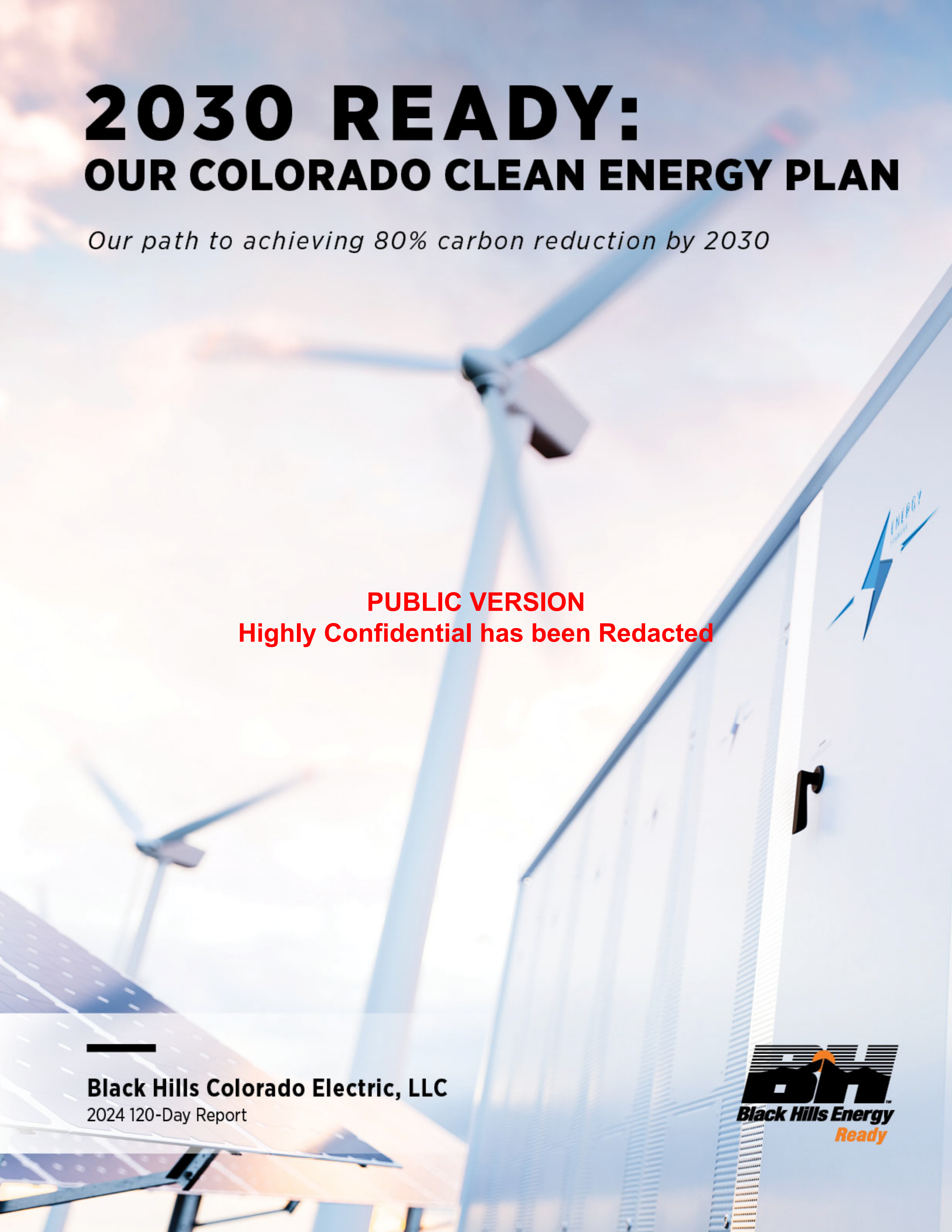
2030 READY:
OUR COLORADO CLEAN ENERGY PLAN

Our path to achieving 80% carbon reduction by 2030



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Black Hills Colorado Electric, LLC
2024 120-Day Report

Black Hills Energy Ready

Table of Contents

1:	EXECUTIVE SUMMARY:	6
1.1:	2030 READY PREFERRED PORTFOLIO OVERVIEW:	6
1.2:	2030 READY RFP BID EVALUATION OVERVIEW:	9
1.3:	PREFERRED PORTFOLIO BIDS:	10
1.3.1:	BID 248-02 150 MW WIND FACILITY:	10
1.3.2:	BID 114-05A 200 MW SOLAR FACILITY:	11
1.3.3:	BID 248-19 50 MW BATTERY STORAGE FACILITY:	11
1.4:	PREFERRED PORTFOLIO BACKUP BIDS	12
1.4.1:	WIND BACK-UPS	13
1.4.2:	SOLAR BACK-UPS	13
1.4.3:	BATTERY STORAGE BACK-UPS	14
1.5:	RISK ANALYSIS	14
1.6:	COST RECOVERY	16
1.7:	INDEPENDENT EVALUATOR	17
1.8:	NEXT STEPS	17
1.9:	EXECUTIVE SUMMARY CONCLUSION	17
2:	2030 READY CLEAN ENERGY PLAN INTRODUCTION	19
2.1:	2022 ELECTRIC RESOURCE PLAN OVERVIEW (PROCEEDING NO. 22A-0230E)	19
2.2:	2030 READY RFP OVERVIEW	21
3:	2030 READY COMPETITIVE SOLICITATION	24
3.1:	SEPARATION POLICY	24
3.2:	ISSUANCE OF 2030 READY RFP	24
3.3:	2030 READY RFP WEBSITE AND BIDDER COMMUNICATION	24
3.4:	PRE-BID CONFERENCES	25
3.5:	MODELING INPUTS AND ASSUMPTIONS	25
3.5.1:	INFLATION REDUCTION ACT	30

3.6:	FINAL BID CRITERIA	31
3.7:	2030 READY SOLICITATION	32
3.8:	2030 READY BIDS	32
3.8.1:	SOLAR (PV) BIDS	33
3.8.2:	SOLAR (PV) WITH STORAGE BIDS	34
3.8.3:	WIND BIDS	34
3.8.4:	STORAGE (STANDALONE) BID	34
3.8.5:	OTHER BIDS	34
3.8.6:	SECTION 123 RESOURCE BIDS	34
3.8.7	INITIALLY ELIMINATED BIDS	35
3.9:	30-DAY REPORT	36
3.10:	THIRD-PARTY TRANSMISSION OPPORTUNITIES:	36
4:	2030 READY BID EVALUATION	37
4.1:	STEP 1 – INITIAL ELIGIBILITY SCREENING	38
4.2:	STEP 2 –TRANSMISSION ASSESSMENTS AND INITIAL ECONOMIC EVALUATION	38
4.2.1:	TRANSMISSION ASSESSMENT	39
4.2.2:	INITIAL ECONOMIC EVALUATION	40
4.2.2.1:	WIND AND SOLAR INTEGRATION COST ADDERS	41
4.3:	STEP 3 – NON-ECONOMIC ANALYSIS	42
4.4:	STEP 4 – BID ANALYSIS BASED ON ENERGY RESOURCE ZONES	42
4.5:	STEP 5 – PORTFOLIO ANALYSIS OF BIDS	42
4.5.1:	NOTIFICATION OF ADVANCEMENT TO COMPUTER-BASED MODELING	43
4.5.2:	COMPUTER-BASED MODELING AND PORTFOLIO ANALYSIS	43
4.5.3:	CAPACITY EXPANSION AND PRODUCTION COST MODELING	44
4.6:	STEP 6 – SELECTION PROCESS	45
4.7:	CLEAN ENERGY PLAN GUIDANCE AND VERIFICATION WORKBOOKS	45
4.8:	CDPHE PHASE I VERIFICATION WORKBOOK REVIEW	46
5:	BID EVALUATION RESULTS	47

5.1:	**PORTFOLIO ANALYSIS**	**47**
5.2:	**PREFERRED PORTFOLIO ANALYSIS**	**51**
5.3:	**2030 READY PREFERRED PORTFOLIO**	**54**
5.4:	**SENSITIVITY ANALYSIS**	**57**
5.5:	**PREFERRED PORTFOLIO BIDS:**	**58**
5.5.1:	**BID 248-02 150 MW WIND FACILITY**	**58**
5.5.2	**BID 114-05A 200 MW SOLAR FACILITY**	**60**
5.5.3:	**BID 248-19 50 MW BATTERY STORAGE FACILITY**	**61**
5.6:	**REASONABLE COST OF UTILITY OWNERSHIP**	**62**
5.7:	**BACK-UP BIDS**	**63**
5.7.1:	**WIND BACK-UP BID**	**64**
5.7.2:	**SOLAR BACK-UP BIDS**	**65**
5.7.3:	**BATTERY STORAGE BACK-UP BID**	**65**
5.8:	**ALTERNATIVE PORTFOLIO OPTIMIZATIONS**	**66**
6:	**COST RECOVERY**	**67**
6.1:	**CLEAN ENERGY PLAN LEGISLATIVE COST RECOVERY FRAMEWORK**	**67**
6.2:	**PHASE I SETTLEMENT AGREEMENT- COST RECOVERY OPTIONS**	**67**
6.2.1:	**CEP ADDITIONAL COST**	**69**
6.2.2:	**COST RECOVERY OPTIONS**	**69**
6.3:	**PROPOSED COST RECOVERY**	**71**
6.3.1:	**CLEAN ENERGY PLAN RIDER (“CEPR”)**	**71**
6.3.2:	**RENEWABLE ENERGY STANDARD ADJUSTMENT (“RESA”)**	**71**
6.3.3:	**ELECTRIC COST ADJUSTMENT (“ECA”)**	**72**
6.3.4:	**PERFORMANCE INCENTIVE MECHANISM (“PIM”)**	**73**
6.3.5:	**ESTIMATED BILL IMPACT**	**73**
7:	**CONCLUSION**	**75**

List of Appendices

APPENDIX A – HIGHLY CONFIDENTIAL	BID EVALUATION SCORECARD
APPENDIX A - PUBLIC	BID EVALUATION SCORECARD
APPENDIX B – HIGHLY CONFIDENTIAL	BEST VALUE EMPLOYMENT METRICS
APPENDIX B – PUBLIC	BEST VALUE EMPLOYMENT METRICS
APPENDIX C	STANDARDS OF CONDUCT
APPENDIX D	SAMPLE BID ADVANCEMENT, REJECTION NOTIFICATION
APPENDIX E	EXPANSION PLANS FOR ALL PORTFOLIO BIDS
APPENDIX F – HIGHLY CONFIDENTIAL	NON-ECONOMIC SCORECARD
APPENDIX F – PUBLIC	NON-ECONOMIC SCORECARD
APPENDIX G – CONFIDENTIAL	HITACHI FALL 2022 REFERENCE CASE
APPENDIX G – PUBLIC	HITACHI FALL 2022 REFERENCE CASE
APPENDIX H	E3 TECHNICAL REPORT
APPENDIX I	LOAD AND RESOURCE BALANCES
APPENDIX J	AIR POLLUTION CONTROL VERIFICATION WORKBOOKS
APPENDIX K1-4- HIGHLY CONFIDENTIAL	COST RECOVERY SCENARIOS 1-4
APPENDIX K1-4 – PUBLIC	COST RECOVERY SCENARIOS 1-4
APPENDIX K5-6 – HIGHLY CONFIDENTIAL	REVENUE REQUIREMENT MODELS
APPENDIX K5-6 – PUBLIC	REVENUE REQUIREMENT MODELS
APPENDIX L	DI COMMUNITY BID MAP

1: Executive Summary:

Black Hills Colorado Electric, LLC ("Black Hills" or the "Company") is pleased to present this 120-Day Report, which is the culmination of a three-year process that began in 2021 when the Company announced[1] it would file a Clean Energy Plan pursuant to Senate Bill 19-236 ("SB 19-236"), codified in § 40-2-125.5, C.R.S. This 120-Day Report summarizes the process and results of the 2022 Electric Resource Plan ("ERP") and Clean Energy Plan ("CEP") (collectively, the "2030 Ready Plan" or the "Plan") to the Colorado Public Utilities Commission ("Commission").

Our 2030 Ready Preferred Portfolio provides a long-term outlook for a clean energy future. As an early leader in Colorado, transitioning away from coal combustion generation and toward clean energy resources through the Peak View and Busch Ranch wind facilities, Black Hills' 2030 Ready Plan is built upon years of phased-in renewable generation developments that will assist the Company in meeting and exceeding the State of Colorado's greenhouse gas emission goals while supporting the continued reliability and resiliency of our system.

Leadership in emissions reduction is nothing new for Black Hills – we retired our last Colorado coal plant in 2013, becoming the first electric utility fleet in Colorado to be coal-free. Over the past ten years, the Company has replaced its emission-intensive coal plants with lower emission natural gas generation and wind generation while maintaining system safety and reliability. Our customers value renewable energy, and we are proud our energy supply is one of the cleanest in the state, powered essentially by 100 percent natural gas and renewable energy.

Black Hills has a flexible and relatively new generation fleet, enabling the Company to reduce its greenhouse gas emissions in a phased-in approach, adding low- and no-emissions generation resources in a prudent and responsible manner. Because the Company has already transitioned a significant portion of its fleet to low-emission resources, the Company does not need to retire large portions of its generation resources.

1.1: 2030 Ready Preferred Portfolio Overview:

Our 2030 Ready Preferred Portfolio meets and exceeds the State's emission reduction target of 80% by 2030 by achieving an emission reduction of 89% by 2030. Due to the highly competitive bid process and support from the Inflation Reduction Act ("IRA"), our Preferred Portfolio's Net Present Value (NPV) Revenue Requirement is less than originally estimated, providing $595 million of savings to customers. Furthermore, the Company has thoughtfully crafted a cost recovery proposal that result in bill stability through 2030. While customers will see a new surcharge on their bill beginning in 2025, the Company is proposing to reduce the Renewable Energy Standard Adjustment surcharge, and the additional renewable energy will displace natural gas cost resulting in a net neutral impact to customer bills through 2030.

[1] See HE 101, Attachment NAW-1 Black Hills CEP Notice to AQCC.

Our 2030 Ready Preferred Plan consists of a balance of third-party owned Independent Power Producers ("IPP") and locally sited utility owned projects that provide economic development in Southern Colorado. Our 2030 Ready Preferred Plan adds geographic diversity and introduces resource diversity to our generation resources. There are no surprises with this resource selection as it is consistent with the Phase I Settlement Agreement's indicative resource acquisitions and delivers NPV cost savings.

Our 2030 Ready Preferred Plan will provide approximately $330 million of economic development impact to Colorado. All projects selected are located in Colorado, with two projects located in Pueblo County that provide approximately $56 million of local economic development impact.

Our 2030 Ready Preferred Plan consists of a 150 MW wind project (Bid 248-02) located in Kit Carson County, a 200 MW solar project (Bid 114-05a) located in Pueblo County, and a 50 MW battery storage project (Bid 248-19) located in Pueblo County.

Figure 1-1 below is a summary of the Preferred Plan resource acquisition. Figure 1-2 is a snapshot of the Company's transition to a clean energy future, and Figure 1-3 shows the Company's changing resource mix from year 2022 to year 2030 providing approximately 75% clean renewable energy by 2030. Finally, Figure 1-4 is a map depicting the locations of the Preferred Portfolio.

FIGURE – 1-1: PREFERRED PLAN RESOURCE ACQUISITION SUMMARY

Resource	Phase I: Settlement Agreement	Phase II: Preferred Portfolio	Location (County)	Contract Type	Term / Useful Life
Wind	100 MW	150 MW	Kit Carson	PPA	20 Years
Solar	200 - 250 MW	200 MW	Pueblo	BTA	30 Years
Storage	50 MW	50 MW	Pueblo	BTA	20 Years
Total	~400 MW	400 MW			
Total NPV (2021 $MM)	1,567	972			
% Emissions Reductions from 2005	80%	89%			

FIGURE 1-2: EMISSIONS REDUCTIONS

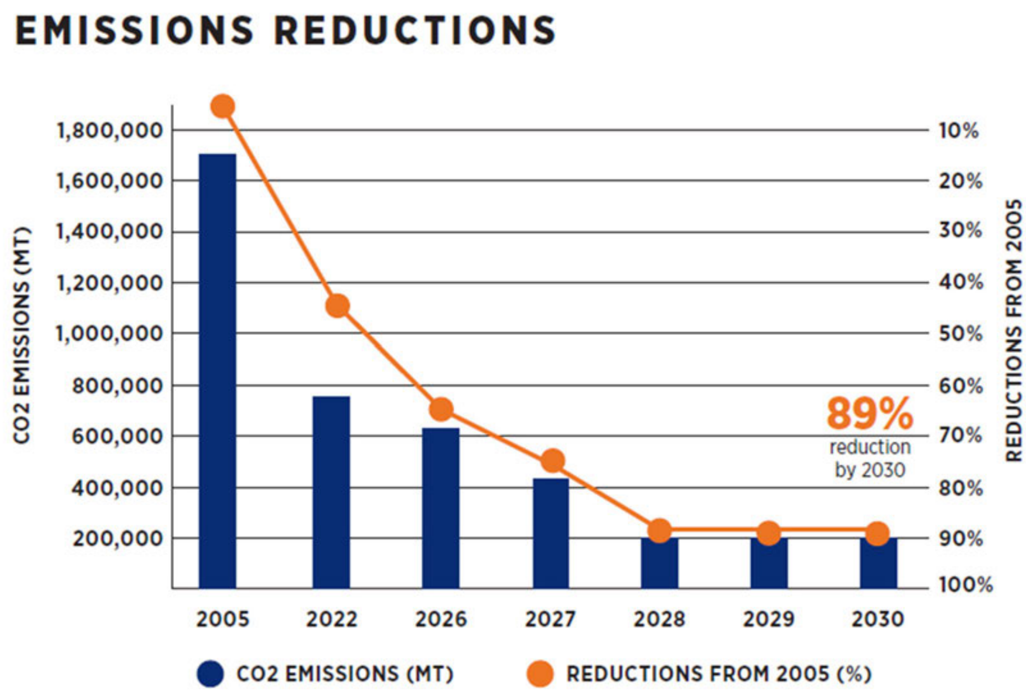


FIGURE 1-3: ENERGY MIX

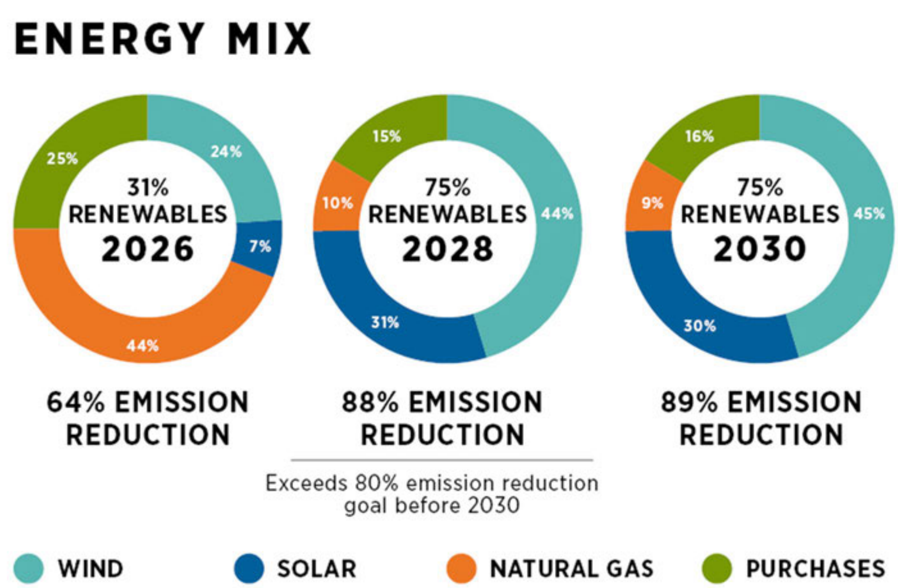
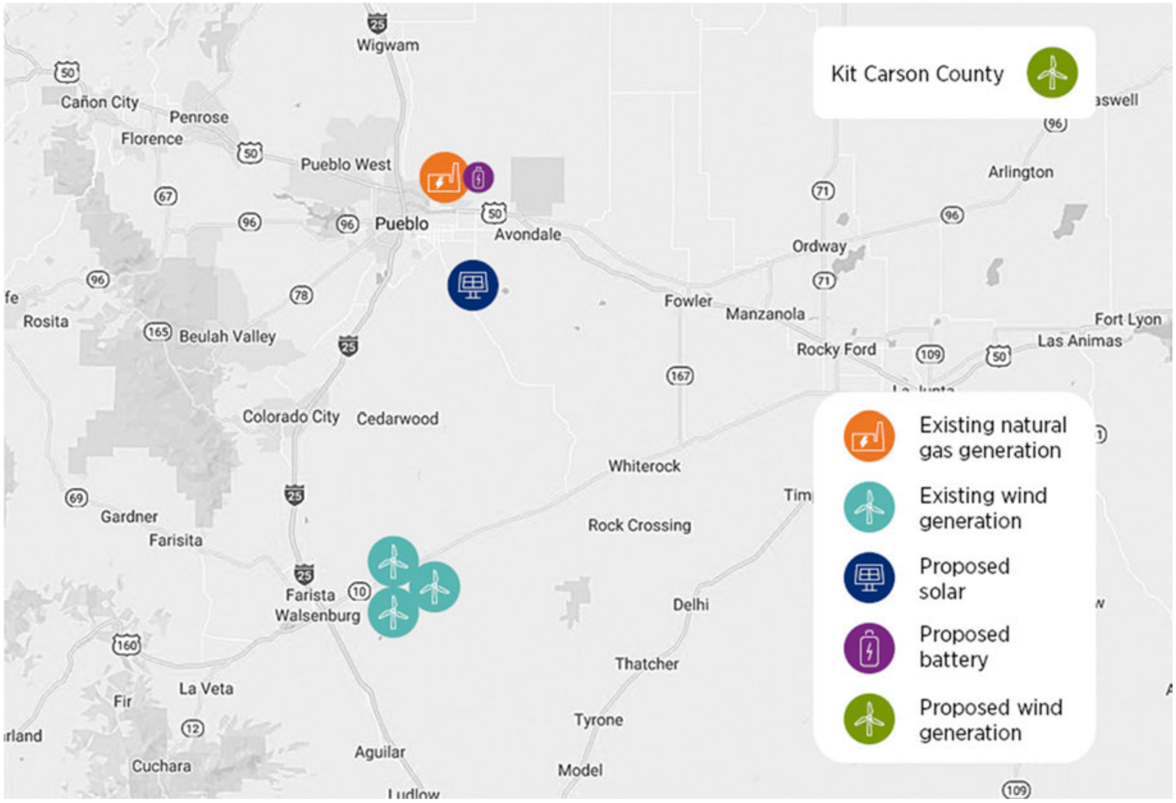


