plan and Clean Energy Plan ("2022 ERP and CEP" or "Plan"), and (2) its 2023-2026 Renewable Energy Standard Compliance Plan ("RES Plan") (collectively, the "2022 ERP/CEP/RES Plan").

SETTLEMENT TERMS

The Settling Parties agree that the Commission should approve the Company's Application, subject to the following modifications and conditions:

I. Clean Energy Plan

A. CEP Requirements and Safe Harbor

1. The Settling Parties support Black Hills' voluntary election to make itself subject to § 40-2-125.5, C.R.S., and the requirement that Black Hills reduce its greenhouse gas emissions by at least 80 percent from 2005 levels by 2030. The Settling Parties agree that Black

Hills' 2022 ERP and CEP, as modified by this Settlement Agreement, are intended to comply with the State's CEP requirements set forth in Senate Bill ("SB") 19-236, § 40-2-125.5, C.R.S., and House Bill ("HB") 19-1261, §§ 25-7-102, -103, and -105, C.R.S. and that the Commission's Phase I decision should approve the Phase II modeling of portfolios that meet or exceed the emissions requirements of § 25-7-105(1)(e)(VIII)(C), C.R.S.

2. The Settling Parties agree that if, as a result of Phase II portfolio selection, the Company's Plan meets or exceeds the State's CEP emissions reduction requirements, does not adversely affect system reliability, comes at a reasonable cost to customers, and is found to be in the public interest by the Commission, then the Company's Plan is a Clean Energy Plan pursuant to §§ 40-2-125.5(3)-(4) and § 25-7-105(1)(e)(VIII)(C), C.R.S, and qualifies under the State's Safe Harbor provisions. The Settling Parties recognize that under § 25-7-105(1)(e)(VIII)(C), C.R.S., a utility with an approved CEP is not subject to additional greenhouse gas emissions reduction requirements by the Colorado Air Quality Control Commission pursuant to its implementation of § 25-7-105(1)(e), C.R.S.

3. The Settling Parties agree that the Commission should approve the Company's proposals as set forth in its Direct Case, as modified by its Rebuttal Case and the terms and conditions of this Settlement Agreement.

B. ***Modeling Assumptions***

4. The Settling Parties agree that the Commission should approve the Company's proposed modeling inputs and assumptions, as identified in pages 34-44 of Hearing Exhibit 102, Attachment MJH-1, and that those inputs and assumptions provide a reasonable and appropriate basis on which to conduct the Company's Phase II modeling, subject to the following:

4.1. Black Hills will update the modeling assumptions from its Direct Case for gas prices, large volume customer load forecast, demand-side management ("DSM"), and market prices. For DSM assumptions, the Company will update its DSM assumptions to align with the Company's most-recently approved DSM Plan from Proceeding No. 21A-0166E.

4.2. Black Hills agrees to update the Social Cost of Carbon ("SCC") and Social Cost of Methane ("SCM" and together with the SCC, "SC-GHG") values in the capacity expansion step of its Phase II modeling if the federal Interagency Working Group publishes updates to those values prior to the issuance of the Company's Phase II Request for Proposals ("RFP").

4.3. Black Hills agrees to update its Phase II modeling, model Power Purchase Agreements ("PPAs"), and, if necessary, RFP bid forms, to reflect the changes to tax credits from the Inflation Reduction Act ("IRA") and Infrastructure Investment and Jobs Act ("IIJA") affecting renewable energy and storage bids going forward. Black Hills agrees to make best efforts to maximize the receipt of any funds from this federal legislation, or other federal funds (as applicable) to reduce the costs and maximize the benefits of its CEP, and any system upgrades necessary to implement the CEP. These cost saving measures available through federal programs should be prioritized over non-economic factors.

C. Resource Acquisition and Utility Ownership Targets

5. Resource Acquisition Targets. The Settling Parties agree that the Commission should find the Company's proposed resource acquisition targets, as shown in the table below, to be reasonable and appropriate targets to base its Phase II modeling and portfolios around:

	Original CEP (MW)	Settlement CEP (MW)
Wind	149	100
Solar	258	200 – 250
Storage	50	50
Gas	0	0
Total Resource	457	~ 400
Emission Reductions	90%	80%
Utility Ownership (50%) inclusive of new or extended PPAs with affiliates	228	~ 200

5.1. Ultimately, the composition of the portfolios will be based on receipt of bids and the pricing offered. The quantities of each renewable generation resource displayed in the table above are illustrative, and represent Black Hills' estimates at this time. The values in the above table do not represent any mandatory level of each technology.

5.2. Black Hills commits to no new fossil-fueled acquisitions during this Resource Acquisition Period ("RAP").[1] For purposes of this Proceeding, "new fossil-fueled acquisitions" shall not include fast-start upgrade projects, hydrogen projects, or carbon sequestration projects, which may be bid into the Company's Phase II solicitation.

6. Utility Ownership Targets. The Settling Parties agree and acknowledge that the Company may propose to own up to a target of up to 50 percent of generation acquisitions that may be approved as part of this Proceeding, subject to the applicable terms and conditions set

[1] As explained in the Company's Direct Testimony, the Company utilized a nine-year RAP of 2022-2030, consistent with Rule 3602(n), and a 29-year planning period of 2022-2050, consistent with the requirements of Rule 3602(k), both of which also align with the planning horizon contemplated by SB 19-236. Hearing Exhibit 102, Direct Testimony of Michael J. Harrington, at 31:9-11.

forth herein concerning utility ownership. Company ownership may come from utility or affiliates as further detailed in § 40-2-125.5(5)(b), C.R.S.

7. To the extent a portfolio includes up to a 50 percent ownership target by the Company, 50 percent ownership shall only be allowed if it can be accomplished at reasonable cost, per Colorado law. Reasonable cost should be bound by the range of bids advanced to modeling.

D. Diesel Generation Units

8. The Settling Parties agree that the Commission should approve the Company's early retirement of the Pueblo diesel units (8 MW) in 2026.

8.1. The Settling Parties agree that the Commission should approve accelerated depreciation for these units, excluding the costs of decommissioning and removal, to be recovered through the Clean Energy Plan Rider ("CEPR") if a CEPR is approved in Phase II of this Proceeding, or through the Energy Cost Adjustment ("ECA") if a CEPR is not approved in Phase II of this Proceeding.

8.1.1. The Company will continue to depreciate costs for these units through base rates until the Company's next electric rate case proceeding. At that time, the Company will propose and Settling Parties will not oppose, removal of these assets from its electric rate base.

8.1.2. The Company currently estimates the net book value of these assets at that time will be $362,640, which is based on its cost estimate presented in its Direct Case, but revised to remove the level of decommissioning costs currently being recovered through Black Hills' Commission-approved depreciation rates. The Company will propose to true-up any remaining under- or over-depreciation in its next electric rate case, which Settling Parties will not oppose.

8.2. The Settling Parties agree that the Commission should find that these units may be retired without the need for any additional future regulatory approval or Certificate of Public Convenience and Necessity ("CPCN") filing.

8.3. The Settling Parties agree that the Company should be authorized to establish a regulatory asset, with interest to accrue at the Company's weighted average cost of capital ("WACC"), to track and record the decommissioning costs of these units. Actual decommissioning costs that are incremental to those being collected through base rates shall be reviewed for prudence and for recovery in the Company's next-filed and litigated electric rate case.