FIGURE 1-4: GENERATION RESOURCE MAP



1.2: 2030 Ready RFP Bid Evaluation Overview:

The Company is very pleased with the robust response to the 2030 Ready RFP, receiving a higher number of bids than any previous RFP. The Company received 113 bids from 23 unique bidders. The responses included a selection of resources at varying sizes, technology types, and locations. The bidders offered a range of contracting options including PPAs, build-transfer, and PPA/build-transfer offers. The PPA offers included levelized pricing through the entire term of the PPA, as well as escalating pricing. In addition, several bidders offered alternative bids with varying commercial operation dates. Commercial operation dates ranged from 2026 to 2030. The bid evaluation process included both economic and non-economic components, with heavier weighting of economic evaluation criteria. After conducting the non-economic analysis, the Company combined the economic and non-economic scores and ranked bids within each resource type category to determine which bids to advance to computer-based modeling. A total of 49 bids advanced to the computer-based capacity expansion modeling, which was performed by Energy and Environmental Economics ("E3"). In partnership with E3 and the Independent Evaluator, the Company conducted extensive stress testing by validating and testing the results of the Preferred Portfolio. We completed six different portfolio scenarios as outlined in the Settlement Agreement. The entire bid evaluation process was overseen by the Independent Evaluator.

1.3: Preferred Portfolio Bids:

After extensive modeling, testing, and analyzing the results from the computer-based capacity expansion process, the Company selected a Preferred Portfolio that consists of three projects: Bid 248-02 150 MW Wind Facility, Bid 248-19 Battery Storage, and Bid 114-05A Solar facility ("Preferred Bids"). This portfolio of bids will allow the Company to achieve the goals established in the Company's Phase 1 CEP process. A description of each bid proposal is presented below.

1.3.1: Bid 248-02 150 MW Wind Facility:

Bid 248-02 is a 150 MW wind facility located in Kit Carson County near Burlington Colorado built by a developer with significant experience. This location will add geographic diversity to the Company's system to support reliability, as the Company has no generation capacity in this portion of the state. This bid was highly competitive and was consistently selected during the capacity expansion modeling, showing up in three of the six portfolio scenarios. Table 1-1 and 1-2 below provide a summary of the bid and its economic and non-economic scorecard and rank.

TABLE 1-1- BID 248-02 SUMMARY

Bid No.	Bidder Company	Project Name	Technology	Location	Nameplate Capacity (MW)	COD Year	Contract Type
248-02	[redacted]		Wind	Kit Carson	150	2027	PPA

TABLE 1-2: BID 248-02 SCORECARD

Bid No.	Economic Score	Non-economic Score	Total Score	Rank
248-02	[redacted]			

In addition to the Company's economic assessment, the Company performed an assessment of economic development benefits of this project by using the IMPLAN software. The Company estimates the economic impact to be $146 million. Hundreds of construction jobs will be needed to build the facility. In addition, the ongoing operations and maintenance of the facility will facilitate additional job growth. The local taxing authorities will also see significant benefits.

1.3.2: Bid 114-05a 200 MW Solar Facility:

Bid 114-05a is a 200 MW solar facility located in Pueblo County built by a developer with significant experience. This facility will add resource diversity to the Company's generation fleet, as the Company currently has no large-scale solar resources. This bid was highly competitive and was consistently selected during the capacity expansion modeling, showing up in five of the six portfolio scenarios. Table 1-3 and 1-4 below provide a summary of the bid and its economic and non-economic scorecard and rank.

Table 1-3 - Bid 114-05a Summary

Bid No.	Bidder Company	Project Name	Technology	Location	Nameplate Capacity (MW)	COD Year	Contract Type
114-05a	[redacted]		Solar	Pueblo	200	2026	BTA

Table 1-4: Bid 114-05a Scorecard

Bid No.	Economic Score	Non-economic Score	Total Score	Rank
114-05a	[redacted]			

In addition to the Company's economic assessment, the Company performed an assessment of economic development benefits of this project by using the IMPLAN software. Bidder 114 estimates the economic impact to be $9 million, with hundreds of construction jobs needed to build the facility. In addition, the ongoing operations and maintenance of the facility will facilitate additional job growth. The local taxing authorities will also see significant benefits. While this project was ranked second in the overall scorecard it was consistently selected among the least cost resources in the capacity expansion modeling in five of the six portfolios studied.

1.3.3: Bid 248-19 50 MW Battery Storage Facility:

Bid 248-19 is a 50 MW battery storage facility located in Pueblo County built by a developer with significant experience. This project will add resource diversity to the Company's system to support reliability, as the Company currently has no large battery storage resources in its generation fleet. Table 1-5 and 1-6 below provide a summary of the bid and its economic and non-economic scorecard and rank.

TABLE 1-5 - BID 248-19 SUMMARY

Bid No.	Bidder Company	Project Name	Technology	Location	Nameplate Capacity (MW)	COD Year	Contract Type
248-19	[redacted]		Energy Storage	Pueblo	50	2027	BTA

TABLE 1-6: BID 248-19 SCORECARD

Bid No.	Economic Score	Non-economic Score	Total Score	Rank
248-19	[redacted]			

In addition to the Company's economic assessment, the Company performed an assessment of economic development benefits of this project by using the IMPLAN software. The Company estimates the economic impact to be $32 million. In addition, the ongoing operations and maintenance of the facility will facilitate additional job growth. The local taxing authorities will also see significant benefits. [redacted]

1.4: Preferred Portfolio Backup Bids

Due to the successful outcome of the 2030 Ready RFP, the Company is pleased to present several back-up bids, in the event the Preferred Bids fail. The Company believes it is important to receive Commission approval of back-up bids because there is a risk that the Preferred Bid fails to perform or otherwise has an unsuccessful process to negotiate an agreement. In this circumstance, the Company could then replace the Preferred Bid with the first recommended back-up bid. If the first back-up similarly fails, then the Company could then replace that bid with the back-up bids. This approach was approved by the Commission in Phase I.[2]

The Company's approach to recommending the back-up bids is to present the next most competitive bids by resource type. Because of the high competitiveness of the bids, the Company requests that acquisition of any

[2] The Settlement Agreement (Hearing Exhibit 118) provides in Paragraph 14 that "[t]he 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."

of the recommended bids (i.e., Preferred Bids and back-up bids) be approved as an appropriate outcome to further the public interest as the backup bids will still allow the Company to achieve the clean energy plan goals.

Commission approval of the recommended back-up bids will assist the Company in the negotiation process with the Preferred Bids, and will provide necessary assurance that if any of the Preferred Bids fail the Company can acquire appropriate back-up resources.

1.4.1: Wind Back-Ups

The Company is proposing one back-up bid to its 150 MW preferred wind bid. To mitigate the transmission risks described below with the preferred wind bid, the Company is recommending a solar backup bid. Bid 248-01 is a 100 MW solar facility located in Pueblo County built by the same developer and contracting structure as the preferred wind bid. This location will add resource diversity to the Company's system to support reliability, as the Company currently has no large-scale solar resources in its generation fleet. This bid was selected in portfolio six (local economic development portfolio) and would be a suitable replacement for bid 248-01 if it is unsuccessful. Using IMPLAN, the Company estimates the economic impact of this project to be $83.5 million.

TABLE 1-7: BACK-UP WIND BIDS

Bid No.	Bidder Company	Project Name	Technology	Location	Nameplate Capacity (MW)	COD Year	Contract Type	Scorecard
248-01	[redacted]	[redacted]	Solar	Pueblo	100	2026	PPA	[redacted]

1.4.2: Solar Back-Ups

The Company has identified three back up solar bids to the preferred solar bid: Bid 223-01b + Bid 223-03b, and 190-05a. These bids represent the next highest ranked solar BTA bids that would fit within the preferred portfolio. As shown in Table 1-8, Bid 223-01b and Bid 223-03b are both 100 MW solar facilities, totaling 200 MW and thus the combination of these two bids would represent a replacement for the preferred bid if needed. Bid 190-05a is a 199 MW solar facility located in Pueblo County built by a developer with significant experience, and would also represent a replacement for the preferred bid if needed.

Table 1-8: Back-up Solar Bids

Bid Number	Bidder Company	Project Name	Technology	Location	Nameplate Capacity (MW)	COD Year	Contract Type	Scorecard
223-01b + 223-03b	[redacted]	[redacted]	Solar	Otero County	100 + 100	2028	BTA	[redacted]
190-05a	[redacted]	[redacted]	Solar	Pueblo County	199	2027	BTA	[redacted]

1.4.3: Battery Storage Back-Ups

The Company has identified one back up battery storage bid, bid 245-01. Bid 245-01 is a 50 MW battery storage facility located in Freemont County built by a developer with significant experience. This project will add resource diversity to the Company's system to support reliability, as the Company currently has no large-scale battery storage resources in its generation fleet. This bid was highly competitive and was consistently selected during the capacity expansion modeling, showing up in four of the six portfolio scenarios. [redacted]

Table 1-9: Back up Battery Storage Bids

Bid Number	Bidder Company	Project Name	Technology	Location	Nameplate Capacity (MW)	COD Year	Contract Type	Scorecard
245-01	[redacted]	[redacted]	Battery Storage	Fremont County	50	2027	PPA w/ BTA	[redacted]

1.5: Risk Analysis

As noted in the Company's RFP, risk of bids received by the Company were to be evaluated for development, technology, permitting, and transmission. Accordingly, during the course of the Bid Evaluation process, the Company employed risk-mitigation efforts. These efforts included requiring bidders to provide comprehensive information in narrative and bid specific form on a variety of risk-based issues, covering topics relevant to project development, site control, permitting, land use, transmission interconnection, tax issues, and cybersecurity. Concerning specific risk mitigation efforts, the Company required bidders to execute a site control affidavit, attesting that the bidder possesses site control, that the site is adequate for the facility, and that the bidder will obtain appropriate zoning variances/approvals before PPA execution. In addition, the Company requested bidders to provide information to confirm the continued viability of the bids and the continued ability of the bidders to perform.

Concerning storage-specific risks, [redacted]

Concerning cybersecurity, the Company worked closely with the IE to craft the appropriate cybersecurity language for inclusion in the bid application. As a result, the RFP required bidders to acknowledge compliance with all NERC and the Defense Federal Acquisition Regulations before interconnection would be permitted, and that meeting this requirement was the sole responsibility of the bidder. Bidders were required to identify if they were an affiliated entity of or procured products or services from vendors or subsidiaries/affiliates on the DFARS Exclusion List. Bidders were also required to list all vendors associated with their project that included cybersecurity components, as well as contact information for each of those vendors.

The Company hosted a Pre-Bid Webinar Conference on August 17, 2023, with a follow up Question and Answer Webinar for all bidders to attend on September 14, 2023. During these conferences, the Company stressed the importance of the cybersecurity vendor review process that would be conducted, guidelines for this process, and the need for all bidders to provide the required information included in the bid application to do so in a timely manner.

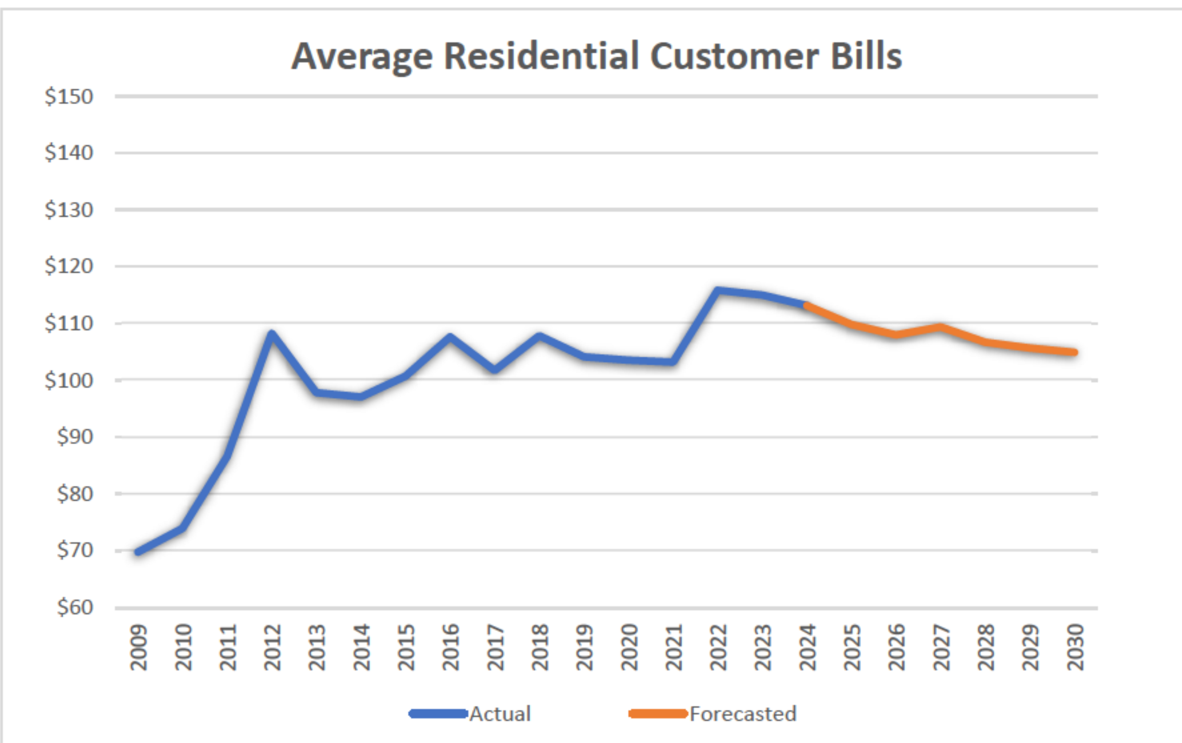
Additionally, bidders who advanced to computer-based modeling were reminded of this requirement in their advancement notification on December 19, 2023. The IE further stressed this requirement of the RFP process in a message to all remaining bidders on February 27, 2024. Throughout this stage, bidders were notified of outstanding responses for necessary vendor information. As information was produced, the Company's IT Risk Management team worked in partnership with a Third-Party IT Risk department to assess the cyber-supply chain risk for each bidder's solutions. To accomplish this analysis, the team uses SOC2 Type2 or other audited statements and attestations provided by the original manufacturer/maker of the various cyber assets detailed in the bidding process.

The Company also believes it is important to reduce the likelihood of selected bids failing. To that end and in collaboration with the IE, the Company issued a notice on March 27, 2024 to all remaining bidders requesting they confirm 1) if their bid is selected they are prepared to move forward with contracting and 2) that they will be able to post the required security once a contract is executed. Bidders for the recommended bids in all portfolios confirmed they will proceed as required if selected.

1.6: Cost Recovery

The Company has thoughtfully designed a cost recovery proposal the minimizes the customer bill impacts associated with this Clean Energy Plan. By minimizing cost and utilizing the CEP's cost recovery statutory framework, the Company is forecasting a slight decline in residential customer bills through 2030. The Company performed a bill impact analysis that compares currently effective rates and rates that will be in place on January 1, 2025, using a 1.5 percent reduced RESA surcharge, and an ECA based on the projections used for modeling. While customers' bills will increase on January 1, 2025 when the new CEPR begins collections at 1.5 percent, there will also be bill reductions as a result of the expiration of the Extraordinary Gas Cost Recovery Rider (which is recovering Winter Storm Uri costs) and lower projected ECA costs. Compared to average bills based on rates effective March 1, 2024, the Company is projecting a net reduction to the average residential monthly bill of $5.16, or -4.56 percent, on January 1, 2026. Ultimately, residential customers will see a total average monthly bill decrease of 7.28 percent by 2030 compared to current rates. The graph below represents the average residential monthly bill through 2030, which assumes no rate adjustments from other ongoing or future proceedings. This chart demonstrates the Company's ability to maintain customer bill stability while increasing our renewable energy per State statute. Importantly, this analysis does not consider other potential changes to other surcharges or base rates, which can fluctuate from over time. Rather, this bill impact analysis examined the effects this clean energy plan has on the average residential customer bill.

FIGURE 1-6 AVERAGE RESIDENTIAL CUSTOMER BILL



1.7: Independent Evaluator

Pursuant to the Commission Rule 3612, the Company has retained Accion Group, LLC ("Accion")[3] as an Independent Evaluator ("IE") to observe the Company's bid solicitation and evaluation process and to report back to the Commission on the fairness of the process.

Black Hills also retained Accion Group to host the Black Hills 2030 Ready RFP website, available https://blackhills2030ready.accionpower.com ("2030 Ready RFP Website"), through which the entire solicitation process was conducted. All communications with bidders, including bidder responses to the RFP, bidder questions, Company answers and additional documentation (e.g.., notification of bid advancement to computer-based modeling) was completed through the 2030 Ready RFP Website.

Black Hills made appropriate Company staff available to work with the IE to answer questions and discuss issues that arose during the course of the competitive solicitation process. Black Hills consulted with the IE on a number of occasions throughout the solicitation process. The Company appreciates the partnership and consultant support the IE provided as the Company addressed various issues with the bids.

Consistent with the procedural schedule approved in this proceeding by Decision No. C23-0193, the IE will file a report with the Commission on or before May 17, 2024, that will include their assessment and conclusions regarding the Company's solicitation and evaluation process.