9. Black Hills agrees to retain its Rocky Ford and Airport diesel units and to retire those units on their current retirement schedule or as authorized by the Commission in a future electric resource plan or other proceeding. The Settling Parties agree that the Company may seek recovery for decommissioning costs associated with these facilities as part of a future Commission filing.

E. ***Planning Reserve Margin***

10. The Settling Parties agree that the Company should use the following planning reserve margin ("PRM") for the duration of the RAP as follows:

10.1. Beginning in 2023, Black Hills will increase its PRM to 20 percent.

10.2. Black Hills will conduct a new PRM study for its 2026 ERP, and as part of that study commits to address the following issues raised by parties in this proceeding regarding PRM modeling assumptions, including:

10.2.1. Whether the 1-day-in-10-year loss of load expectancy ("LOLE") continues to be a reasonable and appropriate basis on which to develop Black Hills' PRM;

10.2.2. What the appropriate PRM would be for an increase in LOLE (*i.e.*, what is the required PRM for a 48-hours-in-10-year LOLE);

10.2.3. The impact of any regional market developments on Black Hills' proposed PRM; and,

10.2.4. Black Hills agrees to model, as a sensitivity, the inclusion of at least 100 MW of outside support from neighboring utilities (*i.e.*, short-term market purchases).

II. Phase II Portfolios and Transmission

11. The Settling Parties agree that the Commission should authorize the Company to move forward with its proposed Phase II competitive acquisition and bid evaluation process as set forth in the Company's Direct and Rebuttal Cases and subject to the modifications agreed to below.

A. Portfolios

12. The Settling Parties agree that the Commission should direct the Company to prepare the following portfolios, to be presented as part of the Company's 120-Day Report in Phase II of this Proceeding. Any additional portfolios not listed in this Settlement Agreement modeled by the Company and presented in the 120-Day Report must include a minimum of 80 percent emission reductions by 2030 from 2005 levels and include SCC and SCM in the capacity expansion step:

12.1. **Portfolio 1: ERP – No SC-GHG Portfolio**. The Settling Parties agree the Company may present, as an informational portfolio, a portfolio that includes no utility-ownership constraints and no emission reduction constraints. The purpose of this portfolio is to provide an illustrative view of the resources that would be required to meet load without consideration of SCC or SCM.

12.2. **Portfolio 2: Base ERP with SC-GHG – Least-Cost Portfolio**. This portfolio will include no utility-ownership constraints and no emission reduction constraints. The Company will *include* SCC and SCM in the capacity expansion step in this portfolio. The purpose of this portfolio is to provide the baseline portfolio of resources necessary to meet the utility forecast load and to serve as a basis for a determination of what incremental resources are needed to meet at least an 80 percent emissions reduction and the incremental cost of the portfolio that meets reduction consistent with § 40-2-125.5, C.R.S.

12.2.1. **Portfolio 2(a).** If Portfolio 2 shows that it meets CEP emission targets, then the Company shall be allowed to rerun this portfolio to include a target Company ownership of up to 50 percent of capacity, which shall be presented to parties in addition to the above-described Portfolio 2.

12.3. **Portfolio 3: Clean Energy Plan (Preferred Portfolio).** The Company's Preferred Portfolio, which may contain a utility ownership target of up to 50 percent and will achieve at least an 80 percent emission reduction by 2030 from 2005 levels. The Company will include SCC and SCM in the capacity expansion step. The Company retains the right to propose any portfolio, except Portfolio 1, as its Preferred Portfolio.

12.4. **Portfolio 4: 40 Percent Ownership Test.** This informational portfolio is similar to Portfolio 3, except it will include a utility ownership target of approximately 40 percent. The purpose of this portfolio is to provide a benchmark and test for whether the preferred portfolio and the Company ownership included within can be acquired at a "reasonable cost and rate impact," consistent with § 40-2-125.5(5)(b), C.R.S. This portfolio will include a minimum of 80 percent emission reduction by 2030 from 2005 levels. The Company will include SCC and SCM in the capacity expansion step.

12.5. **Portfolio 5: Geographic Diversity.** This portfolio will be consistent with the Company's Preferred Portfolio (Portfolio 3) but will contain and may emphasize generation projects: (i) not located in in the Company's service territory; and, either (ii) more than 10 miles from the nearest existing generation facility providing direct service to the Company's load, or (iii) in different Energy Resource Zones than those selected in the Preferred Portfolio. In crafting this portfolio, the Company will endeavor to balance geographic diversity with costs of additional transmission. This portfolio could be used to evaluate potential new transmission options, discussed in Section II.B below.

12.6. **Portfolio 6: Local Economic Development.** This portfolio will be consistent with the Company's Preferred Portfolio (Portfolio 3) but will contain and seek to emphasize projects located in or within 10-20 miles of the Company's service territory. This portfolio will also emphasize projects that contain commitments identified by the bidder that will further local economic development, such as community incentives, commitments to hire local businesses or labor, or other unique community partnerships or commitments.

12.7. **Portfolio 7**: **Participation within a Regional Market.** Black Hills agrees to model a portfolio incorporating the impact of its participation in a Regional Market, consistent with the approach outlined in portfolio 7 presented in Hearing Exhibit 102, Attachment MJH-1, page 107.

13. The Company agrees to run a sensitivity run on its Preferred Portfolio that considers 5 MW of demand response ("DR") by 2025, increasing to 10 MW of DR by 2030 (less than the Company's DR potential study: 12.7 MW in 2024 and 17.6 MW in 2032).

14. The Company will also identify preferred replacement bids for the purpose of addressing failed projects should that situation occur in the future, consistent with the Company's proposals in its Rebuttal Case.

15. Black Hills will include a discussion on any Company-owned bids in its 120-Day Report filed in this Proceeding discussing how it is working to minimize customer impacts due to deferred tax assets associated with projects that are included in any proposed portfolios.

16. Black Hills commits to running an additional informational, low-load portfolio to be provided to Pueblo County outside of the 120-Day Report that models a scenario that does not include electric load from Cañon City or City of Pueblo. Such portfolio shall be provided outside of the evidentiary record in this Proceeding and may not be relied upon in this Proceeding to impact the resources needed to support the Company's ERP and/or CEP presented and approved in this Proceeding. The Settling Parties will not challenge

the reasonableness of the costs to develop such portfolio, which are estimated to be approximately $10,000.

B. ***Transmission***

17. Black Hills will model additional transmission needs and cost estimates on a portfolio basis for each portfolio listed above, consistent with the Company's Direct Case,[2] and consistent with the Company's Federal Energy Regulatory Commission-approved Open Access Transmission Tariff. If portfolios that require additional transmission or transmission upgrades are included in the 120-Day Report, then these costs will not be included as a cost of the CEP in those CEP costs limited to one and one-half percent of the total electric bill annually pursuant to § 40-2-125.5(5)(a)(I), C.R.S.

18. The Company commits to explore the following transmission access options in Phase II:

18.1. Public Service Company of Colorado's ("PSCo") Power Pathway Project ("CPP"). The Company agrees to engage in discussions with PSCo regarding gathering information about the costs and terms under which Black Hills could potentially participate in the CPP within 30 days of the Phase I decision in this Proceeding as described in the Company's Rebuttal Testimony.[3] As described in this Settlement Agreement, the Company must report those findings and shall not participate in the CPP without making an additional filing. The Company will report on the status of these discussions at the time of release of the RFP, and in the 120-Day Report.

[2] *See, e.g.*, Hearing Exhibit 102, Attachment MJH-1 – Appendix N, at pages 14-16.

[3] *See, e.g.*, Hearing Exhibit 115, Rebuttal Testimony of Eric M. Egge, at pages 12-13.

18.2. Opportunities in the San Luis Valley, vis-à-vis the recently opened Commission Proceeding No. 22M-0514E; however, the outcome and recommended actions arising from Proceeding No. 22M-0514E may not be available prior to the issuance of the Phase II RFP.

18.3. The Company agrees that transmission identified in Black Hills' section of the most recent 10-Year Transmission Plan filed pursuant to Rule 3627 constitute Planned Transmission Lines for bidding purposes in this RFP. The Company will allow bids proposing a point of interconnection ("POI") to a Planned Transmission Line. For any portfolios with bids that rely on a Planned Transmission Line, the Company will present the cost of the portfolio, but also separately present the Company's indicative cost estimate associated with transmission delivery to the Company's system. A project bidding into a proposed POI to a Planned Transmission Line will simultaneously be allowed a second bid with a POI connecting to the Company's existing system without paying a second bid fee.

19. Nothing in this Section II.B shall commit the Company or its customers to incur additional transmission costs for its CEP at this time. The Settling Parties agree that any transmission identified under this Settlement Agreement does not represent a determination of need. If any new transmission opportunities are identified in bids in this resource planning process, Black Hills will make any appropriate filing(s) such as a Rule 3206 or standalone CPCN filing with the Commission and notify bidders of any additional transmission access points.

C. Phase II Load and Resources Table Update

20. The Company agrees to provide an updated detailed Load and Resource Balance table for its Preferred Portfolio (Portfolio 3) as part of its 120-Day Report.

III. Resource Acquisition Process – Model RFP, PPA, BTA Documents

A. Developed Build-Transfer Agreements

21. Black Hills agrees to update its model build-transfer agreement ("BTA") to more closely resemble its model PPAs as discussed in Mr. Harrington's Rebuttal Testimony,[4] to include: provision of a Project Risk Assessment Report providing required construction milestones, increased assurances, and penalties for failure to meet critical milestones, including project termination, as reflected in Hearing Exhibit 111, Attachment MJH-5 provided in the Company's Rebuttal Case.

B. PAGS Units 4 and 5 Fast Start Capabilities

22. Black Hills agrees to update its RFP to clarify that bids for fast-start capabilities at Pueblo Airport Generating Station ("PAGS") units 4 and 5 (owned by Black Hills' independent power producer ("IPP") affiliate), may be submitted and considered as part of its Phase II resource acquisition process. The bidder may elect to bid a project with multiple pricing options (including but not limited to, *e.g.*, fixed or escalating pricing) without paying an extra bid fee. In analyzing such a bid with computer-based modeling, the Company will include all variations of bid pricing as part of the computer-based modeling.

[4] *See* Hearing Exhibit 111, Rebuttal Testimony of Michael J. Harrington, at 49:15-20.

22.1. If such a bid is submitted, the Company agrees to evaluate and analyze the bid as part of its 120-Day Report, including a discussion of why it was or was not selected as part of any portfolio.

C. 100 MW Size Preference

23. Black Hills agrees to update its RFP to establish a preference of bid sizes of approximately 100 MW on any generation project bid into its RFP. The intent of this provision is to mitigate against the risk of bid failures and promote geographic diversity.

D. Compensable Curtailments

24. Black Hills agrees to compensate generation owners for curtailments by removing the provision regarding Compensable Curtailments from its model PPA contract and BTA contracts. Black Hills will model unit-level curtailments with the appropriate cost for Production Tax Credit ("PTC") compensation, where applicable.[5]

24.1. Bidders may elect to bid a project with multiple pricing options (including but not limited to, *e.g.*, fixed or escalating pricing, a wind or solar project with and without a compensable PTC, a solar project with an Investment Tax Credit ("ITC"), or a solar plus storage project bid with an energy payment or an energy and capacity payment, respectively) without paying an extra bid fee. Pricing variations on a particular bid will be evaluated individually to determine whether the bid will advance to computer-based modeling. If a project is advanced to computer-based modeling, all offered pricing variations on the project will be advanced and modeled in the Phase II process.

[5] See Hearing Exhibit 1300, Answer Testimony of Warren L. Wendling at 57:12-17 and Attachment WLW-3, p. 28 (Company response to Discovery Request CIEA 2-4).

E. ***Finance Lease***

25. The Settling Parties agree the Company may allow solar and solar plus storage projects to bid and contract for capacity payments for the battery facilities. In recognition of the Company's concern with the 75/90 rule, battery facilities in such PPA structures shall be limited to an initial term of 18 years and sized up to 50 MW based on the Company's Phase I resource analysis. CIEA commits to conferring with the Company prior to the issuance of its RFP to identify what documentation bidders can reasonably provide the Company regarding battery life expectancy of any storage bid as part of their bid submission.

F. ***Bid Evaluation and Scoring***

26. The Settling Parties agree that the Commission should approve the Company's initial eligibility screening process and modified 100-point bid scoring, ranking, and evaluation process as set forth in the Company's Rebuttal Case.[6] The Company will advance bids to computer-based modeling consistent with the process, including the 100-point scoring and ranking system identified in Hearing Exhibit 102, Attachment MJH-1 – Appendix N and the Company's Rebuttal Case.

27. In order to implement the statutory obligations of § 40-2-129(1)(a)-(b), C.R.S. and § 8-17-101(2)(a), C.R.S., Best Value Employment Metrics statutes ("BVEM"), to implement the policy of the State of Colorado to keep quality jobs within Colorado and to support implementation of the recommendations of the Performance Audit conducted by the State of Colorado Auditor in July 2022, the Company will grade each bid proposal as to how the

[6] *See* Hearing Exhibit 112, Rebuttal Testimony of Amanda M. Thames, at 22:10 – 23:4.

proposal complies with BVEM, advancing only those proposals that are compliant with statutory requirements for these metrics. The Company will advise potential bidders of the required metrics and the scoring and ranking system that it will use, and will inform bidders that the Company has determined are not compliant along with providing the bid BVEM scores. The Company will provide documentation on the compliance metrics and scoring/ranking system in the RFP documents, will make itself available to discuss questions at the pre-bid conference, and will hold at least one further question and answer session with bidders to discuss follow up questions after the pre-bid conference and before bids are due to be submitted.

28. Black Hills agrees to require that bidders indicate whether they have included anticipated tax credits in their bids, regardless of whether the bidders are Company affiliates or third-party entities.

29. Black Hills agrees to evaluate utility-owned generation proposals using the levelized cost of energy ("LCOE") in the same manner as non-utility-owned projects before advancing any utility-owned proposed projects to computer modeling. However, in consideration that bids for PAGS units 4 and 5 fast-start capabilities will not add new generation or storage capacity to the system, such bids may not be evaluated using the 100-point scoring and ranking system discussed above.

30. If the Company's IPP affiliate decides to submit any bid(s) into the Company's RFP, Black Hills will implement a formal, written separation protocol, ensuring that the Company's bid evaluation team is fully walled off from any discussions or communications related to this Proceeding and the Company's resource acquisition process generally, until a final Phase II decision has been entered in this Proceeding.