1.8: Next Steps

Per Decision No. C23-0193 ("Phase I Decision"), a technical conference with stakeholders will occur on May 1, 2024. The IE will file its report on the RFP process on May 17, 2024. Intervenors then have the opportunity to file comments to this 120-Day Report on June 3, 2024. Black Hills will file its own comments and will propose a performance incentive mechanism (PIM) on June 17, 2024. Responses to the PIM proposal are due July 16, 2024. Black Hills seeks a final Commission decision no later than July 16, 2024, to provide sufficient time to finalize negotiations with bidders and ensure awarded bidders can complete projects on a timely basis.

1.9: Executive Summary Conclusion

In conclusion, the Company is pleased to present this 120-Day Report, which is the culmination of a three-year process that began in 2021 when the Company made the strategic decision to pursue the clean energy plan targets as set forth by the general assembly. The Company has selected a cost-effective and lowest risk portfolio from dozens of highly competitive bids. The 2030 RFP generated a robust response with highly competitive bids. Our 2030 Ready Preferred Portfolio meets and exceeds the State's emission reduction target of 80% by 2030 by achieving an emission reduction of 89% by 2030. The Preferred plan addresses resource

[3] Accion Group has provided IE services in the Company's last three competitive solicitations, and it has also provided IE services to PSCo.

adequacy needs while more than doubling the Company's renewable energy generation. The preferred plan supports our local community goals of increasing renewable energy and provides a substantial economic development impact. The Company has thoughtfully crafted a cost recovery proposal that results in customer bill stability through 2030 as compared to current bills. We appreciate the dozens of developers who have participated in the RFP and all the stakeholders who have helped shaped this Clean Energy Plan. We respectfully request the Commission approve our preferred plan, the backup bids, and our cost recovery proposal.

2: 2030 Ready Clean Energy Plan Introduction

This section of the 120-day report describes the 2022 Electric Resource Plan proceeding and provides background information on the Phase 1 process which led to a unanimous comprehensive Settlement Agreement that was approved by the Commission and set the foundation for the Phase II competitive resource acquisition process. This section also provides a summary of the Phase II bids the Company received.

2.1: 2022 Electric Resource Plan Overview (Proceeding No. 22A-0230E)

On May 27, 2022, Black Hills filed its 2022 Electric Resource Plan ("ERP") and 2023-2026 RES Plan in Proceeding No. 22A-0230E. The combined plans collectively were called the "2030 Ready Plan." The Company voluntarily opted into the requirements of SB 19-236 and HB 19-1261 by filing its 2030 Ready Plan as part of its commitment to achieving Colorado's ambitious clean energy and emissions reduction goals. The Company's ERP specifically was filed to meet Governor Jared Polis's 2019 roadmap to reduce greenhouse emissions by 26 percent by 2025, 50 percent by 2030, and 90 percent by 2050 as compared to 2005 levels.

In its Application requesting approval of both Plans, the Company, an early leader in transitioning away from coal combustion generation and towards clean energy resources through the Peak View and Busch Ranch wind facilities, stated that the purpose of its 2022 ERP/CEP was to provide a long-term outlook for a carbon-free future while working to provide affordable bill impacts. Black Hills' 2030 Ready Plan was modeled upon years of phased-in renewable generation projects that will assist the Company in meeting and exceeding the State of Colorado's greenhouse gas emissions goals while also supporting the continued reliability and resiliency of our system. The 2022 ERP/CEP covered a 29-year planning period from January 2022 through 2050.

After lengthy negotiations and to strike a balance that carefully aligned the Parties' broad interests while also serving the public interest, Black Hills filed a Unanimous Comprehensive Settlement Agreement on January 13, 2023. The Settlement Agreement was joined by Black Hills, Staff of the Commission ("Staff"), the Office of the Utility Consumer Advocate ("UCA"), the Board of County Commissioners of Pueblo County ("Pueblo County"), the Colorado Energy Office ("CEO"), the Colorado Independent Energy Association ("CIEA"), Western Resource Advocates ("WRA"), and the Interwest Energy Alliance ("Interwest"), City of Pueblo ("Pueblo City"), Energy Outreach Colorado ("EOC"), Walmart Inc. ("Walmart") (collectively, the "Settling Parties"), and not opposed by any party. This, along with other Settlement Agreement provisions, save over $100 million from the cost of the original ERP/CEP Direct Case. It was important to the Company that the RES Plan be designed in a way that enables compliance with both applicable requirements and legislative directives while also responsibly managing costs for customers.

While the final costs will be contingent on the bids received and what portfolio is ultimately selected in the Phase II of this Proceeding, Black Hills provided an "Attachment B" to the Settlement Agreement which outlined the estimated costs and bill impacts.

On March 22, 2023, the Commission issued Decision No. C23-0193 ("Phase I Decision") addressing the Company's Application for approval of its 2022 ERP & CEP and approving, with modifications, the Unanimous

Comprehensive Settlement Agreement. The Company issued its All-Source Solicitation Request for Proposals ("RFPs") on July 31, 2023, including a Build Transfer Agreement, Renewable Energy Purchase Agreement, a Renewable Generation and Battery Storage Energy Purchase Agreement, a Stand-Alone Battery Storage Services Agreement, and a Dispatchable Energy Purchase Agreement for non-Fossil Fuel Resources.

The Settling Parties agreed that the Commission should approve a Phase II competitive solicitation to acquire approximately 400 MW of eligible energy resources. On July 19, 2023, Black Hills filed a Revised Scope of Work Contract for Proposed IE. On July 31, 2023, by Decision No. C23-0501, the Commission granted the Company's request for approval for a revised scope of work for Independent Evaluator ("IE") Accion Group as the independent contractor for Phase II of the 2022 ERP. In addition, the RFP project website, managed by Accion, contained a list of assumptions that the Company used to complete assessments. All bidders were highly encouraged to review these assumptions prior to submitting bids.

Black Hills initiated its Phase II competitive solicitation by issuing its 2030 Ready RFP on July 31, 2023, and the bid forms were issued on August 21, 2023. Due to the robust response to the RFP, the Company sought a 60-day extension of its 120 Day Report. The Commission granted the Company's request through Decision No. C23-0807.

On November 20, 2023, Black Hills submitted its 30-Day Report to the Commission. The 30-Day Report provided an overview of the bids received in response to the 2030 Ready RFP and included the number of bids received, the identity of the bidders that submitted bids, pricing information, technology type, nameplate capacity of proposed project, estimated annual production, storage duration, proposed commercial operation date, and if the bids claimed Section 123 status.

Also, in Black Hills' 30-Day Report, the Company described the strong response to both its RFP, which included bids for a variety of eligible energy resource generation technologies with a range of proposed pricing options. The Phase II process culminates with this 120-Day Report in which Black Hills presents the results of the computer-based modeling of the actual bids and identifies a preferred portfolio that is recommended for acquisition.

As part of the 120-day Report, the Company made 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[4]. Additionally, per the Settlement Agreement, Black Hills agreed to present, as part of the 120-day Report, several cost recovery options for its Preferred Portfolio, including the total bill impacts through 2030 of each option, and identify its preferred approach.

In lieu of discovery, the Company will hold a technical conference within 14 days of filing its 120-day report. The Company is filing its 120-Day Report on the Phase II competitive solicitation on April 17, 2024 per Decision No. C23-0807, setting forth its Preferred Portfolio that includes a minimum of 80 percent emissions reductions by 2030 from 2005 levels and include SCC and SCM in the capacity expansion step of the modeling. As detailed

[4] These maps are provided in Appendix L – DI Community Bid Map.

in the Settlement Agreement, the Company agreed to provide an updated and detailed Load and Resource Balance table for its Preferred Portfolio (Portfolio 3) as part of its 120-day Report.

2.2: 2030 Ready RFP Overview

On November 20, 2023, Black Hills submitted its 30-Day Report to the Commission. The 30-Day Report provides an overview of the bids received in response to the Company's 2030 Ready RFP and includes the number of bids received, the identity of the bidders that submitted bids, pricing information, technology type, nameplate capacity of proposed projects, estimated annual production, storage duration, proposed commercial operation date, and if the bids claimed Section 123 status.

The Company assessed each of the bids individually using a well-defined six-step Bid Evaluation process. A detailed description of the Bid Evaluation process can be found below in section 4 of this report. Except as discussed in this Report, the Company's portfolio analysis generally used the same evaluation modeling tools that were used to complete the Phase I analysis, with updates to several inputs and assumptions to provide more timely and accurate modeling results.

The Company received 113 bids from 23 unique bidders in response to its 2030 Ready RFP. The responses included a selection of resources at varying sizes, technology types, and locations. The response to the RFP was robust as the Company received the highest amount of bids it has ever received. The bidders offered a range of contracting options including PPAs, build-transfer, and PPA/build-transfer offers. The PPA offers included levelized pricing through the entire term of the PPA, as well as escalating pricing. In addition, several bidders offered alternative bids with varying commercial operation dates, ranging from 2026 to 2030.

Table 2-1 below provides a summary of the types of technology that were offered. Please note that Table 2-1 represents all bids received, including bids that were determined to not be evaluated through initial screening.

Table 2-1: 2030 Ready Bids Evaluated by Technology Type

Technology	Number of Bids Evaluated	Total Nameplate Capacity
Solar (PV)	57	6,968 MW
Solar (PV) with Energy Storage	38	7,059 MW
Wind	[redacted]	
Energy Storage (standalone)		
Total	113	15,759 MW

Highly Confidential Appendix A includes the identity of the bidders that submitted bids, the levelized cost of energy ("LCOE") and levelized cost of capacity ("LCOC") calculated by Black Hills, technology type, nameplate capacity, capacity factor, estimated annual production, proposed commercial operation date, contract term, and whether the project claimed Section 123 status.

The vast majority of the projects are proposed to be constructed in Southern Colorado, within or in close proximity to the Company's service territory. Figure 2-1 shows a broad map detailing the bid locations. In addition, Figure 2-2 shows a more detailed map of the Colorado bid locations, particularly near the Company's service territory.

FIGURE 2-1: HIGH-LEVEL MAP OF BID LOCATIONS

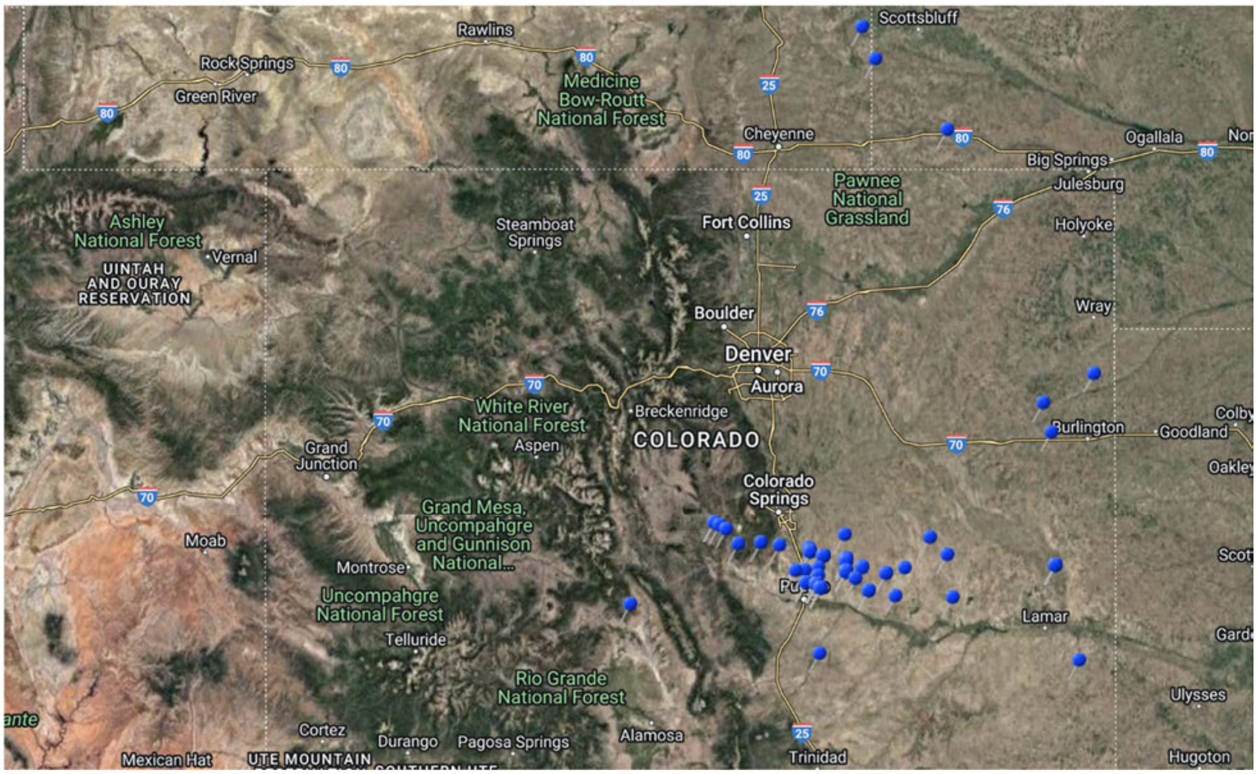
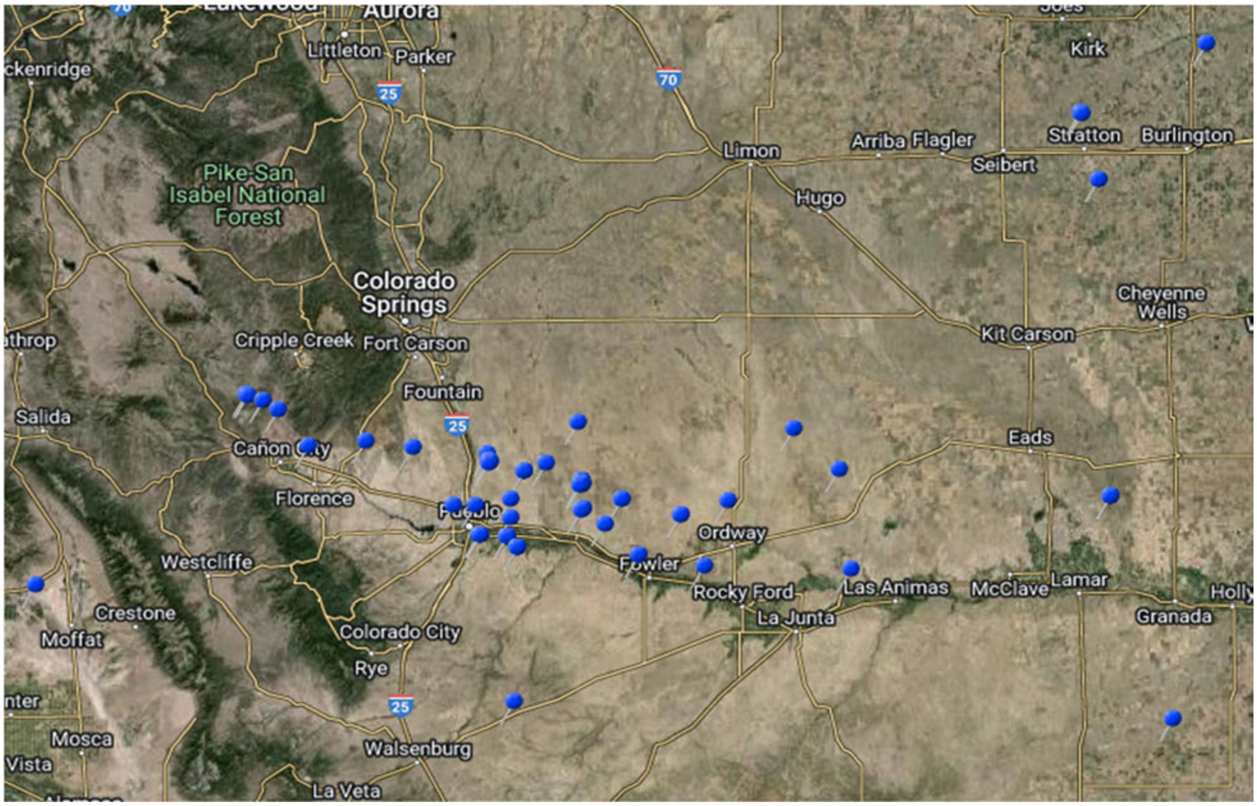


FIGURE 2-2: FOCUSED MAP OF BID LOCATIONS IN COLORADO



3: 2030 Ready Competitive Solicitation

This section of the 120-day report describes the 2030 Ready RFP (Phase II) process and the evaluation steps the Company used to select the Preferred Portfolio.

3.1: Separation Policy

In anticipation of issuing the RFP for the 2030 Ready solicitation, the Company issued a Separation Policy. This policy included detailed standards of conduct for Black Hills' employees involved in the Bid Evaluation process and employees of affiliates that worked on responses to the RFP. One affiliate of Black Hills – Black Hills Electric Generation, LLC – submitted a bid in response to the RFP. Importantly, no employees of any entity that would potentially bid into the RFP were authorized as members of the Bid Evaluation Team. Each member of the Black Hills Electric Generation, LLC Bid Team and Evaluation Team signed acknowledgement forms indicating that they had reviewed and understood the applicable standards of conduct. An example of the Standards of Conduct document that was signed by members of the Black Hills Bid Evaluation Team and the Black Hills Electric Generation, LLC Bid Team is included in Appendix C. The Company also instituted limits on its network to prevent members of the Black Hills Electric Generation, LLC Bid Team from accessing materials of the Bid Evaluation Team and vice-versa. Notably, the bid from Black Hills Electric Generation, LLC was not selected as a preferred or back-up bid.

3.2: Issuance of 2030 Ready RFP

The Company issued its 2030 Ready RFP on July 31, 2023. The RFP sought to acquire projects of up to 400 MW of eligible energy resources (as defined in C.R.S. § 40-2-124, including Section 123 Resources) and storage (stand-alone storage or storage combined with renewable energy). Bids in response to the RFP were due by 4:00 p.m. Mountain Time on October 20, 2023.

3.3: 2030 Ready RFP Website and Bidder Communication

As mentioned above, Black Hills engaged Accion Group to host the 2030 Ready RFP Website (https://blackhills2030ready.accionpower.com) where the entire solicitation process was conducted. All communication with bidders, including bidder responses to the RFPs, bidder questions, and additional documentation such as notification of bid advancement to computer-based modeling, was completed through the 2030 Ready RFP Website.

On several occasions, Black Hills consulted with the IE before responding to bidders' questions or sending notifications to bidders through the 2030 Ready RFP Website. Black Hills also posted a number of relevant documents on the Website, such as a map of relevant substations, hourly load shape detail, regulation and frequency response service costs, bid forms, and the general planning assumptions, providing further information to bidders. Importantly, the IE facilitated these communications and information sharing. The IE operated the 2030 Ready RFP Website, ensuring that all communications with bidders were overseen by the IE.

3.4: Pre-Bid Conferences

Black Hills hosted Pre-Bid Conferences by webinar on August 17, 2023, and September 14, 2023. These webinars were open to all interested parties including bidders and non-bidders. At these conferences, the Company provided background information about its 2022 ERP and the proposed 2030 Ready plan and RFP process.

During the conferences, Black Hills' staff described the Company's transmission system, the external points of interconnection, the Large Generator Interconnection Process ("LGIP"), and regulation service requirements. Black Hills also described the bid evaluation process, including economic and non-economic evaluation criteria weighting, cybersecurity vendor requirements, and discussed with bidders the proposed schedule and timeline of 2030 Ready.

The Company responded to all questions that were asked during the Pre-Bid Conferences, but also informed and encouraged the attendees to post questions on the 2030 Ready Website, which would ensure that all bidders would have access to Black Hills' responses to bidder questions. Additionally, Black Hills responded to questions bidders raised during the Pre-Bid Conference on the 2030 Ready Website. Black Hills actively monitored the Website and responded to bidders and their questions in a timely manner.

3.5: Modeling Inputs and Assumptions

The record in the 2022 ERP proceeding established the general planning assumptions that were used in Phase I of the 2022 ERP and the key inputs and assumptions that were used by the Company in evaluating proposals received through the Phase II solicitation. Black Hills' 2030 Ready RFP is premised on using many of the Commission-approved data and assumptions from the 2022 ERP, with data and assumptions updated as necessary, and using the Commission-approved modeling framework to assess impacts and select the Preferred Portfolio. These assumptions represent "base portfolio" assumptions.