31. Black Hills agrees to provide a project risk assessment report regarding any projects bid by the Company's IPP affiliate, with any such risk assessment to be presented in conjunction with the Company's 120-Day Report. Black Hills agrees to provide the parties the topics and level of detail it expects to be included in a Project Risk Assessment Report and to discuss the same with bidders in the RFP documents and at the pre-bid conference meeting with IPPs.

32. As part of the Company's 120-Day Report, it will make best efforts to map the location of all bids that advance to computer-based modeling in relation to DI Communities based on the Colorado Department of Public Health and Environment's ("CDPHE") EnviroScreen mapping tool.

G. Tail Modeling

33. Settling Parties agree to the replacement chain method and the annuity method as bookend optimizations for the following portfolios: (1) ERP baseline, (2) CEP Preferred, (3) 40 percent ownership, and (4) Geographic Diversity.

IV. 2023-2026 RES Plan

34. The Settling Parties agree that the Commission should approve the Company's 2023-2026 RES Plan as set forth in Hearing Exhibit 102, Attachment MJH-2, as modified by the Company's Rebuttal Case and the terms and conditions of this Settlement Agreement.

34.1. Black Hills agrees to modify its proposed definition of "Income Qualified Customer" to the statutory definition of "low-income" established by SB 21-272 in § 40-2-108(3)(d)(III), C.R.S.

35. The Settling Parties agree the Company's RES Plan is reasonably designed to result in compliance with the State's RES requirements for purposes of its 2023-2026 RES Plan.

36. The Settling Parties agree that the Commission should approve the Company's 2023-2026 on-site solar, off-site net metering, and storage incentives and annual available capacity levels as proposed in the Company's Rebuttal Case, as follows:[7]

Program	**Available Annual Capacity**	**Incentives**
Solar and Storage (IQ) 0.5 kW – 25 kW	0.25 MW	• PBI = $0.038/kWh • $1/watt solar system rebate payment • $100/kW paired storage system rebate payment with a maximum rebate of $1,000 per customer
Solar and Storage (Regular) 0.5 kW – 25 kW	1.75 MW	• PBI = $0.0025/kWh • $100/kW paired storage system rebate with a maximum rebate of $1,000 per customer
Solar (Large) 25 kW – 250 kW	0.25 MW	• PBI = $0.02/kWh
Off-site net metering service pursuant to § 40-2-124(1)(e)(I)(E), C.R.S., as set forth in the Company's Commission-approved Off-Site Net Metering Service Electric Tariff[8]	Target of 0.25% of 2021 and 2022 retail kWh sales; no cap	• 0 incentive
Total	**2.25 MW**	

37. The Settling Parties agree that the Commission should approve annual maximum capacity acquisition levels for the Company's 2023-2026 Community Solar Garden ("CSG") program as follows:

[7] *See* Hearing Exhibit 108, Rebuttal Testimony of Dr. Devin Moeller, at Table DJM-11.

[8] Black Hills Colorado Electric, LLC d/b/a Black Hills Energy Colo. PUC No. 11.

37.1. A maximum capacity of 1.5 MW per year for the Standard Offer (IQ), to be managed by the Company and through its existing web portal process as identified in its Direct Case, including a minimum of 500 kW for donated subscriptions. Black Hills commits to the conditions outlined in Attachment A for managing the donated subscriptions and commits to reevaluating annually whether third-party subscription management would be more appropriate and/or more cost-effective for customers than Company management.

37.1.1. Of the 1.5 MW Standard Offer, Black Hills will set aside 500 kW for any residential customers (whether or not they qualify as IQ) who reside within a Disproportionately Impacted ("DI") Community; any unused capacity at the end of the year will roll forward to the general Standard Offer capacity. The Company will fulfill the 500 kW DI Community capacity through requiring Standard Offer participants to set aside a minimum of 200 kW for DI Communities until the 500 kW threshold is met (this would be filled through at least 200 kW for the first two Standard Offer projects and at least 100 kW for the third Standard Offer project). Developers shall be responsible for verifying subscribers are members of a DI Community.

37.2. A maximum capacity of 2 MW per year for the Open RFP.

37.3. All awarded CSG standard offers and RFP bids will comply with Commission Rule 3882(a)(I).

37.4. The Company agrees to use Commission Rule 3661(h) to determine annual CSG cost allocation between ECA and Renewable Energy Standard Adjustment ("RESA") including consideration of CSG bill credits.

37.5. To the extent Black Hills decides to materially modify its form CSG contracts, or award criteria, Black Hills agrees to first confer with Staff and provide written notice either through its annual RES reporting or a notice filed in this Proceeding.

38. The Company agrees to simplify paperwork requirements for eligible IQ CSG subscribers by waiving: (1) the Subscriber Agency Agreement requirement, and (2) the Consent to Disclose Utility Customer Data form, only if the customer has already provided the Company with the Consent to Disclose Utility Customer Data form in connection with another program and/or receives assistance through a third-party to whom the customer has already provided this form.

39. The Company agrees to file an update in this Proceeding regarding the feasibility and costs of implementing bill credit donations, within six months of a final Commission decision approving this RES Plan.

40. The Company agrees to file an update in this Proceeding regarding development of its CSG program web-based portal, upon completion of the portal or at the time of the Company's 2023 CSG offerings, whichever occurs first.

41. Going forward, Black Hills agrees to charge CSG bill credits to the RESA/ECA based on the incremental/avoided cost methodology (*i.e.*, with avoided costs to be charged to the ECA and incremental costs to the RESA).

42. The Settling Parties agree that the Company may use the updated solar agreements and CSG RFP process as discussed in Dr. Moeller's Direct Testimony.[9]

43. In the event that IQ/DI Community RES spending is below 40 percent of the RES Plan budget, the difference between the actual spend and the required 40 percent minimum will be rolled into the following year.

A. __RES Plan IQ/DI Community Outreach and Engagement__

44. Black Hills agrees to allow multiple third-party entities to provide income verification services for purposes of determining customer eligibility for IQ/DI Community offerings under the RES Plan.

45. Settling Parties agree that the Company's planned program expenditures, as set forth in its Rebuttal Case and modified by this Settlement Agreement, meet the IQ/DI Community funding requirements of SB 21-272.

    45.1. Settling Parties acknowledge that future RES Plans may be impacted by the Commission's ongoing rulemaking process to implement SB 21-272.

46. Black Hills will require every CSG project which has a commitment to subscribe all or some of the project capacity to IQ customers to submit answers to the following questions, on a form provided by the Company in the RFP and Standard Offer processes, in order to demonstrate readiness to serve the IQ community:

    46.1. Does your company have experience with IQ subscriber acquisition and management? Please describe your experience.

[9] Hearing Exhibit 108 at 35 – 41.

46.2. Will you partner with a third-party to conduct IQ subscriber outreach, enrollment, and/or management? If yes, please provide the name of the entity or organization with confirmation from the entity or organization.

46.3. How will your company or partner identify, reach, and engage with prospective IQ subscribers?

46.4. Who will be the point of contact for IQ subscribers during enrollment and throughout their subscription duration?

47. The Company has discretion to request follow-up information or reject projects if it determines the subscriber organization lacks a sufficient plan for outreach, enrollment, and management. Such submissions will be afforded the same level of confidentiality treatment as other bid submission forms.