For its 2030 Ready RFP, the Company has specifically updated the following assumptions from its 2022 ERP: (1) the load and resource balance; (2) fuel and market energy prices; (3) renewable integration costs; (4) model years; (5) curtailment costs; (6) renewable bid profiles; (7) replacement cost method; (8) generic resource cost assumptions for solar, wind, and battery storage; and (9) production tax credit.

Table 3-1, shown below, identifies the general planning assumptions the Company used to evaluate bids received in response to the 2030 Ready RFP. The table also identifies which 2022 ERP assumptions were revised for the 2030 Ready RFP evaluation.

TABLE 3-1: GENERAL PLANNING ASSUMPTIONS

Item	2022 ERP Assumption	Updated in Phase II	Phase II Assumption
Capacity credit for solar	See Section 6.3	No	See ERP Section 6.3
Capacity credit for wind	See Section 6.3	No	See ERP Section 6.3
Conventional and Renewable resource options considered	See Section 5.4	No	See ERP Section 5.4
Conventional resource options prices	See Section 5.4	No	See ERP Section 5.4
Renewable resource options prices	See Section 5.4	Yes	E3 provided from NREL 2023 Annual Technology Baseline
Cost of integrating renewable resources	See Section 6.1	Yes	PSCo Transmission Formula 2023 Estimate; see Section 4.2.3.1
DSM forecast	See Section 3.7	Yes	Values approved in Proceeding No. 21A-0166E
Large customer forecast	See Section 4.3.4	Yes	No changes needed; see ERP Section 4.3.4
Social costs of emissions	See Section 3.6	No, if federal Interagency Working Group publishes updates to those values prior to the issuance of the Company's Phase II	See ERP Section 3.6
Financial parameters	See Table 3-6	No	See ERP Table 3-6
General inflation rate	1.5%	If appropriate	1.5%
Load forecast	See Section 4.0	No	See ERP Section 4.0
Market prices	Confidential HAPG forecast	Yes	Confidential Hitachi 2022 Fall Reference Case, Appendix G

Item	2022 ERP Assumption	Updated in Phase II	Phase II Assumption
Natural gas prices	Confidential HAPG forecast	Yes	Confidential Hitachi 2022 Fall Reference Case, Appendix G
Existing unit operating characteristics and costs	See Table 5-1,5-2, and Appendix F	No	See ERP Table 5-1, 5-2, and Appendix F
Existing unit retirement dates	See Table 5-1, 5-2, and Appendix F	No, approved early Pueblo Diesel retirement	Pueblo Diesels retires 1/1/2026
Planning period	29 years	No	See ERP Section 3.1
Planning reserve margin	24% minimum	No, 20% as approved	20% minimum
Power purchase contracts	Varies by resource	No	Varies by resource
Resource Acquisition Period	9 years	No	See ERP Section 3.2
Seasonal firm market purchases	See Section 3.4.5	No	See ERP Section 3.4.5

Regarding these assumptions, the Company provides additional explanation in the following sections. Additional details may also be found in Appendix H, E3 Technical Report.

The Company updated its load and resource balance to include the effects of the updated DSM values approved in Proceeding No. 21A-0166E. The load and resource balance for the RAP, which includes the base load forecast and existing resources, is shown in Table 3-2. The load and resource balance for the entire Planning Period is included in Appendix I.

Table 3-2: Load and Resource Balance (2026-2030)

	2026	2027	2028	2029	2030
Peak Demand	467	468	469	470	471
DSM	19.1	19.1	19.1	19.1	19.1
Net Peak Demand	**447**	**449**	**450**	**451**	**452**
Existing Resources *					

	2026	2027	2028	2029	2030
Pueblo Diesels					
Airport Diesels	10	10	10	10	10
Rocky Ford Diesels	10	10	10		
PAGS LMS100 1	90	90	90	90	90
PAGS LMS100 2	90	90	90	90	90
Busch Ranch I Ownership**	2.0	2.0	2.0	2.0	2.0
Peak View Ownership**	8.3	8.3	8.3	8.3	8.3
PAGS LM6000	40	40	40	40	40
Total Resources	**250**	**250**	**250**	**240**	**240**
Contract Purchases*					
PAGS CC PPA	200	200	200	200	200
Busch Ranch I PPA**	2.0	2.0	2.0	2.0	2.0
Busch Ranch II PPA**	8.1	8.1	8.1	8.1	8.1
Total Purchases	**210**	**210**	**210**	**210**	**210**
Total Resources and Purchases	**460**	**460**	**460**	**450**	**450**
20% Reserve Margin (MW)	89	90	90	90	90
Total Capacity Requirement (peak plus reserves)	**536.4**	**538.8**	**540.0**	**541.2**	**542.4**
Total Resources minus Total Capacity Requirement					
In MW	**(76.1)**	**(78.5)**	**(79.7)**	**(90.9)**	**(92.1)**

	2026	2027	2028	2029	2030
As a percentage	**(14.2%)**	**(14.6%)**	**(14.8)**	**(16.8%)**	**(17.0%)**
Notes:					
*Summer rated capacities shown.					
**13.57% of all existing wind resources count as accredited capacity.					

Model years were adjusted to reflect each year that bids can come online beginning in 2026-2030. Generic resources were allowed to be selected in 2031, 2035, 2040, 2045, and 2050.

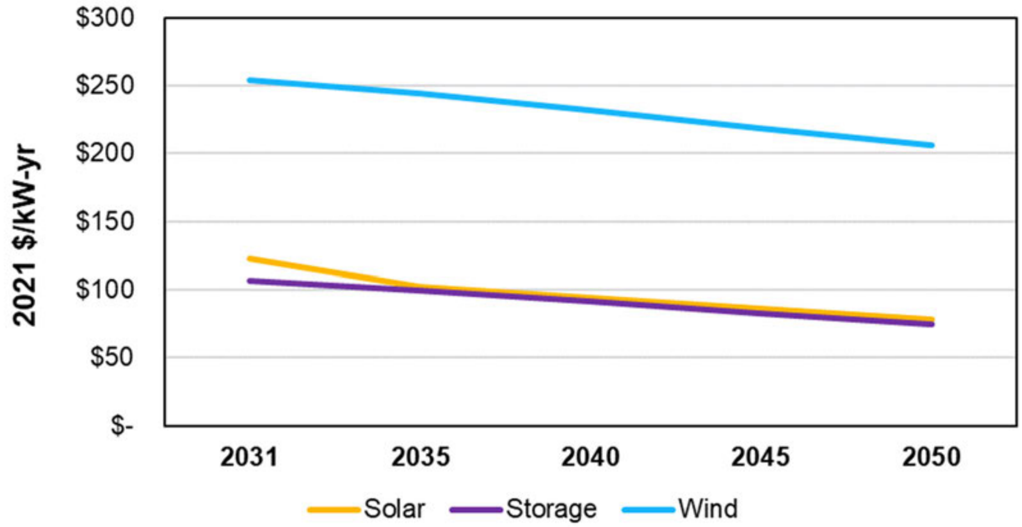
As requested on the pricing forms of the RFP documents, curtailment costs, if provided by the bidder, were incorporated into the bid analysis. Additionally, bidder renewable profiles were mapped to an electric resource zone (ERZ) profile from Phase I and adjusted by the bid's capacity factor.

The replacement cost method is the cost to replace the bid resources beyond their contract term or economic lifetime. The replacement cost for all bids was quantified as the median price of all short-listed bids of the same resource type. Both the replacement chain and annuity methods were evaluated in the portfolio analysis, as agreed to in Settlement. The Company believes the replacement chain method is the most reasonable and accurate as it avoids under-estimating the potential cost of replacement generation, which could have the effect of making shorter-term PPAs appear more cost effective as part of the modeling process.[5]

Generic renewable resource price forecasts followed the cost reduction trajectories from the 2023 NREL Annual Technology Baseline for each resource type. These cost curves were adjusted to align with the median prices of the short-listed bids of the same resource type to ensure generic pricing was calibrated to the best available pricing for the system. The generic resource price forecasts are provided in Figure 3-3 below.

[5] The Company addressed this in the Rebuttal Testimony of Amanda Thames, Hearing Exhibit 112, Rebuttal Testimony of Amanda M. Thames, at 25: 12-19, but through course of settlement negotiations the Company agreed to run a sensitivity around the annuity method.

TABLE 3-3: GENERIC RESOURCE REAL LEVELIZED COSTS



Source: E3 Technical Appendix

Production tax credits were adjusted to reflect the Inflation Reduction Act, which is covered in more detail in Section 3.5.1. Additional modeling details can also be found in Appendix H, E3 Technical Report.

3.5.1: Inflation Reduction Act

The Inflation Reduction Act of 2022 P.L. 117-169 ("IRA" or the "Act") enacted provisions which make utility ownership of renewable projects more cost competitive. The provisions include options to claim production tax credits ("PTCs") on solar facilities, investment tax credits ("ITCs") for energy storage which include an election to opt out of the normalization rules, and the ability to sell tax credits to unrelated parties for cash ("IRA Transferability"). The IRA also established 10% credit ITC and PTC adders for projects constructed in Energy Communities and for projects built from minimum levels of domestic content. Several projects that were bid are in Energy Communities, making them eligible for the credit adder. Qualifying for the domestic content adder is less certain and the Company assumed no bids would qualify.

The tax normalization rules require utility ITCs to be amortized over the regulatory life of the facility. Amortization to customers cannot start until the ITC begins to reduce the utility's cash tax liability. However, PTCs are not required to be normalized and may be passed to customers as they are generated regardless of the utility's tax appetite.

The option to now elect PTCs for solar facilities allows tax credits to be passed to customers immediately as they are generated. The election to opt out of the normalization rules for energy storage ITCs also allows the benefits to be passed to customers as generated and over any period a Commission deems appropriate.

The IRA Transferability provisions allow Black Hills to sell the ITCs and/or PTCs generated on company-owned projects to a third party for cash without the need to enter complex tax equity partnerships. Black Hills has current net operating loss and tax credit carryforwards which will not allow the Company to timely monetize ITCs and PTCs that will be generated on Company-owned projects. When a tax credit generated is unused in the current tax year it results in a tax credit carryforward that can offset taxable income in future years. This carryforward is recorded as a deferred tax asset ("DTA") on the Company's books.

PTCs may be passed through to customers as they are generated. If the benefit is passed through to customers before the Company reduces its tax liability, the DTA is included in rate base until such time it is monetized.

The modeling approach for Phase II assumes PTCs are claimed on solar projects and passed to customers as they are generated over 10 years and ITCs on energy storage with an election out of the normalization rules. The energy storage ITCs are modeled to be passed to customers over 10 years, rather than over the regulatory life of the facility.

The modeling also assumes the sale of all ITCs and/or PTCs using the IRA Transferability provisions for all Company-owned eligible resources. The IRA Transferability provisions eliminate the DTA associated with unused PTCs. Customers benefit from not paying the carrying cost of the DTA while receiving the immediate benefit of the tax credits as they are generated net of the transfer discount and related transaction costs. The modeling used for Phase II assumes all tax credits are sold at a price determined by multiplying [redacted] times the tax credit to be sold. The Company developed the estimated transfer price based on discussion with its peers, advisors, and publicly disclosed sales.

3.6: Final Bid Criteria

Prior to issuing the 2030 Ready RFP, the Company established its final bid evaluation criteria. Bids were evaluated on two primary components: (1) economic evaluation criteria and (2) non-economic evaluation criteria. Of the entire bid evaluation criteria, the economic analyses constituted 75% of the evaluation and the remaining 25% was determined using a non-economic analysis. The non-economic evaluation criteria assessed non-price factors of a bid and included five categories of criteria with each having the same weight of 5% (of the 25%). Table 3-4 provides an explanation of and the weighting for the bid evaluation criteria.

TABLE 3-4: ECONOMIC BID EVALUATION CRITERIA

Economic Evaluation Criteria	75% of Total Weight
Evaluate portfolios using levelized cost of energy and levelized cost of capacity	75%

Non-Economic Evaluation Criteria	25% of Total Weight
Transmission Access Plan Feasibility and Arrangements	5%
Development, Construction, Operational and Finance Experience	5%
Real property Acquisition and Environmental Compliance	5%
Externality Benefits and Local Community Support	5%
Best Value Employment Metrics	5%

3.7: 2030 Ready Solicitation

The 2030 Ready RFP Website closed for bid submittal on October 20, 2023 at 4:00 p.m. Mountain Time. Black Hills received 113 bids from 23 unique bidders in response to the RFP.

At bid close, it appeared one bidder had not completed the bid submittal process. Black Hills requested that the IE review the bidder's submittal to confirm that all information was submitted and bid forms downloaded by the bid deadline. The IE confirmed that all information had been submitted by the bid deadline. Based on this information, and in consultation with the IE, Black Hills accepted this bid.

3.8: 2030 Ready Bids

The Company received 114 bids in response to the 2030 Ready RFP. Due to the failure to make payment of the bid fee, one bidder was removed before the initial evaluation of bids began. 113 bids therefore underwent an initial screening process. These bids included an array of resources at varying sizes, technology types, and locations. The 113 bids are inclusive of alternative bids. The 113 evaluated bids represent a total of approximately 15,800 MW, over 90 percent of which were for solar (PV) or solar (PV) with storage projects. Within each group of technology type, there was a wide range of levelized costs between bids. More details regarding levelized cost by technology type can be found in the following sections. Commercial operation dates ranged from May 1, 2026 to January 1, 2030. Most bids included pricing that takes advantage of applicable federal tax credits.

The Company collected a bid evaluation fee for each individual bid submitted. For bids of project sizes up to 10MW, bidders paid a bid evaluation fee of $3,000. For bids greater than 10MW, bidders paid a bid evaluation fee of $10,000. In total, the Company received $630,000 in bid fees. As indicated in the 2030 RFP, the bid evaluation fees collected by the Company will offset the expenses incurred in evaluating the bids.

The bids the Company evaluated are summarized by technology type in Table 3-5 below. The table identifies the total nameplate capacity for each technology type. A list of the bids received, including bid numbers, project name, technology type, nameplate capacity, storage if applicable, storage nameplate capacity, storage duration, estimated annual production, proposed commercial operation date, contract type, pricing, contract term, and Section 123 status, is contained in Highly Confidential Appendix A.

TABLE 3-5: 2030 READY BIDS EVALUATED BY TECHNOLOGY TYPE

Technology	Number of Bids Evaluated	Total Nameplate Capacity
Solar (PV)	57	6,968 MW
Solar (PV) with Energy Storage	38	7,059 MW
Wind	[redacted]	[redacted]
Energy Storage (standalone)	[redacted]	[redacted]
Total	113	15,759 MW

3.8.1: Solar (PV) Bids

Black Hills evaluated 57 bids for standalone solar (PV) resources in response to the 2030 Ready RFP. Contracting options included fixed-price and escalating PPAs, varying contract durations (i.e., 15, 18 or 20 year), build-transfer options, and varying commercial operation dates. Of the 57 standalone solar (PV) bids, 32 were PPAs, 22 were build transfer offers, and 3 were a combination of a PPA plus the option to purchase the project outright. During the evaluation process, the Company removed six PPA bids and their build transfer alternatives from consideration due to lack of bidder responsiveness. All twelve options that were removed from contention originated from a single bidder. Median pricing for the remaining 26 standalone solar (PV) PPA bids was $38.35/MWh. Median pricing for the remaining 19 standalone solar (PV) BTA bids was $1,682/kW. The nameplate capacity ranged from 50 MW to 218 MW and the proposed commercial operation dates ranged from May 2026 to January 2030.

3.8.2: Solar (PV) with Storage Bids

Black Hills evaluated 38 bids for solar (PV) with energy storage resources in response to the 2030 Ready RFP. Alternative pricing options included fixed-price and escalating PPAs, varying contract duration (i.e., 15, 18, or 20 year), build-transfer options, varying storage capacity and hour output, and varying commercial operation dates. 23 of the options were PPAs, 14 were build transfer offers, and one bid proposed a PPA with a BTA option. Median pricing for the PPA bids was $34.95/MWh and 11.59/kW-month. Median pricing for the BTA bids was $2,035/kW. The solar nameplate capacity ranged from 3 MW to 250 MW. Storage nameplate capacity ranged from 2.5 MW to 100 MW, and the storage duration ranged from 2 to 4 hours. The proposed commercial operation dates ranged from May 2026 to January 2030.

3.8.3: Wind Bids

The Company received [redacted] bids for wind resources in response to the 2030 Ready RFP. The nameplate capacity of the wind bids ranged from 100 to 200 MW. The proposed commercial operation dates were between December 2026 and January 2028. All proposed wind bids were PPAs with a fixed-price offer. The median pricing for the bids was [redacted]

3.8.4: Storage (Standalone) Bid

The Company received [redacted] bids for standalone energy storage resources in response to the 2030 Ready RFP. Five bids were PPAs, three were build transfer options, and one bid proposed a PPA agreement with an alternative to purchase the project outright. All [redacted] of the bids proposed a nameplate storage capacity of 50 MW. The storage duration of the bids ranged between 2 and 4 hours. Median pricing for the PPA bids was [redacted]. Median pricing for the BTA bids was [redacted].

3.8.5: Other Bids

The Company did not receive any “other” bids.

3.8.6: Section 123 Resource Bids

The Company received 14 bids claiming Section 123 status. Five bidders who proposed a resource they believe meets the definition of a Section 123 Resource were required to indicate in their proposal why the bidder believes the resource qualifies as a Section 123 Resource. Commission Rule 3602(q) defines “Section 123 Resources” as follows:

“Section 123 Resources” means new energy technology or demonstration projects, including new clean energy or energy-efficient technologies under § 40-2-123(1)(a), C.R.S. and § 40-2-123(1)(c), C.R.S. and Integrated

Gasification Combined Cycle projects under § 40-2-123(2). The Commission further clarified in paragraph 92 of Decision No. C13-0094 in Docket No. 11A-0869E (Public Service Company of Colorado's 2011 ERP) that, per the statutory language, a Section 123 resource must be both new and clean and stated that a clean project must demonstrate that it would likely cause a decrease in greenhouse gas emissions (e.g., carbon dioxide) or significantly reduce other pollutants. A clean project may also result in reduced water usage.

Black Hills worked with these bidders to determine if their projects qualify as a Section 123 Resource, including whether they are "new" and "clean" technologies.

Table 3-6 below shows the number of bids that claimed Section 123 status, broken down by technology type.

TABLE 3-6: SECTION 123 BIDS BY TECHNOLOGY TYPE

Technology	Number of Bids	Total Nameplate Capacity (MW)
Solar (PV)	8	1,138
Solar (PV) + Storage	4	1,098[6]
Storage	2	100

The Company has concluded that none of the 23 bids claiming Section 123 Resource status qualify as a Section 123 Resource. Specifically, none of the 23 bids are "new" and "clean" technologies that meet the Commission definition of a Section 123 Resource. Though the 23 bids do not qualify as a Section 123 Resource, the bids have been evaluated based on their economic value, not based on a designation as a Section 123 Resource. In other words, these projects were able to compete based upon economics and were included in bid portfolios as a result of their competitiveness.

3.8.7 Initially Eliminated Bids

Black Hills determined during the initial screening process that twelve bids (one bidder with six bids, each with an alternate) would not be further evaluated. Additional information was requested from the bidder following the filing of the 30-Day Report. The bidder was unresponsive to multiple attempts to obtain additional information needed to determine if these bids would advance to computer-based modeling. After missing their response deadline by over one week, the IE advised they would be removed from the RFP process if they did not respond. Failure to respond resulted in their removal from the process on December 15, 2023 (11 days after the initial deadline).

[6] Summation of resource and storage capacity.

3.9: 30-Day Report

Pursuant to Commission Rule 3618(b)(I), on November 20, 2023, Black Hills submitted its 30-Day Report to the Commission in Proceeding 22A-0230E. The 30-Day Report provided an overview of the bids received in response to the 2030 Ready Plan RFP. The 30-Day Report included a list of all bids and their alternatives as well as details which included the identity of the bidders that submitted bids, pricing information, technology type, nameplate capacity of proposed project, estimated annual production, storage duration, proposed commercial operation date, and if the bids claimed Section 123 status.