48. Black Hills agrees to implement an IQ/DI Community engagement and outreach plan and agrees to take the following steps towards that end:

48.1. Black Hills agrees to work with relevant stakeholders, including Community Based Organizations ("CBOs"), to identify organizations serving IQ customers and DI Communities that can support community engagement/outreach and program implementation;

48.2. Black Hills agrees to coordinate with frontline CBOs to support program implementation and outreach plan development, education, and outreach efforts;

48.3. Black Hills will strive to identify and hire local businesses who serve the community, where appropriate;

48.4. Black Hills will use CDPHE's EnviroScreen mapping tool to identify DI Communities for purposes of RES Plan implementation, until or unless the

Commission adopts rules or authorizes the Company to use another resource/method;

48.5. Black Hills will use the outreach plan and data collected as the basis for future IQ/DI Community programming and engagement proposals, including for this RES Plan;

48.6. During this RES Plan, Black Hills will use a 60/90-Day Notice process to modify IQ/DI Community RES Plan offerings based on the outreach and engagement process, with notice provided to existing RES Plan stakeholders as well as any new stakeholders identified through the Company's IQ/DI Community engagement efforts;

48.7. If Black Hills chooses not to modify its RES Plan offerings following the engagement and outreach process, Black Hills will file a notice with the Commission detailing why no modifications are recommended following its outreach and engagement. Parties to this proceeding, participants in the outreach and engagement process, and residents of DI Communities shall be able to respond to Black Hills' notice within a 30-day time frame; and,

48.8. Black Hills may propose to expand the scope of areas covered by the outreach plan as part of a future proceeding (*e.g.*, expand into DSM offerings) with funds from non-RESA sources.

49. The Settling Parties agree that Black Hills will establish a flexible budget of $15,000 annually to be spent on RES-specific IQ/DI Community outreach and engagement efforts, which may include directly supporting CBO partners.

49.1. This flexible outreach and engagement budget will be separate from the funds dedicated to IQ/DI RES program costs. The flexible budget will be funded and recovered through the RESA consistent with the treatment approved in PSCo's most recent RES Plan in Proceeding No. 21A-0625EG. This flexible budget will not contribute to costs subject to the RESA administrative cost cap.

49.2. Black Hills agrees to report on its IQ/DI Community engagement and outreach efforts and progress through its annual RES reporting. This will include reporting on IQ/DI participation in RES programming by program, to the extent feasible.

49.3. Black Hills agrees to provide, on an aggregate basis as defined in Rule 3001(b) and where aggregated reporting is not prohibited by the Commission's data privacy rules, the following information on CSG participation through its annual RES reporting: (1) the number of IQ and DI customers, to the extent practicable, enrolled in active CSGs; (2) the associated kW allocation of those customers; and, (3) the bill credits received by those customers, each broken down by customer rate class; additionally, to the extent practicable and reasonably feasible after a Commission rulemaking concludes, Black Hills will report on the number of IQ customers in the CSG program who are also residing in a DI Community.

B. <u>Consideration of Additional Renewable Energy Customer Programs</u>

50. Black Hills agrees to meet with Walmart Inc. and other interested customers on the development of a new green tariff-style customer program by August 31, 2023. In the event a new program is developed, the Company will make appropriate filings to

implement it. Parties to the settlement may take any position with respect to these future filings.

V. <u>Cost Recovery</u>

A. <u>CEPR</u>

51. The Settling Parties recognize the importance of managing costs associated with the Company's CEP, recognizing for instance, the result of the Commission's recent *Electric Retail Rate Survey Report*.[10] The Settling Parties agree that it is appropriate for the Commission to determine the need for a CEPR and the appropriate cost recovery structure for the Company's CEP as part of Phase II of this Proceeding.

51.1. To accomplish this, the Company will present, as part of its 120-Day Report, several cost recovery options for its Preferred Portfolio (as detailed in Section II above), including the associated total bill impacts through 2030 of each option (including, for example, all riders, adjustment clauses, and transmission cost estimates), and identify the Company's recommended approach. Settling Parties may respond to these options through their responsive comments due 45 days after the 120-Day Report is filed. The intent of providing these cost recovery options is to provide the parties to this Proceeding with information showing the estimated maximum and minimum bill impacts of the Company's Preferred Portfolio through 2030.

[10] *Electric Retail Rate Survey Report* (Feb. 1, 2021), Proceeding No. 20M-0251E.

51.2. In lieu of discovery, the Company agrees to conduct a technical conference for all parties to this Proceeding within 14 calendar days of filing its 120-Day Report to present and discuss the cost recovery options presented in its 120-Day Report.

52. In the interests of providing the estimated cost and bill impacts of the Company's CEP based on this Settlement Agreement and the Company's Phase I modeling, Attachment B is a workpaper with the Company's estimated cost and bill impacts.

53. Regarding the cost recovery options the Company presents, at a minimum, the Company will:

53.1. Present a cost recovery option that does not include the use of the CEPR, but rather all costs associated with its Preferred Portfolio are recovered through existing mechanisms.

53.2. Present at least one cost recovery option that includes a CEPR. At a minimum, the Company will place any incurred costs, until a CEPR is in place, into a regulatory account for future recovery in the Company's next electric rate case. The recovery and interest of this regulatory account will be determined at the time of the Company's electric rate case, and Black Hills agrees the maximum carrying cost will be no greater than the rate of the US Seven-Year Treasury Rate over the deferral period. Alternatively, the Company could seek to recover prudent costs through use of the current RESA balance.

53.3. Present at least two options for use of Black Hills' existing and forecasted RESA surplus. Parties acknowledge that Black Hills is authorized to transfer up to 50 percent of any RESA surplus to the CEPR, to be calculated based on the balance of the RESA at the time the CEPR goes into effect. Black Hills may present additional options, including but not limited to, transferring a portion of the RESA surplus to pay down its ECA balance. Black Hills commits to condition its cost recovery recommendation(s) on showing that the transfer will not result in a negative RESA balance for each of the years 2026 through 2030.

54. If a CEPR is approved, the Settling Parties agree to the following parameters:

54.1. The carrying cost shall be symmetrically set for any over- or under-collections at the Company's most-recently approved WACC consistent with Rule 3660(e)'s treatment of RESA over- and under-collections.

54.2. If the CEPR surcharge is delayed until 2026, the Company will place any incurred costs, until a CEPR is in place, into a regulatory account for future recovery in the Company's next electric rate case. The recovery and interest of this regulatory account will be determined at the time of the Company's electric rate case, and Black Hills agrees the maximum carrying cost will be no greater than the rate of the US Seven-Year Treasury Rate over the deferral period. Alternatively, the Company could seek to recover prudent costs through use of the current RESA balance. .

54.3. The Settling Parties agree that if a CEPR is proposed for approval in Phase II of this Proceeding, CEPR-eligible costs shall be a net calculation, determined via the subtracted difference between the costs of the CEP portfolio ultimately selected by the Commission and the Base ERP portfolio with SCC, excluding fuel, transmission, and RES-related costs as detailed in § 40-2-125.5, C.R.S. (5)(a)(III). If a CEPR is approved in Phase II of this Proceeding, the Settling Parties agree that the Commission should authorize Black Hills to implement the

CEPR surcharge to customers' bills in the amount of 1.5 percent or less based on actual costs determined following Phase II of this Proceeding.

B. RESA

55. Regarding the RESA, the Settling Parties agree that the Commission should make the following approvals and authorizations as part of its Phase I decision in this Proceeding:

55.1. Authorize Black Hills to reduce the RESA from 2 percent to 1 percent, which the Company may effectuate through a compliance Advice Letter filing after a final Phase II decision is issued in this Proceeding. The Company commits to reevaluating its RES Plan funding needs and the appropriate RESA level as part of its next ERP and/or RES Plan, which are expected to be filed in 2026.

55.2. Authorize Black Hills to discontinue collecting Busch Ranch I and II costs from the RESA, and recover all costs associated with these facilities through the ECA on a going-forward basis. Should Black Hills in the future project a RESA deficit, Black Hills may propose different treatment in the future to mitigate a projected RESA deficit.

55.3. Except for Busch Ranch I and II, Black Hills agrees to use a RESA-ECA process where the cost of a high-cost renewable project will have a portion of its costs charged to the ECA at the avoided cost with the rest of the cost going to the RESA. Low-cost renewable projects will have their actual costs recovered through the ECA with no cost to the RESA.

55.4. The Company will withdraw its requested waiver of Rule 3660(e) and will implement the referenced rule interest on prospective over- or under-collected balance.

C. Treatment of Black Hills' Fees and Costs

56. The Settling Parties agree that the Commission should authorize Black Hills to track and defer fees and costs associated with preparing and litigating this Proceeding, to be offset by any bid fees received as part of the Phase II solicitation process. The Settling Parties agree that legal fees shall be allocated 80/20 between ERP/CEP and RES support, respectively. All ERP/CEP costs and fees incurred related to this Proceeding shall be tracked through a non-interest bearing regulatory asset and presented for recovery through the Company's next-filed electric rate case. The Company may recover its RES legal fees and costs through the RESA.

VI. Reporting

57. Black Hills agrees to track, as part of this Proceeding, any IRA and/or IIJA funds awarded to Black Hills. Black Hills will report to the Commission on funds applied for and awarded to Black Hills pursuant to the IRA or IIJA as part of future ERP or RES compliance filing(s) or reports as appropriate.

58. Black Hills will continue to report on an annual basis, the cost of all renewable energy resources and all cost recovery implemented including, but not limited, to the RESA, the ECA, base rates, or any other cost recovery riders.

VII. Waivers and Variances

59. The Settling Parties agree the Commission should approve Black Hills' Motion for Waiver from Commission Rules 3606(a)(II), 3606(a)(V), and 3606(a)(VI). Settling Parties agree these waivers shall be limited to this Proceeding alone. Black Hills will commit to providing this information through its next electric rate case, electric DSM Plan, or ERP, whichever is filed sooner.

60. For Busch Ranch cost recovery, the Settling Parties agree to the Company's waiver requests for Rules 3660(b), 3661(a), and 3661(h).

61. The Settling Parties agree to the Company's waiver requests for Rules 3658(f)(II), 3658(f)(VIII), 3661(d), 3652(ff), 3664(a), and 3878(b), and, for Busch Ranch ECA recovery as necessary, as set forth in the Company's Motion for Waivers.

62. The Settling Parties agree to the Company's temporary waiver requests for Rule 3661(d) only through Commission final decision in next RES Plan. Administrative cost will be capped at twenty percent of RESA collection.

VIII. Regulatory Compliance

63. The Settling Parties agree that the Commission should authorize the Company to implement any and all tariffs and tariff changes necessitated by the Commission's decision in this Proceeding through one or more compliance advice letter filing(s) on not less than two business days' notice. Settling Parties agree not to challenge any such filing(s).

64. The Settling Parties agree that the Commission should grant all other necessary approvals and relief necessary to implement the Company's proposals set forth in its Application, as modified by this Settlement Agreement.

GENERAL PROVISIONS

65. 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.

66. 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.

67. 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.

68. 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.

69. 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.

70. 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.

71. 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.

72. 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.

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

74. 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 13th day of January, 2023.

Agreed on behalf of:

Black Hills Colorado Electric, LLC
d/b/a Black Hills Energy

By: *<u>/s/ Michael J. Harrington</u>*
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Agreed on behalf of:

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*This approval is contingent on a vote of the three commissioners at a noticed public board meeting of the Pueblo County Commission that will be held next week.

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		CLEAN ENERGY PLAN RIDER (CEPR)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
		Total Revenue (3 year average: 2019 - 2021)		272,608,019	275,334,099	278,087,440	280,868,314	283,676,998	286,513,768	289,378,905	292,272,694	295,195,421	298,147,375	301,128,849
		CEPR Factor						0.71%	0.71%	0.71%	0.71%	0.71%		
		CEPR Revenue		-				2,026,968	2,047,238	2,067,710	2,088,387	2,109,271	-	-
		Incremental cost (Difference between CEP and Base No SCC of Capital and FOM Costs)												
		Forecasted Cost of 2025 3 MW Wind Resource		-	-	-	-							
		Forecasted Cost of 2025 225 MW Solar Resource		-	-	-	-							
		Forecasted Cost of 2025 50 MW Battery Resource		-	-	-	-	$ 1,969,200	$ 1,969,200	$ 1,969,200	$ 1,969,200	$ 1,969,200		
		Forecasted Cost of 2030 97 MW Wind Resource		-	-	-	-	-	-	-	-			
		Diesel Decomissioning Costs		-								-	-	-
		Diesel Accelerated Depreciation			120,880	120,880	120,880							
		Total Costs Recoverable in CEPR		-	120,880	120,880	120,880	1,969,200	1,969,200	1,969,200	1,969,200	1,969,200	-	-
		Total CEPR Recoveries minus total CEPR costs			(120,880)	(120,880)	(120,880)	57,768	78,038	98,510	119,187	140,071	-	-
WACC	**WACC**	Cumulative CEPR		-	(120,880)	(246,323)	(381,065)	(346,981)	(296,426)	(222,205)	(122,596)	4,460		
0.0755	0.0755	Interest		-	(4,563)	(13,862)	(23,684)	(27,484)	(24,289)	(19,578)	(13,016)	(4,460)		
		RESA Balance Transfer			-	-	-							
		Balance - (Under)/Over Collected		**-**	**(125,443)**	**(260,185)**	**(404,749)**	**(374,464)**	**(320,715)**	**(241,783)**	**(135,612)**	**(0)**	**-**	**-**