At the time the 30-Day Report was submitted, Black Hills had completed its initial eligibility screening of the bids received in response to the RFP and had begun more in-depth evaluation and due diligence activities.

3.10: Third-party Transmission Opportunities:

In the Phase I Settlement Agreement, the Company committed to explore the cost and potential participation in Public Service Company of Colorado's ("PSCo") Power Pathway Project ("CPP").

As it relates to the CPP, the Settlement Agreement contained the following:

> 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. 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.

As required, the Company engaged PSCo in discussion regarding the ability to potentially participate in the CPP. The Company met with representatives from PSCo and discussed the availability of joint partnership or ownership and the availability of firm transmission rights on the CPP. At this time, a partnership is not an option as PSCo declined to consider Black Hills or other parties as potential partial owners noting their resource plans would likely require full capacity of the CPP. Further, PSCo has represented to the Company that firm transmission rights on the CPP are also not available to Black Hills at this time.

While partial ownership may have impacted bid proposals located on the CPP, the Company received numerous bids proposals that did not interconnect to PSCo's CPP and the Company's Preferred Portfolio does not include projects interconnected to PSCo's CPP.

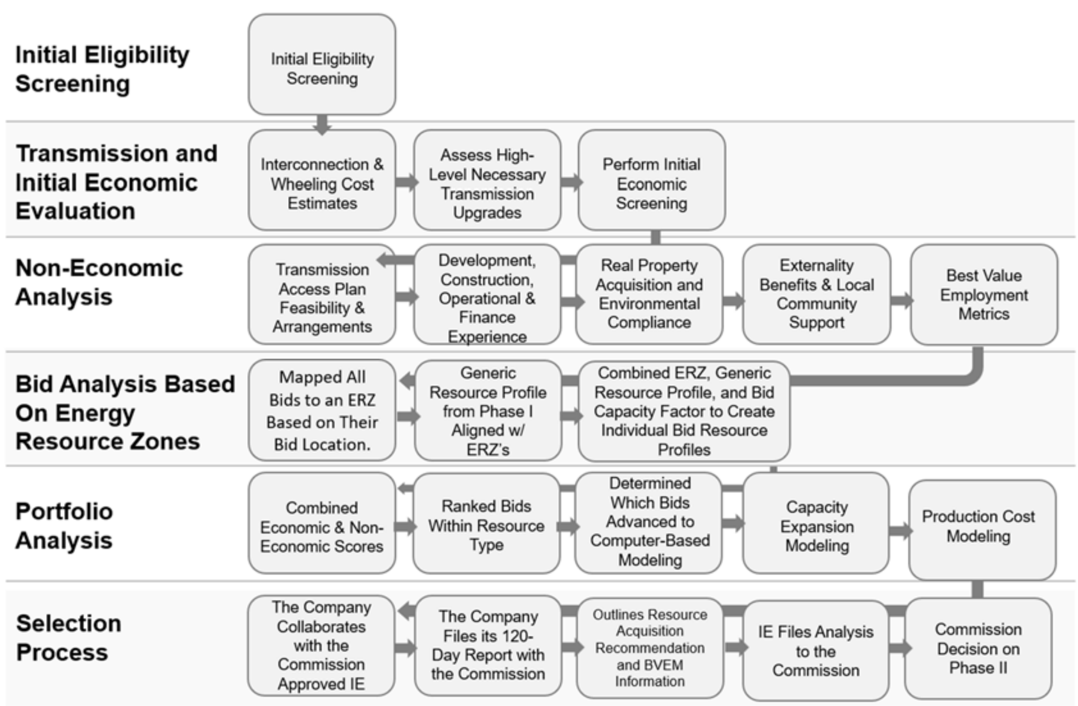
4: 2030 Ready Bid Evaluation

The Black Hills Bid Evaluation Team evaluated the bids not initially eliminated consistent with the Bid Evaluation process set forth in the 2030 Ready RFP. The Bid Evaluation process included both economic and non-economic components, with the weight given to the different factors as described above. The economic evaluation was conducted using bidder supplied data and standard industry modeling methodologies. Non-economic factors were assessed through a due diligence process that gauged the relative risks and benefits of the bid proposal. The Bid Evaluation Team conducted analysis on six portfolios and five sensitivities as defined in the Phase I Decision.

The Bid Evaluation Team is made up of various work groups within the Company, affiliates of the Company, and any consultants hired by the Company to assist with the Bid Evaluation. The Bid Evaluation Team evaluated and selected bids. As part of that process, members of the Bid Evaluation Team communicated with bidders through the IE website during the Bid Evaluation stage. Because an affiliate of Black Hills, Black Hills Electric Generation, LLC, submitted a bid, the Bid Evaluation Team members were identified and a written separation and confidentiality policy was instituted, and communications between the Bid Evaluation Team and the Black Hills Electric Generation, LLC bidding team members were conducted only in the same manner that other bidders communicated with the Company in connection with the RFP.

There were six steps in the Bid Evaluation process: (1) initial eligibility screening; (2) transmission assessment and initial economic evaluation; (3) non-economic analysis; (4) bid analysis based on energy resource zones; (5) portfolio analysis of bids; and (6) selection process. The steps of the Bid Evaluation process are set forth in more detail below and as reflected in Figure 11 below.

FIGURE 4-1: BID EVALUATION PROCESS



4.1: Step 1 – Initial Eligibility Screening

During this step, the Company reviewed and evaluated the information provided for each bid for completeness, consistency with and responsiveness to the proposal content requirements, which were outlined in Section 4 of the RFP. This stage also identified any "fatal flaws" associated with a bid, such as run time restrictions or an unacceptably high level of risk due to the size, age or condition of an existing facility, or the level of development or technology risk of a new facility, such as permitting issues or transmission constraints.

After conducting the screening review, the Company provided bidders with confirmation of submitted bid details and the results of the Company's Initial Eligibility Screening, including the identification of missing and incomplete information. Each bidder was given 5 business days to review the summary and submit additional/clarifying information to enable the Company to evaluate the bid. All bid updates were due by 5:00 p.m. Mountain Time, November 9, 2023. Missing and incomplete information was identified for both applicable bid forms and narrative topics. During the diligence process one bidder became unresponsive and was removed from consideration.

4.2: Step 2 –Transmission Assessments and Initial Economic Evaluation

The Company contacted each bidder that had one or more bids that satisfied the eligibility screening that occurred in Step 1. Step 2 consisted of (1) estimating necessary interconnection costs, (2) assessing high level network transmission upgrades, and (3) performing the initial economic screening. While not entirely concurrent, the activities involved in these three components of Step 2 overlapped to some extent.

Based on the Point of Interconnection provided by each bidder, the Company determined what upgrades, if any, would be necessary for interconnection. Wheeling costs were estimated for off-system bids based on rate information posted on the relevant OASIS page. The Company posted on the 2030 Ready RFP Website a Transmission Interconnection and Network Upgrade Cost Estimate Assumptions document that detailed the significant assumptions used by the Transmission Function to complete interconnection cost estimates and transmission upgrade assessments. The cost estimate assumptions document provided to bidders was used to determine the interconnection costs associated with each bid.

When assessing the impact of bids on the transmission system to identify required network upgrades, Large Generation Interconnection ("LGI") projects in the Company FERC Open Access Transmission Tariff ("OATT") queue were not modeled, unless they are in-service, under construction, have a corresponding transmission service request, or have an executed power purchase agreement. This approach ensures that the transmission system impacts caused by each bid are related directly to that project and not impacted by changes in energy dispatch and/or transmission upgrades driven by non-bid resources that are in the Company LGI queue. Winning bid(s) will be asked to enter LGI requests, if they have not already done so, once this RFP process has concluded and the FERC OATT process will be followed. The Company's FERC-jurisdictional LGI process is currently being revised to meet compliance with FERC Order 2023-A. The Company intends to file OATT redlines no later than the FERC required filing date and will proceed with the transitional process as outlined in the Order.

The Company will encourage the recommended bid(s) to submit an interconnection request and obtain a queue position prior to the Order 2023 timelines in order to be included in the Transitional Cluster Study. As part of the Transitional Cluster Study process, the Company will perform a steady state and transient stability analysis of all interconnection requests participating in the Transitional Cluster study, which is expected to include the preferred portfolio bids.

Per the RFP, "[b]idders will be responsible for procuring transmission service and all transmission and scheduling costs needed to deliver power from the proposed resource to the identified point of delivery on the Company's transmission system. Proposals that rely upon supply resources located outside of the Company's system must provide for the delivery of the full capacity amount to the Company's transmission system. The Company is not currently a network customer of any other transmission provider and, therefore, if transmission is required on any other transmission provider's system, the bidder must obtain Firm Point-to-Point Transmission Service." It is the Company's expectation that bidders verified that firm point-to-point transmission service is available on third-party transmission service provider's systems or had coordinated with those third-parties on future transmission service availability.

4.2.1: Transmission Assessment

The bids that identified a Point of Interconnection on the Company's transmission system were evaluated by the Company's Transmission Function for an estimate of interconnection and network upgrade costs required to deliver the entire proposed capacity and energy from the proposed facility Point of Interconnection with the Company's system to the Company's customers. Bids that were proposed to interconnect to a third-party transmission system were reviewed to verify the assumed third-party transmission rate.

Of the 49 bids that were passed through to the computer-based modeling, seven of those bids were submitted with a proposed third-party interconnection point. Three of those seven bids proposed to interconnect to the Tri-State Generation & Transmission Association transmission system. The other four bids proposed to interconnect to a planned transmission substation owned by Public Service Company of Colorado. The remaining 42 bids were submitted with a proposed Point of Interconnection to the Black Hills system at a Company-owned substation (including substations jointly owned by the Company with other transmission owners). The bids that proposed to interconnect to facilities external to the Black Hills system were required to include the cost of firm transmission service to deliver energy to the Black Hills transmission system. For these bids, the Company identified the appropriate firm transmission service rate and made adjustments to estimate the future transmission rate, taking into consideration Commission-approved transmission projects and historical transmission system use growth rates. These estimated third-party transmission service costs were incorporated into the bid evaluation as well as the computer-based modeling.

The impact of these analyses on a bidder's project was a factor in the Bid Evaluation. Network upgrade cost estimates as well as the degree of difficulty of completing the interconnection were contributing factors to the overall ranking of the bids. For bids connecting at substations jointly owned by another transmission owner, interconnection would need to be coordinated, including additional studies performed by the other transmission owner, as well as additional land acquisition and substation expansion needs. These considerations were part of the ranking of the bids.

4.2.2: Initial Economic Evaluation

The Bid Evaluation Team screened proposals that advanced beyond Step 1 (Initial Eligibility Screening) based on individual bid economics and associated transmission costs. Levelized costs were calculated for each bid and were used to compare each bid's economic value in relationship to the other bids of the same technology.

To calculate the levelized costs for each bid, the Company first determined the net present value of the estimated annual costs of the bid. Black Hills then calculated a level annual payment over the same period, which would result in the same net present value. This process was repeated to calculate levelized annual energy costs, levelized annual capacity costs, and levelized annual transmission costs for each bid. These levelized annual costs were summed with estimated resource integration costs to yield the total levelized annual resource cost.

For PPA bids, Black Hills calculated the annual estimated cost based on the price offered and the bidder-supplied estimated annual production and storage capacity. For build transfer offers, the Company calculated the annual estimated costs based on debt service, depreciation, return on equity, income tax, any applicable production/investment tax credits, and bidder supplied operations and maintenance costs. For bids directly connected to the Company's transmission system, the Company calculated the annual estimated transmission costs based on estimated network upgrade costs, debt service, depreciation, return on equity, and income tax. For bids connected to a third-party transmission system, the Company calculated the annual estimated transmission costs based on publicly available cost information including current transmission rates and planned investments. All RECs generated will be transfer to and retired by the Company at no additional cost, therefore no REC value benefits were credited to the levelized cost calculations for any renewable generation projects.

For solar and wind bids, the total levelized annual resource cost was divided by the annual generation to produce an LCOE in $/MWh. For storage bids, the total levelized annual resource cost was divided by the storage capacity to provide an LCOC in $/kW-month.

For solar plus storage bids, both an LCOE and an LCOC were calculated. To overcome the challenge of comparing bids on multiple metrics, the levelized cost of capacity was equalized across bids and a new levelized cost of energy was calculated to capture the difference between the total levelized annual resource cost and the equalized levelized cost of capacity. The Company calculated the storage price per hour duration for each PPA bid with a storage component. For example, a 50 MW 4-hr with a $12.00/kW-month PPA price would have a price per hour duration of $3.00/kW-month ($12.00/kW-month/4-hr). The individual bid prices were then averaged to obtain the average storage price per hour duration. This average was then multiplied by each solar plus storage bid's nameplate capacity in kW, duration in hours, and 12 months to produce an equalized annual capacity cost. The levelized energy cost was then calculated by subtracting the equalized annual capacity cost from the total levelized annual resource cost and dividing by the annual generation. Once these calculations were complete, the solar plus storage bids could be compared based upon the levelized energy cost alone because the levelized cost of capacity was the same for bids with equal durations. Note these steps were taken to rank bids for the purposes of determining which bids would be advanced to computer-based modeling. Once bids were advanced to computer-based modeling, bidder information was directly used in the portfolio analysis of bids described in more detail in Section 4.5 below.

Finally, the Company assigned economic criteria points to each bid based on its levelized cost in relation to other bids within the same resource type category (solar, solar plus storage, wind). The minimum and maximum levelized cost of energy were determined for the solar and solar plus storage bids while the minimum and maximum levelized cost of capacity was determined for stand-alone storage bids. Within each resource type category, the bid with the lowest levelized cost was awarded 75 points and the bid with the highest levelized cost was awarded 0 points.

4.2.2.1: Wind and Solar Integration Cost Adders

As noted above, the Company added estimated resource integration costs to the price offered for each eligible energy resource bid. Black Hills' service territory in Colorado is in the PSCo balancing authority area, and, accordingly, Black Hills is subject to PSCo's Open Access Transmission Tariff ("OATT"), specifically Schedule 3 – Regulation and Frequency Response Service, and Schedule 16 – Flex Reserves. Per the PSCo OATT, Schedule 3 is applicable to all variable energy resources, while Schedule 16 is only applicable to wind resources. Currently, there is no PSCo Flex Reserve solar tariff equivalent to the Schedule 16 tariff for wind. Therefore, Schedule 3 costs were applied to all wind and solar bids received, while Schedule 16 costs were only be applied to wind bids. Absent an applicable PSCo OATT schedule or provision, Black Hills will be able to use existing flexible capacity to self-regulate solar at no incremental cost. The PSCo OATT charges are based on installed capacity and not generation. The Company has thus applied the charges on a $/kW-month basis to be consistent with the PSCo OATT.

Charges under Schedules 3 and 16 are determined based on three inputs: resource capacity (kW), Reserve Obligation percentages, and Ancillary Service Delivery rates ($/kW month). For each kW of applicable new resources, the monthly Schedule 3 and 16 charges are the product of the Resource Obligation percent and the Ancillary Service Delivery rates. The Schedule 3 Reserve Obligation is 2.03 percent, and the Schedule 16 Reserve Obligation is 16.15 percent. The 2023 Schedule 3 Ancillary Service Delivery rate in the PSCo OATT is $7.9490/kW-month. The current Schedule 16 Ancillary Service Delivery rate in the PSCo OATT is $6.4980/kW-month.

Table 4-2 below contains the wind and solar integration costs that were used for the initial economic screening, based on the 2023 PSCo OATT rates.

TABLE 4-2: INTEGRATION COSTS

	Schedule 3 ($/kW-month)	Schedule 16 ($/kW-month)	Total ($/kW-month)
Wind	0.1614	1.0494	1.2108
Solar	0.1614	0.0000	0.1614

4.3: Step 3 – Non-Economic Analysis

This analysis assessed the non-price characteristics of each of the bids and assigned a maximum of 25% of the total bid score to each bid (each of the criteria was worth a maximum of 5%). Non-price factors included the following:

- Transmission Access Plan Feasibility and Arrangements
- Development, Construction, Operational and Finance Experience
- Real property Acquisition and Environmental Compliance
- Externality Benefits and Local Community Support
- Best Value Employment Metrics

Appropriate members of the Bid Evaluation Team reviewed the information submitted with each bid and determined the bid's score for each of the factors identified above. Black Hills created a scorecard to quantify the impacts of these non-economic factors. The non-economic scorecard results for each of the bids that were advanced to computer-based modeling are posted in Appendix F.

4.4: Step 4 – Bid Analysis based on Energy Resource Zones

Bids were assigned to a specific energy resource zone ("ERZ") based upon the definitions as provided in Section 5.2 of the RFP. Please see the Assumptions Section 3.5 and Appendix H, E3 Technical Report for additional information.

4.5: Step 5 – Portfolio Analysis of Bids

After conducting the non-economic analysis, the Company combined the economic and non-economic scores and ranked bids within each resource type category to determine which bids to advance to computer-based modeling. Bids were rejected at this stage for one or more of the following reasons:

1. The levelized annual resource cost was higher than other bids.
2. Less competitive options for single projects were eliminated to increase bidder diversity.
3. Less competitive bids within a technology were eliminated to allow for diversity in project sizes and geographic location.
4. Low score in one or more non-economic characteristics.

The combined economic and non-economic scorecard for each bid is provided as Appendix A. Consistent with the Settlement Agreement, if a bid was advanced to computer-based modeling all offered pricing variations of that bid were advanced to computer-based modeling. Table 4-3 below details the number of bids that were advanced for each resource type and the range of levelized annual resource cost of the bids that were advanced. Note: the cost ranges below reflect the bid price, transmission costs, and integration costs as described above. The solar with energy storage range also reflects equalization of the capacity costs as described above.

Table 4-3: 2030 Ready RFP Bids by Technology Type

Technology	Number of Bids Advanced	Levelized Annual Resource Cost Range ($/MWh, $/kW-month)
Solar (PV)	29	$34 - $72
Solar (PV) with Energy Storage	12	$28 - $42
Wind	[redacted]	
Energy Storage (standalone)		

4.5.1: Notification of Advancement to Computer-Based Modeling

On December 19, 2023, bidders were notified through the 2030 Ready RFP Website whether their bid had advanced to computer-based modeling. The Company supplied a Bid Advancement Notification to each bidder for bid(s) that would be advanced to computer-based modeling. The Company supplied a Bid Rejection Notification to each bidder for bid(s) that would not be advanced to computer-based modeling. Examples of the documents sent to bidders is included in Appendix D. These notifications prompted very few bidder questions related to the RFP evaluation review schedule or on the confirmation of bid details. Black Hills answered all questions through the 2030 Ready RFP website.

4.5.2: Computer-based Modeling and Portfolio Analysis

The Company used portfolio analysis to evaluate the relative cost of Black Hills' resource portfolio, with a selected portfolio of bids, on a PVRR basis. The general planning assumptions used in the modeling process are set forth in Section 3.5 above.

The Company's 2022 ERP was the result of a proceeding in Proceeding No. 22A-0230E in which interested parties were able to review, challenge, and suggest changes to the modeling framework and methodologies used by the Company. The 2022 ERP resulted in a Commission-approved modeling framework. The 2030 Ready RFP is the Phase II component of the 2022 ERP, which was proposed to be implemented through a competitive solicitation to determine whether the Company can greatly increase its renewable generation mix without increasing customer costs.

Consistent with the 2022 ERP proceeding, the Company engaged a consultant, Energy & Environmental Economics ("E3") to complete the capacity expansion and production cost modeling that comprises the Company's computer-based modeling. E3 used its software to produce unique expansion plans for each portfolio. Capacity expansion and production cost modeling are described in greater detail in the following subsections.

4.5.3: Capacity Expansion and Production Cost Modeling

Capacity expansion and production cost modeling was conducted to determine the portfolio of future resources that meets the needs of Black Hills' customers over the Planning Period in the least cost manner, while maintaining system flexibility and complying with environmental laws and regulations. Subsequent to those analyses, the Company conducted portfolio analysis as approved in the Phase I Decision. Utilities must plan for future customer needs for electricity in an environment of significant uncertainty. Thus, the portfolio analysis conducted for this RFP examined uncertainty under a variety of possible future conditions, as reflected in the sensitivities analysis.