		RENEWABLE ENERGY STANDARD ADJUSTMENT (RESA)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
		Total Revenue (3 year average: 2019 - 2021)		272,608,019	275,334,099	278,087,440	280,868,314	283,676,998	286,513,768	289,378,905	292,272,694	295,195,421	298,147,375	301,128,849
		RESA Factor		2.00%	1.00%	1.00%	1.00%	1.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
		RESA Revenue		5,452,160	2,753,341	2,780,874	2,808,683	2,836,770	5,730,275	5,787,578	5,845,454	5,903,908	5,962,948	6,022,577
		REC Cost:												
		Total REC Costs:		**25,555,940**	**16,013,816**	**16,762,137**	**18,327,283**	**19,685,753**	**8,759,899**	**9,392,197**	**9,236,713**	**8,655,735**	**8,246,160**	**7,457,885**
		Avoided Costs:												
		Total Avoided Costs		**(26,430,561)**	**(14,888,954)**	**(14,111,614)**	**(13,428,686)**	**(13,230,642)**	**(2,882,031)**	**(2,846,850)**	**(2,571,264)**	**(2,304,465)**	**(2,137,624)**	**(2,071,430)**
		Net REC Costs - Recoverable through RESA		(874,622)	1,124,862	2,650,523	4,898,597	6,455,111	5,877,868	6,545,347	6,665,449	6,351,270	6,108,536	5,386,455
		Program Costs:												
		IQ/DI Flexible Budget			15,000	15,000	15,000	15,000						
		Forecast		545,216	561,573	578,420	595,772	613,645	632,055	651,016	670,547	690,663	711,383	732,725
		Total Costs Recoverable through RESA		(329,406)	1,701,434	3,243,942	5,509,370	7,083,757	6,509,923	7,196,363	7,335,996	7,041,933	6,819,919	6,119,180
		Total RESA Revenues minus Total Costs Recoverable from RESA		5,781,566	1,051,907	(463,068)	(2,700,686)	(4,246,987)	(779,647)	(1,408,785)	(1,490,542)	(1,138,025)	(856,972)	(96,603)
CDR	WACC	Cumulative		13,343,192	13,130,029	12,677,553	9,987,194	5,749,277	4,975,928	3,571,436	2,084,314	948,553	92,795	(3,391)
0.0008	0.0755	Interest		8,362	10,593	10,327	9,070	6,298	4,293	3,421	2,264	1,214	417	3,391
		Regulatory Filing Costs			332,400									
		Balance - (Under)/Over Collected	**7,561,626**	**13,351,554**	**13,140,621**	**12,687,881**	**9,996,264**	**5,755,575**	**4,980,221**	**3,574,856**	**2,086,578**	**949,767**	**93,212**	**(0)**
		RESA Transfer to ECA		(1,273,432)										

ENERGY COST ADJUSTMENT (ECA)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	
Estimated Generation		$ 2,574,846	$ 1,748,951	$ 923,055	$ 97,160	$ 99,500	$ 101,841	$ 104,181	$ 106,521	$ 108,862	$ 412,320	$ 715,778	
Estimated Purchases for System		$ 46,618,912	$ 51,011,321	$ 45,316,615	$ 39,628,171	$ 37,372,641	$ 35,123,722	$ 32,881,595	$ 30,646,448	$ 28,418,472	$ 27,565,987	$ 26,073,381	
Net RESA Transfer		$ 26,249,150	$ 14,606,211	$ 13,577,089	$ 12,619,450	$ 12,077,666	$ 1,524,915	$ 1,397,345	$ 1,233,505	$ 1,070,834	$ 960,687	$ 894,493	
Forecasted Cost of 2025 3 MW Wind Resource		$ -	$ -	$ -	$ -	$ 520,604	$ 520,604	$ 520,604	$ 520,604	$ 520,604	$ 520,604	$ 520,604	
Forecasted Cost of 2025 225 MW Solar Resource		$ -	$ -	$ -	$ -	$ 13,174,524	$ 13,174,524	$ 13,174,524	$ 13,174,524	$ 13,174,524	$ 13,174,524	$ 13,174,524	
Forecasted Cost of 2025 50 MW Battery Resource		$ -	$ -	$ -	$ -	$ 2,953,800	$ 2,953,800	$ 2,953,800	$ 2,953,800	$ 2,953,800	$ 2,953,800	$ 2,953,800	
Forecasted Cost of 2030 97 MW Wind Resource		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	13,604,591	13,604,591	13,604,591	
											1,969,200	1,969,200	
RESA Transfer						(1,273,432)							
Total		**$ 75,442,908**	**$ 67,366,483**	**$ 59,816,759**	**$ 52,344,781**	**$ 66,198,735**	**$ 53,399,405**	**$ 51,032,049**	**$ 48,635,402**	**$ 59,851,688**	**$ 59,192,514**	**$ 57,937,172**	
Estimated Sales (kWh)		2,045,304,055	2,045,304,055	2,045,304,055	2,045,304,055	2,052,525,674	2,059,747,293	2,066,968,912	2,074,190,532	2,081,412,151	2,088,669,917	2,095,927,683	
Energy Cost Adjustment		$ 0.03689	$ 0.03294	$ 0.02925	$ 0.02559	$ 0.03225	$ 0.02593	$ 0.02469	$ 0.02345	$ 0.02876	$ 0.02834	$ 0.02764	
Total Settlement Cost		75,113,502	69,188,797	63,181,581	57,975,031	75,251,692	61,878,528	60,197,612	57,940,598	68,862,821	66,012,433	64,056,352	719,658,947
Total Original Cost- (Attachment DSA-1 Direct Testimony)		75,113,502	71,384,441	63,715,225	60,213,675	77,465,634	64,107,469	62,426,554	60,785,539	77,788,614	76,907,426	74,951,345	764,859,423
		-	(2,195,644)	(533,644)	(2,238,644)	(2,213,941)	(2,228,941)	(2,228,941)	(2,844,941)	(8,925,793)	(10,894,993)	(10,894,993)	(45,200,476)
												Orginal CEPR Reg Asset	(56,988,931)
												Total Settlement Savings	**(102,189,407)**

denotes new Edits

ECA as shown for Proposed April 1, 2022 Effective Date

CUSTOMER CALCULATION	Current Rates	Current Bill	January 1, 2023 Rates		January 1, 2023 Bill	Increase/ (Decrease) from FORMER	Increase/ (Decrease) from FORMER	January 1, 2026 Rates		January 1, 2026 Bill	Increase/ (Decrease) from FORMER	Increase/ (Decrease) from FORMER
Residential General (RS-1) - CO860												
Customer Charge	$ 8.77	$ 8.77	$ 8.77		$ 8.77			$ 8.77		$ 8.77		
Energy Charge First 500 kWh	$ 0.09999	$ 50.00	$ 0.09999	x 600 kWh	$ 50.00			$ 0.09999	x 600 kWh	$ 50.00		
Energy Charge All Over 500 kWh	$ 0.1300	$ 13.00	$ 0.1300		$ 13.00			$ 0.1300		$ 13.00		
GRSA	-3.7523%	$ (2.69)	-3.7523%		$ (2.69)			-3.7523%		$ (2.69)		
ECA	$ 0.05101	$ 30.61	$ 0.03294		$ 19.76			$ 0.03225		$ 19.35		
RESA	2.00%	$ 2.18	1.00%		$ 0.98			1.00%		$ 0.98		
PCCA	$ 0.00145	$ 0.87	$ 0.00145		$ 0.87			$ 0.00145		$ 0.87		
DSMCA	2.75%	$ 2.92	2.75%		$ 2.62			2.75%		$ 2.61		
TCA	$ 0.005072	$ 3.04	$ 0.005072		$ 3.04			$ 0.005072		$ 3.04		
CACJ Adjustment	$ 0.00444	$ 2.66	$ 0.00444		$ 2.66			$ 0.00444		$ 2.66		
BHEAP Funding Fee	$ 0.51	$ 0.51	$ 0.51		$ 0.51			$ 0.51		$ 0.51		
EGCRR	$ 0.00579	$ 3.47	$ 0.00579		$ 3.47					$ -		
CEPR			0.00%		$ 1.45			0.71%		$ 0.69		
EASBC	$ 0.50	$ 0.50	$ 0.50		$ 0.50			$ 0.50		$ 0.50		
Monthly Bill Calculations		$ 115.85			$ 104.95	$ (10.90)	-9.41%			$ 100.29	$ (4.66)	-4.65%

Expanded use of the RESA for incremental cost recovery - 40-2-125.5

(VIII) If the minimum amounts of electricity from eligible energy resources set forth in section 40-2-124 (1)(c) are satisfied, a qualifying retail utility may propose to use up to one-half of the funds collected annually under section 40-2-124 (1)(g), as well as any accrued funds, to recover the incremental cost of clean energy resources and their directly related interconnection facilities. The utility may account for these funds in calculating the cost of the plan.