Capacity expansion modeling is a process used to determine the appropriate type, size, and timing for economic resource additions. The utility's existing generation resources, bid specific resources, and future generic resource alternatives are input into a capacity expansion model with a forecasted load. The model simulates utility operation and serves the forecasted load with the utility's existing resources and economically selects additional resources from the list of available bids and generic resource alternatives. The typical criterion for evaluation is the expected total costs subject to meeting load plus reserves and various resource planning constraints, such as Colorado's CEP legislation. Appendix E shows the resource portfolios produced as a result of the capacity expansion modeling for each portfolio.

While bids with similar technology, size, storage duration (if applicable), and PPA term are similar, they are not necessarily exact. The algorithms within the capacity expansion model optimize a resource portfolio of bid(s) to minimize PVRRs. Differences of in-service dates, renewable generation profiles, and pricing may allow the capacity expansion model to reach a more optimal (i.e., lower PVRR) solution for a resource portfolio by slightly altering the expansion to plan to include bids that work well together. By utilizing the capacity expansion model to develop bid portfolios, the Company directly used the general planning assumptions and bidder supplied data to analyze how each bid best fits into a portfolio of bids selected in the expansion plan.

Production cost modeling simulates the hourly operation of the resources available to a utility and is used to forecast system cost and risk exposure. A production cost model includes an hourly dispatch model, with a load forecast and fixed resources to serve that load. The model simulates a given load every hour, then economically serves that load with the available resources, and captures the associated cost. Production cost modeling can also be completed using multiple iterations with changing variables. This form of modeling measures sensitivities associated with the modeled plan subject to changing variables.

At the request of the IE, E3 completed modeling of thirteen mock bids before the bids were released to the Company in October 2023. The modeling results for the mock bids were supplied to the IE for review. During the evaluation process, but prior to bid modeling selection, an updated model baseline was created to allow more efficient optimization given the range of commercial operation dates proposed by bidders. At the conclusion of all modeling, the mock bids were re-run in April 2024 against the updated baseline, to confirm that no additional inputs or variables were revised during the bid evaluation process. Review of the modeling results for the mock bids are anticipated to be confirmed that the inputs and variables remained unchanged, relative to the changes outlined in the baseline update. The modeling results for the April 2024 mock bids were supplied to the IE for review.

4.6: Step 6 – Selection Process

The selection process includes several steps, including the filing of this 120-Day Report. The results of the Company's Bid Evaluation were presented above in Section 1, as well as below in Section 5. In these sections, Black Hills identifies and explains its Preferred Portfolio, back-up bids, and alternative portfolios.

The Company will also provide the Commission with the best value employment metrics information provided by these bidders under ERP Rule 3616 and by the Company consistent with ERP Rule 3611. The BVEM for the preferred portfolio, which was provided by the bidders, is included in Highly Confidential Appendix L.

The Company will work with the IE to assist the Commission with the complex issues and analyses involved in utility resource modeling and selection. By May 17, 2024, the IE will separately file a report that contains the IE's analysis of whether the utility conducted a fair bid solicitation and Bid Evaluation process, with any deficiencies specifically reported. The IE will provide confidential versions of these reports to Staff and OCC. Intervenors then have the opportunity to file Responses to this 120-Day Report on June 3, 2024, with Company Rebuttal Responses to be filed on June 17, 2024. Black Hills has indicated that it seeks a final Commission decision no later than August 15, 2024 to ensure sufficient time to finalize negotiations with bidders and ensure awarded bidders can complete projects in time to take advantage of federal tax credits.

If a decision is made that the Company should acquire specified renewable energy resources, the Company and the successful bidder(s) will negotiate with a goal to obtain signed agreements within the timelines established by Commission Rule 3613(i).

4.7: Clean Energy Plan Guidance and Verification Workbooks

The Air Pollution Control Division ("APCD"), within the Colorado Department of Public Health and Environment ("CDPHE"), developed a Clean Energy Plan Guidance ("CEP Guidance") and Verification Workbook documents to govern assessment and verification that a utility's CEP achieves the requirements as defined in both HB 19-1261 and SB 19-236.[7] The CEP Guidance includes a verification workbook in the form of a spreadsheet tool to assist verification that a utility's resource plan will achieve the statutory emission reduction targets. The Company is providing with its 2030 Ready RFP the verification workbook to promote successful verification. The Company's Preferred Plan achieves an 89% reduction in GHG emissions from 2005 levels based on retail sales. Black Hills has completed verification workbooks for all RFP modeling runs in Appendix J.

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[7] Available at https://cdphe.colorado.gov/air-pollution/climate-change#Energy.

4.8: CDPHE Phase I Verification Workbook Review

CDPHE issued their Verification Report of the Company's Phase I portfolios on August 31, 2022, with the following statement:

Based on this Phase I review, APCD verifies that the portfolios submitted by the Black Hills Colorado Electric, LLC have used the workbook to accurately calculate expected emissions reductions. Nineteen (19) of the twenty-three (23) portfolios would be expected to meet the minimum requirements under the statutes to qualify as a CEP and for the Safe Harbor.

CDPHE's review included the Company's 2005 baseline established within the CDPHE Verification Workbooks for each portfolio, as well as projected emission reductions. The Commission directs CDPHE to file its Phase II Verification Report within 30 days of the 120-Day Report.

5: Bid Evaluation Results

The methodology used to evaluate bids received in response to the 2030 Ready RFP allowed Black Hills to conduct analysis as determined in the Phase I Decision. The portfolio and sensitivity analysis provided a meaningful look into determining the best selection of bids to create a portfolio of resources to serve customer needs.

Consistent with the 2022 ERP proceeding, the Company engaged a consultant, Energy & Environmental Economics ("E3") to complete the capacity expansion and production cost modeling that comprises the Company's computer-based modeling. E3 used its software to produce unique expansion plans for each portfolio.

The sections below provide additional detail about the Bid Evaluation results and the Company's preferred portfolio and the Company's proposed back-up bids.

5.1: Portfolio Analysis

Portfolio analysis was conducted during which the Capacity Expansion module was used to derive optimal resource expansion plans. The portfolios include variations in inputs representing the significant sources of portfolio cost variability and risk. In addition, the Production Cost module was used to evaluate granular variations in dispatch and sensitivities. The portfolios that were evaluated are reflective of the Phase I Decision. A brief description of the variables for these scenarios, and their corresponding variations, are listed below:

1. **<u>ERP – No SC-GHG Portfolio</u>**
   - All existing resources included as available resources
   - Base peak demand and annual energy forecasts
   - Base natural gas, hydrogen, and economy energy forecasts
   - Seasonal firm market purchases up to 50 MW
   - Bids as resource options during the resource acquisition period
   - Generic conventional and renewable energy resource options
   - Replacement Chain Method

2. **<u>Base ERP with SC-GHG</u>**
   - Investigated the impact SCC and SCM would have on the ERP – No SC-GHG portfolio
   - Added the SCC and SCM assumptions
   - Assumed all other modeling variables as described in "ERP – No SC-GHG portfolio"
   - Replacement Chain and Annuity Methods

3. **<u>Clean Energy Plan</u>**
   - Investigated the impact Clean Energy Plan requirements would have on the Base ERP with SC-GHG
   - Required 80% CO_2 emissions reduction by 2030 and 100% clean energy by 2050

- Targeted 50% utility ownership
- Assumed all other modeling variables as described in "Base ERP with SC-GHG portfolio"
- Replacement Chain and Annuity Methods

4. **<u>40 Percent Ownership Test</u>**
    - Investigated the impact 40% ownership would have on the Clean Energy Plan portfolio
    - Targeted 40% utility ownership
    - Assumed all other modeling variables as described in "Clean Energy Plan portfolio"
    - Replacement Chain and Annuity Methods

5. **<u>Geographic Diversity</u>**
    - Investigated the impact geographic diversity would have on the Clean Energy Plan portfolio
    - Included only bids that qualified for geographic diversity
    - Assumed all other modeling variables as described in "Clean Energy Plan portfolio"
    - Replacement Chain and Annuity Methods

6. **<u>Local Economic Development</u>**
    - Investigated the impact local economic development would have on the Clean Energy Plan portfolio
    - Included only bids that qualified for local economic development
    - Assumed all other modeling variables as described in "Clean Energy Plan portfolio"
    - Replacement Chain Method

These portfolios allowed for various sensitivities to be analyzed around their individual assumptions. Different portfolios change the assumptions that are likely to influence the size, type, and timing of resource additions and investigate their resultant impact. Modeling the portfolios evaluates the risk exposure to Black Hills because of these future uncertainties. Table 5-1 summarize the assumptions used for each portfolio.

TABLE 5-1: SENSITIVITY PORTFOLIO CHARACTERISTICS SUMMARY

Settlement Portfolio Number	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5	Portfolio 6
Scenario	**ERP No SC-GHG**	**Base ERP with SC-GHG**	**Clean Energy Plan**	**40% Ownership Test**	**Geographic Diversity**	**Local Economic Development**
Load Growth	Median	Median	Median	Median	Median	Median
Electric Price	Median	Median	Median	Median	Median	Median
Gas Price	Median	Median	Median	Median	Median	Median
Hydrogen Price	Median	Median	Median	Median	Median	Median
Social Cost of Carbon Adder	None	Yes	Yes	Yes	Yes	Yes
Methane Cost Adder	None	Yes	Yes	Yes	Yes	Yes
Emissions Targets	None	None	Yes	Yes	Yes	Yes
Ownership	None	None	50%	40%	50%	50%
Geographic Diversity	None	None	None	None	Yes	None
Local Economic Development	None	None	None	None	None	Yes
Annuity/Replacement Chain	Replacement Chain	Both	Both	Both	Both	Replacement Chain
Model	RESOLVE	RESOLVE	RESOLVE	RESOLVE	RESOLVE	RESOLVE

The resource expansion plans for portfolios add varying amounts of wind, solar, storage, and SFMP during the resource acquisition period ("RAP"). The capacity expansion model was restricted from selecting SFMP in Portfolio 3 – Clean Energy Plan to ensure sufficient physical resources were acquired to meet the capacity requirements and that no additional fossil-fueled resources were included in the CEP. Capacity Expansion modeling results (incremental resource portfolios) for these scenarios are shown in Table 5-2.[8] Please see Appendix E for the detailed expansion plans throughout the planning period.

[8] Expansion plan portfolios are representative of the Company's preferred replacement chain methodology.

TABLE 5-2: OPTIMAL EXPANSION PLANS – SCENARIO ANALYSIS INCREMENTAL ADDITIONS (MW)

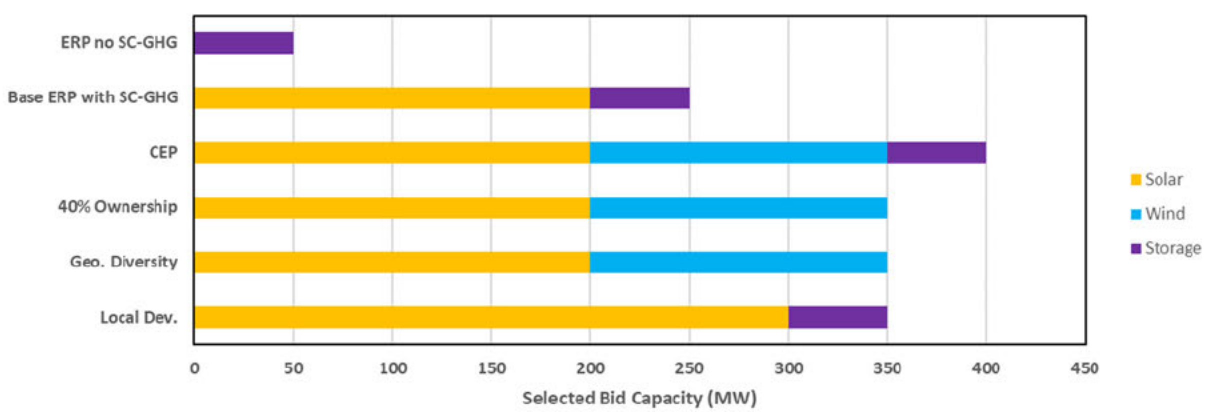
Portfolio		2026	2027	2028	2029	2030
ERP – No SC-GHG	Wind	0	0	0	0	0
	Solar	0	0	0	0	0
	Storage	0	50	0	0	0
	Gas	0	0	0	0	0
	SFMP	0	0	30	40	40
Base ERP with SC-GHG	Wind	0	0	0	0	0
	Solar	0	200	0	0	0
	Storage	0	50	0	0	0
	Gas	0	0	0	0	0
	SFMP	0	0	0	0	0
CEP	Wind	0	150	0	0	0
	Solar	0	200	0	0	0
	Storage	0	50	0	0	0
	Gas	0	0	0	0	0
	SFMP	0	0	0	0	0
40% Ownership	Wind	0	150	0	0	0
	Solar	0	200	0	0	0
	Storage	0	0	0	0	0
	Gas	0	0	0	0	0
	SFMP	0	0	0	10	20
Geographic Diversity	Wind	0	150	0	0	0
	Solar	0	200	0	0	0
	Storage	0	0	0	0	0
	Gas	0	0	0	0	0

Portfolio		2026	2027	2028	2029	2030
	SFMP	0	0	0	10	20
Local Economic Development	Wind	0	0	0	0	0
	Solar	100	200	0	0	0
	Storage	0	50	0	0	0
	Gas	0	0	0	0	0
	SFMP	0	0	0	0	0

5.2: Preferred Portfolio Analysis

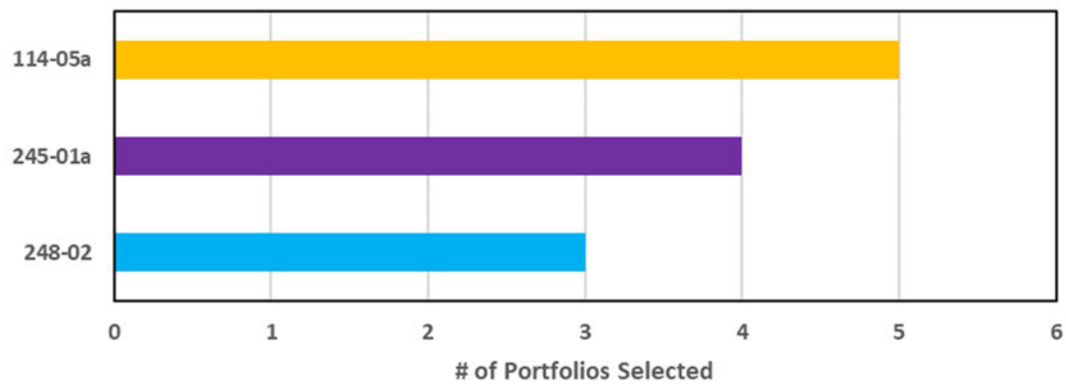
The resource portfolios add varying amounts of wind, solar, and storage during the RAP. Capacity Expansion modeling results for each portfolio are summarized in Figure 5-1.

FIGURE 5-1: TOTAL BID CAPACITY SELECTED BY RESOURCE TYPE ACROSS ALL SCENARIOS



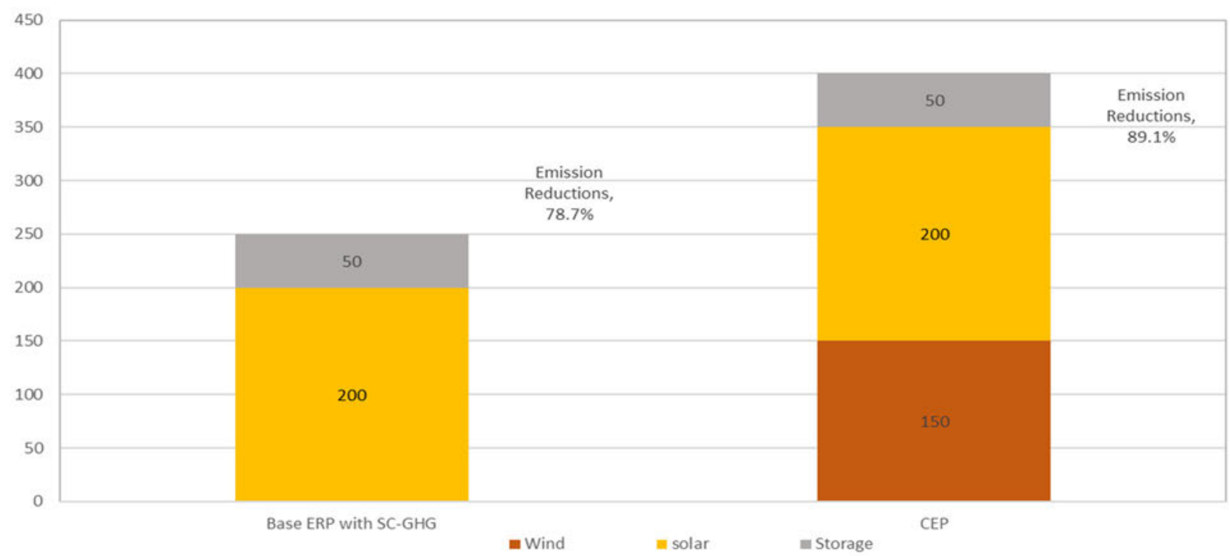
In many of these portfolios, the portfolio makeup includes some combination of 200 MW of solar, 150 MW of wind, and 50 MW of storage. This demonstrates these are the right size resources for the system. Across these portfolios 3 bids were primarily selected: Bid 114-05a, a 200 MW solar bid; bid 248-02, a 150 MW wind bid; and bid 245-01a, a 50 MW storage bid. Figure 5-2 provides the number of times each of these bids were selected out of 6 portfolios. Each bid results in being selected in at least 3 out of 6 portfolios.

FIGURE 5-2: NUMBER OF PORTFOLIOS IN WHICH BIDS ARE SELECTED



The resource portfolios for Base ERP with SC-GHG (Portfolio 2) and CEP (Portfolio 3) are provided in Figure 5-3. Both portfolios are comprised of a combination of 200 MW solar and 50 MW of storage, and the CEP selects an additional 150 MW of wind. The same bids are selected for each technology type in both portfolios.

FIGURE 5-3: OPTIMAL EXPANSION PLANS – CEP AND ERP SCENARIO ANALYSIS RESOURCE ADDITIONS BY 2030 (MW)



Present Value Revenue Requirements ("PVRR") were calculated for each of the portfolios using the portfolio assumptions as described above. The PVRRs for the portfolio analysis are shown in Figure 5-4 and Figure 5-5, reported in 2021 dollars.