40-2-124 (c) Electric resource standards:

(I) Except as provided in subparagraph (V) of this paragraph (c), the electric resource standards shall require each qualifying retail utility to generate, or cause to be generated, electricity from eligible energy resources in the following minimum amounts:

(A) Three percent of its retail electricity sales in Colorado for the year 2007;

(B) Five percent of its retail electricity sales in Colorado for the years 2008 through 2010;

(C) Twelve percent of its retail electricity sales in Colorado for the years 2011 through 2014, with distributed generation equaling at least one percent of its retail electricity sales in 2011 and 2012 and one and one-fourth percent of its retail electricity sales in 2013 and 2014;

(D) Twenty percent of its retail electricity sales in Colorado for the years 2015 through 2019, with distributed generation equaling at least one and three-fourths percent of its retail electricity sales in 2015 and 2016 and two percent of its retail electricity sales in 2017, 2018, and 2019; and

(E) Thirty percent of its retail electricity sales in Colorado for the years 2020 and thereafter, with distributed generation equaling at least three percent of its retail electricity sales.

CEPR = ERP Portfolio - CEP portfolio - RESA recoveries - Other rider mehanisms

	2024		2025		2026		2027		2028		2029		2030	
Customer Charge	$ 8.77	$ 8.77	$ 8.77	$ 8.77	$ 8.77	$ 8.77	$ 8.77	$ 8.77	$ 8.77	$ 8.77	$ 8.77	$ 8.77	$ 8.77	$ 8.77
Energy Charge First 500 kWh	$ 0.09999	$ 50.00	$ 0.09999	$ 50.00	$ 0.09999	$ 50.00	$ 0.09999	$ 50.00	$ 0.09999	$ 50.00	$ 0.09999	$ 50.00	$ 0.09999	$ 50.00
Energy Charge All Over 500 kWh	0.13	$ 13.00	0.13	$ 13.00	0.13	$ 13.00	0.13	$ 13.00	0.13	$ 13.00	0.13	$ 13.00	0.13	$ 13.00
GRSA	$ (0.037523)	$ (2.69)	$ (0.037523)	$ (2.69)	$ (0.037523)	$ (2.69)	$ (0.037523)	$ (2.69)	$ (0.037523)	$ (2.69)	$ (0.037523)	$ (2.69)	$ (0.037523)	$ (2.69)
ECA	$ 0.02925	$ 17.55	$ 0.02559	$ 15.36	$ 0.03225	$ 19.35	$ 0.02593	$ 15.56	$ 0.02469	$ 14.81	$ 0.02345	$ 14.07	$ 0.02876	$ 17.25
RESA	1%	$ 0.96	1%	$ 0.94	1%	$ 0.98	2%	$ 1.87	2%	$ 1.86	2%	$ 1.84	2%	$ 1.91
PCCA	$ 0.00145	$ 0.87	$ 0.00145	$ 0.87	$ 0.00145	$ 0.87	$ 0.00145	$ 0.87	$ 0.00145	$ 0.87	$ 0.00145	$ 0.87	$ 0.00145	$ 0.87
DSMCA	2.75%	$ 2.56	2.75%	$ 2.50	2.75%	$ 2.61	2.75%	$ 2.51	2.75%	$ 2.49	2.75%	$ 2.47	2.75%	$ 2.55
TCA	$ 0.01	$ 3.04	$ 0.01	$ 3.04	$ 0.01	$ 3.04	$ 0.01	$ 3.04	$ 0.01	$ 3.04	$ 0.01	$ 3.04	$ 0.01	$ 3.04
CACJ Adjustment	$ 0.00	$ 2.66	$ 0.00	$ 2.66	$ 0.00	$ 2.66	$ 0.00	$ 2.66	$ 0.00	$ 2.66	$ 0.00	$ 2.66	$ 0.00	$ 2.66
BHEAP Funding Fee	0.51	$ 0.51	0.51	$ 0.51	0.51	$ 0.51	0.51	$ 0.51	0.51	$ 0.51	0.51	$ 0.51	0.51	$ 0.51
EGCRR*	0	$ -	0	$ -	0	$ -	0	$ -	0	$ -	0	$ -	0.00579	$ 3.47
CEPR	0.00%	$ -	0.00%	$ -	0.71%	$ 0.69	0.71%	$ 0.67	0.71%	$ 0.66	0.71%	$ 0.65	0.71%	$ 0.68
EASBC	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Monthly Bill Calculations		$ 97.73		$ 95.46		$ 100.29		$ 97.27		$ 96.48		$ 95.70		$ 102.53

*EGCRR terminates the end of March 2024, for purposes of historic and projected bill comparisons, 2022 -2023 bills have Storm Uri surcharges.

Black Hills 2023-2026 RES Plan – Management of Donated CSG Subscriptions

For the minimum 500 kW of donated subscriptions within the Company's 1.5 MW Income-Qualified ("IQ") Standard Offer Community Solar Garden ("CSG") offering, the Company commits to the following:

1. The Company will reserve donated subscriptions for IQ residential customers who are directly responsible for their bill (*i.e.*, not residential meters with a housing authority as the account holder, and not customers of any other rate class).
2. The Company will target customers from its Black Hills Energy Affordability Program ("BHEAP") waiting list for this offering, and not customers who are already enrolled in BHEAP.
3. Should a customer who is not on the BHEAP waiting list express interest in this offering, the Company will engage a third-party for the purpose of income verification of the customer.
4. The Company will engage with customers with donated subscriptions to ensure such customers are aware of: (1) their enrollment in the CSG; (2) when they can expect to see credits on their bill; (3) the expected level of bill savings; and (4) a phone number they can call with questions.
5. The Company will endeavor to size each individual CSG subscription appropriately with the purpose of equitably distributing the benefits and with the goal of achieving an affordable bill for each customer.
    a. The minimum subscription size shall be approximately 100 percent of the customer's typical annual usage.
    b. The maximum subscription size will be that which offsets a customer's electric bill on an annual basis, to be reserved for customers with zero income.
6. The Company will revisit subscription sizing any time a significant change to a customer's usage occurs that drives a need for a new subscription size, including but not limited to electrification of major appliances in the home, but on not less than an annual basis.
7. The Company commits to add to its Renewable Energy Standard ("RES") compliance reporting the following data on donated subscriptions, including: (1) the number of customers enrolled; (2) the total kW of donated subscriptions fulfilled; (3) the annual kWh production; (4) the total bill credits distributed; and (5) the average annual bill savings per customer.
8. The Company will work with customers who move to a new service address in an effort to keep them subscribed to the CSG first, before replacing them with a new subscriber.
9. The Company will report on its progress on each of the factors set forth herein in its annual RES reporting.