FIGURE 5-4: PORTFOLIOS – DETERMINISTIC PVRRS (2026-2050) -25 YEAR PVRR ($MM)

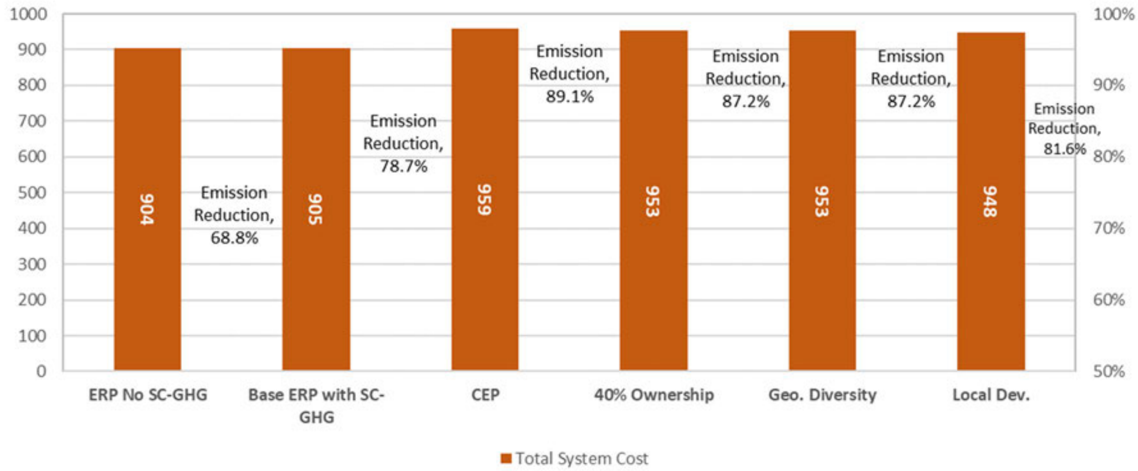
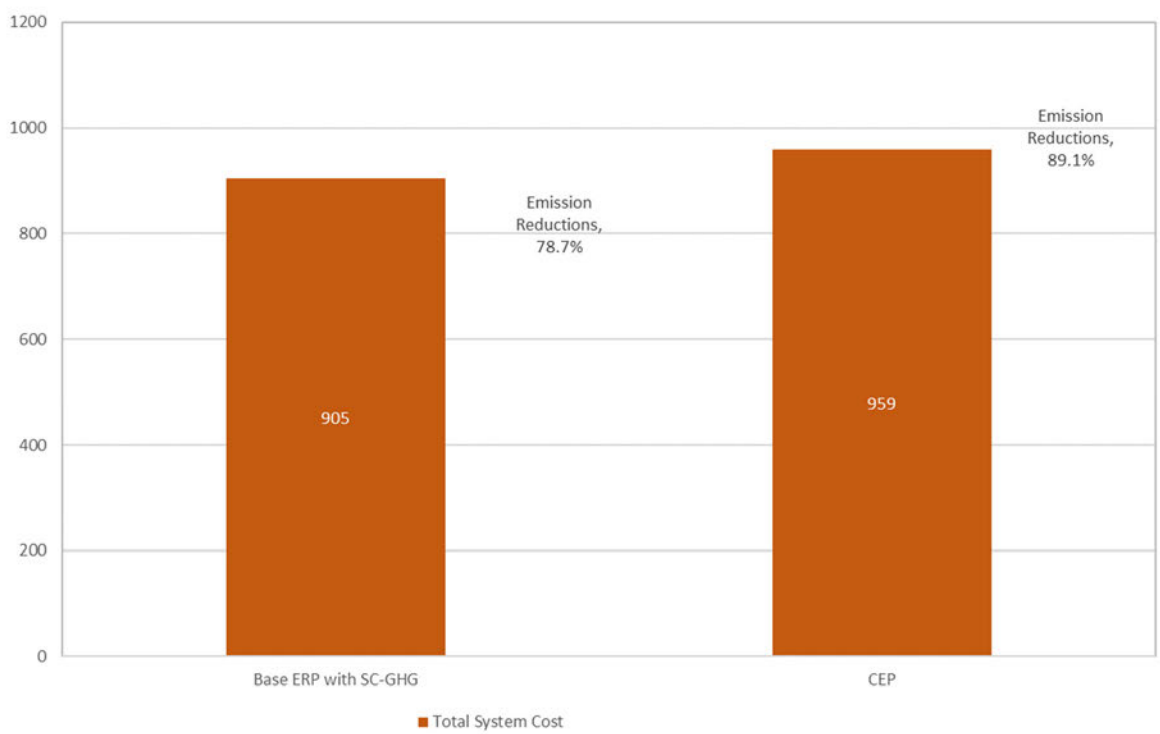


FIGURE 5-5: KEY PORTFOLIOS – DETERMINISTIC PVRRS (2026-2050) 25 YEAR PVRR ($MM)



The least-cost portfolio based on the PVRR analysis is Portfolio 1- ERP No SC-GHG, however it only achieves 68.8 percent greenhouse gas emission reduction by 2030. The next least-cost portfolio based on the PVRR analysis is the Portfolio 2- Base ERP with SC-GHG, however it only achieves a 78.7 percent greenhouse gas emission reduction by 2030. The CEP Portfolio achieves 89.1 percent greenhouse gas emission reduction by 2030. During the RAP, the CEP and Base ERP with SC-GHG have similar resource acquisitions. The modeling completed for the Base ERP with SC-GHG portfolio did not include the requirement to meet the 80% reduction, and therefore the total system cost in the graph above reflects the cost of a different portfolio mix than the CEP portfolio.

The renewable energy curtailments resulting from the Preferred Portfolio are relatively small compared to the overall system load. Only six percent of the generation was curtailed in 2030, or 174 GWh. As a comparison, the total system energy forecasted for 2030 is 2,115 GWh. Similarly, the Base ERP with SC-GHG and Local Economic Development portfolios curtailed one and four percent of the 2030 generation, respectively. Table 5-3 provides the curtailments for each of the portfolios. This demonstrates the agility of the system's resources to effectively manage renewables while achieving state policy emissions goals.

TABLE 5-3: 2030 PORTFOLIO CURTAILMENTS

Portfolio	Curtailments (GWh)	Percent of Generation Curtailed
ERP – No SC-GHG Portfolio	0	0%
Base ERP with SC-GHG	33	1%
Clean Energy Plan	158	5%
40 Percent Ownership Test	244	8%
Geographic Diversity	244	8%
Local Economic Development	133	4%
Preferred Plan	174	6%

5.3: 2030 Ready Preferred Portfolio

As a result of the load and resource balance[9], capacity expansion, production cost modeling, and retail rate impact evaluations, Black Hills is recommending the Clean Energy Plan (with social costs) scenario as the support for the Preferred Plan as it cost effectively achieves Colorado's state policy objectives. The Preferred Plan's PVRR is shown in Table 5-4. The Preferred Plan is estimated to achieve 89 percent emissions reductions by 2030. This Plan allows the Company to meet the CEP requirements and policy objectives. The Company has prepared Air Pollution Control Division Verification Workbooks in accordance with their guidelines, as shown in Appendix J.

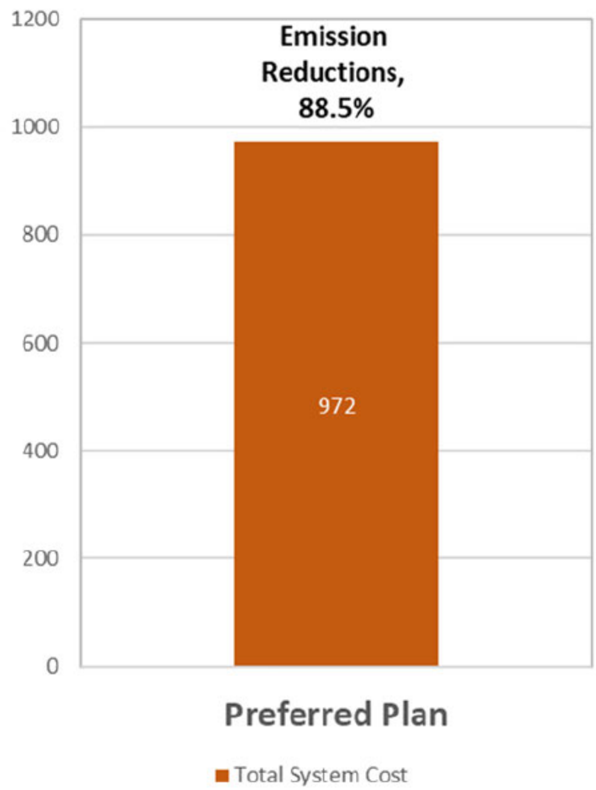
[9] The Company's load and resource balance for existing resources and the Preferred Plan are presented in Appendix I.

TABLE 5-4: PREFERRED PLAN LOAD AND RESOURCE BALANCE (2026-2030)

	2026	2027	2028	2029	2030
Peak Demand	467	468	469	470	471
DSM	19.1	19.1	19.1	19.1	19.1
Net Peak Demand	**447**	**449**	**450**	**451**	**452**
Existing Resources *					
Pueblo Diesels					
Airport Diesels	10	10	10	10	10
Rocky Ford Diesels	10	10	10		
PAGS LMS100 1	90	90	90	90	90
PAGS LMS100 2	90	90	90	90	90
Busch Ranch I Ownership**	2.0	2.0	2.0	2.0	2.0
Peak View Ownership**	8.3	8.3	8.3	8.3	8.3
PAGS LM6000	40	40	40	40	40
Total Resources	**250**	**250**	**250**	**240**	**240**
Contract Purchases*					
PAGS CC PPA	200	200	200	200	200
Busch Ranch I PPA**	2.0	2.0	2.0	2.0	2.0
Busch Ranch II PPA**	8.1	8.1	8.1	8.1	8.1
Total Purchases	**210**	**210**	**210**	**210**	**210**
Proposed Resources & Purchases***					
150 MW Wind PPA (bid 248-02)-12/1/2027			35	35	35
200 MW Solar (bid 114-05a)-12/31/2026		55	55	54	54
50 MW Storage (bid 248-19)-12/1/2027			42	42	42
Total Proposed	**0**	**55**	**132**	**131**	**131**
Total Resources and Purchases	**460**	**515**	**592**	**582**	**582**
20% Reserve Margin (MW)	89	90	90	90	90
Total Capacity Requirement (peak plus reserves)	**536.4**	**538.8**	**540.0**	**541.2**	**542.4**

	2026	2027	2028	2029	2030
Total Resources minus Total Capacity Requirement					
In MW[10]	**(76.1)**	**(23.5)**	**52.1**	**40.6**	**39.1**
As a percentage	**(14.2%)**	**(4.4%)**	**9.6%**	**7.5%**	**7.2%**
Notes:					
* Summer rated capacities shown.					
** 13.57% of all existing wind resources count as accredited capacity.					
*** 23.33% of proposed wind PPA count as accredited capacity.					
*** 27.5% of proposed solar resources count as accredited capacity.					
*** Solar degrades at .5% annually.					
*** 84% of proposed storage resources count as accredited capacity.					

FIGURE 5-6: PREFERRED PORTFOLIO – DETERMINISTIC PVRRS (2026-2050) 25 YEAR PVRR ($MM)



[10] In 2026 there were no competitive bids to solve this capacity need; however, the Company can address this capacity need with seasonal firm market purchases. The planning reserve margin is satisfied when the bids fully come on-line by the end of 2027. Please see the E3 Technical Report, Appendix H, for additional planning reserve model assumptions.

The Company is not recommending the other portfolios for a variety of reasons. The ERP No SC-GHG and Base ERP with SC-GHG (Portfolios 1 and 2) do not achieve the 80% greenhouse gas emissions reduction. The 40% Ownership and Geographic Diversity (Portfolios 4 and 5) rely on seasonal firm market purchases and are only slightly lower PVRR. The Local Economic Development (Portfolio 6) achieves the 80% emissions reduction target at a relatively low direct cost to customers and is a viable alternative to the Preferred Portfolio. The Preferred Portfolio provides an avenue for meeting Colorado's state policy objectives at a reasonable cost, ensures sufficient physical resources are acquired to meet the capacity requirements, and results in no additional fossil-fueled resources acquired in this RFP.

5.4: Sensitivity Analysis

Portfolio analysis using the Capacity Expansion module was conducted to derive optimal resource expansion plans. The Preferred Plan's portfolio of resources was further analyzed by conducting sensitivity analysis. The sensitivities addressed, as per the Phase I Decision, are as follows:

1. **Participation within a Regional Market (Settlement Portfolio 7)**
   - Investigated the impact SCC and SCM would have on the Preferred portfolio
   - Added the SCC and SCM assumptions
   - Assumed all other modeling variables as described in "Preferred portfolio"
   - Replacement Chain Method

2. **High Gas**
   - Investigated the impact high gas prices would have on the Preferred portfolio
   - High natural gas and economy energy forecasts[11]
   - Resource portfolio used the Preferred Plan resources
   - Assumed all other modeling variables as described in "Preferred portfolio"

3. **Low Gas**
   - Investigated the impact low gas prices would have on the Preferred portfolio
   - Low natural gas and economy energy forecasts[12]
   - Resource portfolio used the Preferred Plan resources
   - Assumed all other modeling variables as described in "Preferred portfolio"

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[11] Confidential Appendix G contains the high gas economy energy prices

[12] Confidential Appendix G contains the low gas and economy energy prices

4. Extreme Summer/Winter

- Investigated the impact extreme summer and winter conditions would have on the Preferred portfolio
- Base peak demand and annual energy forecasts, adjusted July and December 2030 for extreme conditions
- Reduced wind generation by 10% in July and December 2030
- Resource portfolio used the Preferred Plan resources
- Assumed all other modeling variables as described in "Preferred portfolio"

5. Demand Response

- Investigated the impact demand response would have on the Preferred portfolio
- Base peak demand and annual energy forecasts, 5 MW reduction beginning 2025 and 10 MW reduction in 2030 to reflect demand response impact
- Resource portfolio used the Preferred Plan resources
- Assumed all other modeling variables as described in "Preferred portfolio"

Participation in a regional market creates additional purchase and sale opportunities, which displaces some of the gas operation. In the low gas sensitivity, thermal generation increases and imports decrease, whereas the high gas sensitivity produces opposite effects. In the extreme event condition, imports are increased to meet the changing condition, although the system also has remaining thermal capacity that could ramp up to maximum output if needed. Demand response sensitivity results in reduction of storage dispatch and market purchases. Under each of these sensitivities, the Preferred portfolio was able to be dispatched to serve load under changing conditions. While this did not cause significant dispatch differences in the model, it is important to remember that the assumptions were based upon definitions from the Settlement Agreement, which are unable to fully capture any real events that may occur in the future. The Company will continue to monitor changing conditions and associated resource needs in future resource plans.

5.5: Preferred Portfolio Bids:

The Preferred Portfolio consists of three projects: Bid 248-02 150 MW Wind Facility, Bid 248-19 Battery Storage, and Bid 114-05A Solar facility ("Preferred Bids"). All three projects within the Preferred Portfolio take advantage of the IRA. Below is a description of each bid proposal.

5.5.1: Bid 248-02 150 MW Wind Facility

Bid 248-02 is a 150 MW wind facility located in Kit Carson County near Burlington Colorado built by a developer with significant experience. This location will add geographic diversity to the Company's system to support reliability, as the Company has no generation capacity in this portion of the state. Bidder 248 stated in their bid that the project pricing assumes the project qualifies for Production Tax Credits under the Inflation

Reduction Act. Table 5-5 and 5-6 below provide a summary of the bid and its economic and non-economic scorecard and rank.

Table 5-5 - Bid 248-02 Summary

Bid Number	Bidder Company	Project Name	Technology	Location	Nameplate Capacity (MW)	COD Year	Contract Type
248-02	[redacted]		Wind	Kit Carson	150	2027	PPA

Table 5-6: Bid 248-02 Scorecard

Bid No.	Economic Score	Non-economic Score	Total Score	Rank
248-02	[redacted]			

In addition to the Company's economic assessment, the Company performed an assessment of economic development benefits of this project by using the IMPLAN software. The Company estimates the economic impact to be $146 million. Hundreds of construction jobs will be needed to build the facility. In addition, the ongoing operations and maintenance of the facility will facilitate additional job growth. The local taxing authorities will also see significant benefits.

The Company recommends including bid 248-02 in the Preferred Portfolio as it supports geographic diversity of generating resources and contributes to achieving higher levels of emissions reductions. However, there are transmission risks associated with all bids on third-party transmission systems. As noted previously in Section 4.2, the RFP required that all bidders that rely on third-party transmission service for delivery of the project energy to the Company's customers would be responsible for procuring firm point-to-point transmission service for the full capacity amount of the project. The Company reviewed the currently posted availability from bids that would require third-party transmission service and noted that there is not sufficient available transmission capacity to deliver the full project capacity to the Company's transmission system. However, both third-party transmission service providers have network upgrades underway that may result in sufficient transmission service once those projects are complete and additional transmission capacity is posted – but this is not certain. In light of these risks, the Company requests the Commission approve the inclusion of bid 248-02 in the Preferred Portfolio to allow the Company to work with the developer to determine if the risks can be mitigated.

5.5.2 Bid 114-05a 200 MW Solar Facility

Bid 114-05a is a 200 MW solar facility located in Pueblo County built by a developer with significant experience. This facility will add resource diversity to the Company's generation fleet, as the Company currently has no large-scale solar resources. Bid 114-05a is proposed to be built in an Energy Community resulting in a 10% adder to the PTCs. After accounting for the Energy Community adder and estimated tax credit transfer price, the Company expects the IRA to provide over $236 million of customer benefit from bid 114-05a. Table 5-7 and 5-8 below provide a summary of the bid and its economic and non-economic scorecard and rank.

TABLE 5-7: BID 114-05A SUMMARY

Bid No.	Bidder Company	Project Name	Technology	Location	Nameplate Capacity (MW)	COD Year	Contract Type
114-05a	[redacted]		Solar	Pueblo	200	2026	BTA

TABLE 5-8: BID 114-05A SCORECARD

Bid No.	Economic Score	Non-economic Score	Total Score	Rank
114-05a	[redacted]			

In addition to the Company's economic assessment, the Company performed an assessment of economic development benefits of this project by using the IMPLAN software. The Company estimates the economic impact to be $9 million. Hundreds of construction jobs will be needed to build the facility. In addition, the ongoing operations and maintenance of the facility will facilitate additional job growth. The local taxing authorities will also see significant benefits. [redacted]

5.5.3: Bid 248-19 50 MW Battery Storage Facility

Bid 248-19 is a 50 MW solar facility located in Pueblo County built by a developer with significant experience. This project will add resource diversity to the Company's system to support reliability, as the Company currently has no large battery storage resources in its generation fleet. By taking advantage of the IRA's provisions allowing ITC on energy storage, transferability, and opting out of normalization, the Company expects Bid 248-19 to provide approximately $36 million of customer benefit over the first ten years of the project. Table 5-9 and 5-10 below provide a summary of the bid and its economic and non-economic scorecard and rank.

TABLE 5-9- BID 248-19 SUMMARY

Bid NO.	Bidder Company	Project Name	Technology	Location	Nameplate Capacity (MW)	COD Year	Contract Type
248-19	[redacted]		Energy Storage	Pueblo	50	2027	BTA

TABLE 5-10: BID 248-19 SCORECARD

Bid No.	Economic Score	Non-economic Score	Total Score	Rank
248-19	[redacted]			

In addition to the Company's economic assessment, the Company performed an assessment of economic development benefits of this project by using the IMPLAN software. The Company estimates the economic impact to be $32 million. Hundreds of construction jobs will be needed to build the facility. In addition, the ongoing operations and maintenance of the facility will facilitate additional job growth. The local taxing authorities will also see significant benefits. [redacted]

Bid 248-19 carries unique risks [redacted]

[redacted]

5.6: Reasonable Cost of Utility Ownership

The CEP Statute allows the utility to own a target of fifty percent[13] of the energy and capacity associated with the clean energy resources. Specifically, C.R.S. 40-2-125.5(5)(b) states:

> The qualifying retail utility **shall utilize a competitive bidding process**, as defined by the commission in rules, to procure any energy resources to fill the cumulative resource need derived from the electric resource plan and the clean energy plan in subsection (4)(a)(III) of this section. The commission **shall allow the qualifying retail utility**, inclusive of any ownership by its affiliates, **to own a target of fifty percent** of the energy and capacity associated with the clean energy resources and any other energy resources developed or acquired to meet the resource need, as well as all associated infrastructure, if the commission finds the cost of utility or affiliate ownership of the generation assets **comes at a reasonable cost and rate impact**. Utility ownership may come from utility or affiliate self-builds, build-transfers from independent power producers, or sales of existing assets from independent power producers or similar commercial arrangements. Nothing in this subsection (5)(b) alters the commission's authority under subsection (4)(d) of this section.

The Company utilized a competitive bidding process that resulted in a highly competitive bids, including bids for utility ownership. The Company evaluated all bids consistently throughout the entire evaluation process, which was overseen by the Independent Evaluator. Through this process, the Company is proposing two utility ownership bids, bid 114-05a and 248-19.

Bid 114-05a is highly competitive and was consistently selected during the capacity expansion modeling, showing up in five of the six portfolio scenarios without any added ownership constraint.

Bid 248-19 is [redacted]

[13] In the Public Service Company of Colorado CEP proceeding (Proceeding No. 21A-0141E), the Commission held that SB 19-236 does not in any way set a floor or a ceiling for Company ownership. See Decision No. C24-0052 at Footnote 96. The Commission found merit in having "balanced levels of PPA and Company-owned resources," which Black Hills believes the preferred portfolio has.

[redacted]

The Utility owned projects will provide an estimated $270 million of tax benefits to customers over a ten-year period. The modeling approach for Phase II assumes PTCs are claimed on solar projects and passed to customers as they are generated over 10 years, and assumes ITCs on energy storage with an election out of the normalization rules. The modeling also assumes the sale of all ITCs and/or PTCs using the IRA Transferability provisions for all Company-owned eligible resources. The IRA Transferability provisions eliminate the DTA associated with unused PTCs. Customers benefit from not paying the carrying cost of the DTA while receiving the immediate benefit of the tax credits as they are generated net of the transfer discount and related transaction costs. The modeling used for Phase II assumes all tax credits are sold at price determined by multiplying [redacted] times the tax credit to be sold. The Company developed the estimated transfer price based on discussion with its peers, advisors, and publicly disclosed sales.

Bid 114-05 is located in an area that qualifies for the IRA's Energy Community which generates an additional ten percent of production tax credits. The Company estimates the average annual tax savings to customers is approximately $24 million per year, for a total ten-year savings estimate of $236 million.

The Company estimates the average annual tax savings to customers for bid 248-19 is approximately $3.5 million per year, for a total ten-year savings estimate of $35.8 million.

The Company's Phase II Preferred Plan produces an overall Net Present Value Revenue Requirement of approximately $972 million, which is less than the estimated Phase I NPVRR of $1,567 million. This further supports the Company's preferred plan results in a reasonable cost to customers.

Finally, as shown in Figure 6-1 below, and discussed in detail below in section 6, the Company's Preferred Plan, inclusive of utility ownership, results in reasonable rate impacts to customers. The Company is forecasting stable and slightly declining average residential bills as a result of this CEP.

5.7: Back-Up Bids

Due to the successful outcome of the 2030 Ready RFP, the Company is pleased to present multiple back-up bids, in the event one or more of the Preferred Bids fail. The Company believes it is important to receive Commission approval of back-up bids because there is a risk that the Preferred Bid fails to perform or otherwise has an unsuccessful process to negotiate an agreement. In this circumstance, the Company could then replace the Preferred Bid with the recommended back-up bid. If the first back-up similarly fails, then the Company could then replace that bid with the back-up bids. This approach was approved by the Commission in Phase I[14].

[14] Settlement Agreement: Section 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.

The Company also believes it is important to reduce the likelihood of selected bids failing. To that end and in collaboration with the IE, the Company issued a notice on March 27, 2024 to all remaining bidders requesting they confirm 1) if their bid is selected they are prepared to move forward with contracting and 2) that they will be able to post the required security once a contract is executed. Bidders for the recommended bids in all portfolios confirmed they will proceed as required if selected.

The Company's approach to recommending the back-up bids is to present the next most competitive bids by resource type and recommend those bids. Though the Company used this approach, because of the high competitiveness of the bids, acquisition of any of the recommended bids (i.e., Preferred Bids and back-up bids) is an appropriate outcome to further the public interest as the backup bids as the backup bids will still allow the Company to achieve the clean energy plan goals.

Commission approval of the recommended back-up bids will assist the Company in the negotiation process with the Preferred Bids, and it will provide necessary assurance to the Company that if the Preferred Bids fails the Company can continue to with its Preferred Portfolio.

The Company intends to actively negotiate with all Commission approved bids (i.e. Preferred Bids and back-up bids) to ensure customers fully benefit from the competitive solicitation process. The Company anticipates additional outside legal expenses required to negotiate contracts with all bidders. The Company intends to recover this cost through the regulatory asset the Commission previously approved.

5.7.1: Wind Back-Up Bid

None of the wind bids received were directly connected to the Company's transmission system. To avoid the transmission risks described above, the Company is recommending a solar backup bid. Bid 248-01 is a 100 MW solar facility located in Pueblo County built by the same developer and contracting structure as the preferred wind bid. This location will add resource diversity to the Company's system to support reliability, as the Company currently has no large-scale solar resources in its generation fleet. This bid ranked second in the economic and non-economic scorecard.

TABLE 5-11: BACK UP WIND BIDS

Bid No.	Bidder Company	Project Name	Technology	Location	Nameplate Capacity (MW)	COD Year	Contract Type	Scorecard
248-01	[redacted]	[redacted]	Solar	Pueblo	100	2026	PPA	[redacted]

While this bid is the [redacted] ranked solar bid, the RESOLVE model selected this bid in Portfolio 6 – Local Economic Development. The Company reviewed the results of Portfolios 6 – Local Economic Development which is made up of bids 114-05a, 248-01, and 245-01 and is confident if bid 248-01 is acquired in place of bid 248-02 the objectives of the CEP can be achieved at a reasonable cost.

5.7.2: Solar Back-Up Bids

The Company has identified three back up solar bids. Bid 223-01b, Bid 223-03b, and 190-05a. These bids represent the [redacted] ranked solar BTA bids that would fit within the preferred portfolio. Bid 223-01a and Bid 223-03b are both 100 MW solar facilities, thus the combination of these two bids would represent a similar replacement for the preferred bid if needed. These projects are built by a developer with significant experience and would add additional geographic diversity due to their separate locations. Bid 190-05a is a 199 MW solar facility located in Pueblo County built by a developer with significant experience.

TABLE 5-12: BACK UP SOLAR BIDS

Bid Number	Bidder Company	Project Name	Technology	Location	Nameplate Capacity (MW)	COD Year	Contract Type	Scorecard
223-01b	[redacted]	[redacted]	Solar	Otero County	100	2028	BTA	[redacted]
223-03b	[redacted]	[redacted]	Solar	Otero County	100	2028	BTA	[redacted]
190-05a	[redacted]	[redacted]	Solar	Pueblo County	199	2027	BTA	[redacted]

5.7.3: Battery Storage Back-Up Bid

The Company has identified one back up battery storage bid, bid 245-01. Bid 245-01 is a 50 MW battery storage facility located in Freemont County built by a developer with significant experience. This project will add resource diversity to the Company's system to support reliability, as the Company currently has no large-scale battery storage resources in its generation fleet. While this bid was the [redacted]

Table 5-13: Back up Battery Storage Bids

Bid Number	Bidder Company	Project Name	Technology	Location	Nameplate Capacity (MW)	COD Year	Contract Type	Scorecard
245-01	[redacted]		Battery Storage	Fremont County	50	2027	BTA	[redacted]

5.8: Alternative Portfolio Optimizations

As agreed to in Settlement, the Company used the annuity method as a bookend optimization for the following portfolios: Base ERP (Portfolio 2), CEP (Portfolio 3), 40% Ownership (Portfolio 4), and Geographic Diversity (Portfolio 5). In each of these portfolios, wind bid 248-02, solar bid 114-05a, and storage bid 245-01 were selected. These are the same bids selected by the capacity expansion model for the CEP portfolio using the replacement chain method. Using the annuity method did not result in any additional bids being selected or higher emission reductions than the Preferred Portfolio. Table 5-14 below identifies the bids selected in each portfolio using the annuity method.

Table 5-14: Annuity Method Portfolios

Technology	Base ERP	CEP	40% Ownership	Geographic Diversity
Wind	248-02	248-02	248-02	248-02
Solar	114-05a	114-05a	114-05a	114-05a
Storage	245-01a	245-01a	245-01a	245-01a

6: Cost Recovery

In this section of the 120-day report the Company discusses the proposed cost recovery framework for its preferred portfolio. This section provides a summary of the legislative framework for cost recovery of the Company's Clean Energy Plan, discusses the provisions in the Settlement Agreement that require the Company to present option for the Commission to consider, and present the Company proposed cost recovery proposals**.**

6.1: Clean Energy Plan Legislative Cost Recovery Framework

Section 40-2-125.5(5), C.R.S. sets forth the primary parameters concerning the Clean Energy Plan Rider ('CEPR") and cost recovery. Among other things, the legislation:

- Authorizes a maximum electric retail rate impact of 1.5 percent of customers' total annual electric bills for implementation of the approved additional CEP activities;
- Allows a utility to collect revenues for additional clean energy plan activities through a rider – i.e., a CEPR, which may be established "as early as the year following approval" of a CEP, and at a level "no greater than the maximum electric retail rate impact";
- Provides that the CEPR "shall afford" cost recovery treatment "up to the maximum electric retail rate impact until the first-rate case following the final implementation of the clean energy plan, at which time the remaining costs and savings associated with the [CEP] will be incorporated into base rates";
- Permits the CEPR to be used to recover costs of a CEP's capital investments and related expenses, exclusive of:

  (i) Fuel and transmission costs;
  (ii) Costs associated with the capital investments and operations and related expenses needed to satisfy the utility's ERP resource needs, without the CEP;
  (iii) Incremental costs of eligible energy resources recovered through the RESA; and
  (iv) Incremental costs of any clean energy resources and directly related interconnection facilities that are recovered through RESA funds.

Additionally, § 40-2-125.5(4)(VIII) C.R.S. authorizes a utility to apply up to half of the funds collected annually through its RESA, plus any accrued funds, "to recover the incremental cost of clean energy resources and their directly related interconnection facilities." The statute further provides that the utility "may account for these funds in calculating the cost of the plan."

6.2: Phase I Settlement Agreement- Cost Recovery Options

In Phase I, the Settling Parties recognized the importance of managing costs associated with the Company's CEP. The Settling Parties agreed that it is appropriate for the Commission to determine the appropriate cost recovery structure for the Company's CEP as part of Phase II of this Proceeding.

To accomplish this, the Company agreed to present, as part of its 120-Day Report, several cost recovery options for its Preferred Portfolio, 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. The 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.

The specific cost recovery options are defined in paragraph 53 in the Settlement Agreement, which states the Company presents, at a minimum, the following options:

> ¶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.

If the CEPR is needed to fund the CEP, the Settling Parties agreed 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. 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.

6.2.1: CEP Additional Cost

As discussed in § 40-2-125.5(5), C.R.S. the Company is allowed to recover the "additional clean energy plan activities" through the CEPR. To determine the "additional" CEP activities, the Company compared the resource acquisitions associated with its Preferred Plan (CEP) to Portfolio 2: Base ERP with SC-GHG-Least Cost Portfolio, consistent with the Settlement Agreement.[15] The purpose of Portfolio 2 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 achieve the Clean Energy Plan Goals.

The results of Portfolio 2 and the Company's Preferred Portfolio are shown in the table below. Portfolio 2 does not achieve at least an 80% reduction in emissions, thus Portfolio 2 is ineligible to be considered a Clean Energy Plan, and a CEPR is thereby needed to fund the additional cost to achieve the CEP. The Company's Preferred Portfolio meets the CEP goals. As shown in the table below, the additional resources needed to achieve the CEP goals is the 150 MW Wind project. Thus, the cost associated with Bid 248-02 are "additional" costs and eligible for cost recovery through the CEPR. As shown in Table 6.2.1, the revenue requirement associated with the Preferred Portfolio Bid 114-05a (200 MW solar) and 248-19 (50 MW storage) will be included in the Company's Energy Cost Adjustment ("ECA").

TABLE 6-1: ADDITIONAL CEP ACTIVITIES

Resources	Portfolio 2	Preferred Portfolio	Cost Recovery Mechanism
Wind	N/A	150 MW (Bid 248-02)	CEPR
Solar	200 MW (Bid 114-05a)	200 MW (Bid 114-05a)	ECA
Battery Storage	50 MW (Bid 245-01a)	50 MW (Bid 248-19)	ECA
Total	250 MW	400 MW	

6.2.2: Cost Recovery Options

Consistent with the Settlement Agreement, the Company prepared four cost recovery scenarios, which include variations of the CEPR, use of RESA surplus funds, and modifications to the RESA surcharge. The Company then prepared estimated bill impacts associated with each scenario. The use of the RESA surplus does not have

[15] See Settlement Agreement (Hearing Exhibit 118) at paragraph 12.2.

an immediate impact on customer bills but rather impacts the value of the CEPR regulatory asset balance in 2030.

To forecast the cost, the Company examined the costs associated with the RES Plan, fuel and purchase power costs that are recovered through the ECA, and the estimated annual revenue requirements associated with the two new utility owned projects. The Company did not forecast changes in base rates or other surcharges such as the Demand Side Management Cost Adjustment or the Transportation Electrification Plan Rider. Base rates and other surcharges will fluctuate year to year, but the intent of this customer bill impact analysis is to provide estimated customer bill impacts that are directly related to this Clean Energy Plan.

To estimate the fuel and purchase power costs (which are the majority of costs included in the ECA), E3 conducted analysis using PLEXOS which simulates the dispatch of the Company's Preferred Plan and existing resources through 2030. This allows the Company to get an estimate of the total fuel and purchase power costs that would be included in the ECA. To forecast the RESA costs, the Company utilized the RESA forecast which was updated and included in the Phase I settlement Agreement. As discussed above, Bid 248-02 is considered the "additional" CEP cost, thus the annual PPA expenses are included in the CEPR. Since Bid 248-02 is interconnected on a third-party transmission line, additional firm point to point costs will be incurred. These costs are not eligible for CEPR, thus the Company included them in the ECA rider forecast. For bids 114-05a and 248-19, the Company calculated the annual revenue requirement for each facility, which includes all associated expenses, ownership costs, and annual tax savings that are passed on to customers.

The four cost recovery scenarios are provided as Appendices K1-4 and are summarized below.

Scenario 1

1. Recovery occurs only through the existing RESA & ECA recovery mechanisms.
2. The RESA rate remains at the current 2.0% for the years 2024 through 2031.
3. There is no transfer of the RESA balance.
4. Cost recovery does not occur through a CEPR rider. The resulting impact is a sizable increase in a deferred regulatory asset.

Scenario 2

1. Recovery occurs only through the existing RESA & ECA recovery mechanisms.
2. The RESA rate decreases to 1.5% in 2025 and remains at 1.5% through 2031.
3. There is no transfer of the RESA balance.
4. Cost recovery does not occur through a CEPR rider. The resulting impact is a sizable increase in a deferred regulatory asset.

Scenario 3

1. Recovery occurs through the RESA, ECA and CEPR.
2. The CEPR rider is set at 1.5% in 2025 and remains at 1.5% through 2031.
3. The RESA rate remains at the current 922.0% for years 2024 through 2031.
4. 50% of the RESA balance is transferred to the CEPR balance at the end of 2026.

Scenario 4

1. Recovery occurs through the RESA, ECA and CEPR.
2. The CEPR rider is set at 1.5% in 2025 and remains at 1.5% through 2031.
3. The RESA rate decreases to 1.5% in 2025 and remains at 1.5% through 2031.

4. 50% of the RESA balance is transferred to the CEPR balance at the end of 2026.

6.3: Proposed Cost Recovery

The Company is proposing Scenario 4 for cost recovery purposes. This scenario minimizes customer bill impacts through 2030. The average residential customer bill in March 2024 was approximately $113 and the estimated average customer bill in 2030, taking into account this clean energy plan, will fall below $105. The Company will implement a new 1.5% CEPR surcharge on all customer bills in 2025, and, at the same time, will reduce the RESA surcharge from 2% to 1.5%. Further, the Company is forecasting that its natural gas fuel cost will be reduced as a result of the CEP adding renewable energy that is expected to reduce usage of natural gas generation. The net result of these changes lead to overall stable customer bills through 2030 from the CEP.[16]

6.3.1: Clean Energy Plan Rider ("CEPR")

Since Portfolio 2 does not achieve the emission reduction targets, pursuant to the Settlement Agreement and the Commission's Phase I Decision (Decision No. C23-0193), the Company selected a portfolio of resources that does achieve the emission reduction targets. Therefore, the CEPR is needed to recover the additional cost associated with the Preferred Portfolio. As discussed above, bid 248-02 is identified as the additional resource that is required to meet the CEP.

The Company is proposing to implement the 1.5% CEPR surcharge on January 1, 2025 consistent with Section 40-2-125.5(5)(a)(II), which states the CEPR may be established as early as the year following approval of the clean energy plan. The Company is hoping to receive Commission approval of Phase II of the CEP in 2024; thus, January 1, 2025 is the earliest the CEPR surcharge may be effective.

The annual PPA cost of the wind facility is expected to exceed the revenues generated from the CEPR. Thus, the Company is forecasting an under recovery or regulatory asset of approximately $18.4 million by 2030. The Company is afforded cost recovery up to the retail rate cap until final implementation of the CEP, at which time the remaining cost will be incorporated into base rates.[17]

6.3.2: Renewable Energy Standard Adjustment ("RESA")

The Company updated the RESA cost forecast in the Settlement Agreement in Phase I. This cost forecast is based on the Commission currently approved RES plan and does not take into account future potential legislative impacts on the Company's RES Plan. Based on this cost forecast, the Company is able to reduce the RESA surcharge from 2% to 1.5%. This is consistent with the Company's approach in Phase I. The Company

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[16] This analysis is limited to the CEP and does not include rate impacts that may occur as a result of other ongoing or future proceedings.

[17] See C.R.S § 40-2-125.5(5)(a)(II).

proposes to reduce the RESA surcharge to 1.5% on January 1, 2025 to coincide with the introduction of the CEPR. This reduction will help mitigate the effects of the new CEPR surcharge.

In addition, the Company proposes to utilize the CEP statute and transfer half of the RESA surplus into the CEPR to help fund the additional cost of the CEP. The Company proposes this transfer to occur in 2027 when the wind facility is completed, and costs have been incurred. C.R.S 40-2-125.5(4)(a)(VIII) states:

> 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.

6.3.3: Electric Cost Adjustment ("ECA")

The Company estimated the fuel and purchase power cost from the PLEXOS model performed by E3. This analysis provides an overall cost estimate of the fuel and purchase power cost that would normally be included in the ECA. As expected, the inclusion of the wind and solar projects will displace natural gas fired generation and thus reduce our overall cost of natural gas.

The Company proposes to recover the annual revenue requirement associated with bids 114-05 and 248-19 in the ECA for a period of 10 years. This treatment is similar to the Company's recovery mechanism associated with its PeakView Wind Facility and similar to recovery treatment the Commission has authorized for Public Service Company of Colorado for two of their wind facilities. During the tenth calendar year of operation (2037), Black Hills will file an application setting forth its proposal for maintaining (i.e., through the ECA) or for changing the method of recovery of the costs (e.g., the Company may propose including the cost through base rates). This filing will ultimately determine the appropriate method of cost recovery going forward.

The Company will perform a standalone pro-forma revenue requirement analysis for each of the first ten calendar years of commercial operations of bid 114-05 and 248-19 beginning in 2027. The pro-forma revenue requirement will be included in the ECA for current cost recovery, which will be followed with a true-up using actual cost. The Company has performed an illustrative revenue requirement calculation that is provided as Appendix K5-6. This revenue requirement template will be used to calculate the annual revenue requirement for inclusion in the ECA.

Bid 114-05 is a 200 MW solar facility located in an area that qualifies for the IRA's Energy Community, which generates an additional ten percent of production tax credits. The Company estimates the average annual tax savings to customers is approximately $23 million per year, for a total ten-year savings estimate of $236 million.

The Company estimates the average annual tax savings to customers for bid 248-19 is approximately $3.5 million per year, for a total ten-year savings estimate of $35.7 million.

6.3.4: Performance Incentive Mechanism ("PIM")

The Commission directed the Company and parties to engage in a stakeholder process for the development and submission of two PIMs: (1) an emission reduction PIM and (2) a utility-owned generation PIM. The Commission established the following schedule:[18]

- The stakeholder process will be initiated by the Company 15 days after the filing of the 120-Day Report. (May 2, 2024)
- The Company will file the PIM proposals with the Commission 60 days after the filing of the 120-Day Report with supporting testimony. (June 17, 2024)
- 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. 22A-0230E) that would like to comment on the PIM proposal: (July 17, 2024)
    - If no protests are filed, the Commission attempt to rule on the PIMs within 60 days after filing of the PIM proposal, schedule permitting. (August 16, 2024)
    - If protested, the Commission will attempt to conduct a limited and expedited hearing within 30 days of comment deadline, schedule permitting. (August 16, 2024) If feasible, the Commission will attempt to issue a decision on any PIM within 30 days of such hearing. (September 15, 2024)
- There will be no discovery process regarding the PIM proposals.

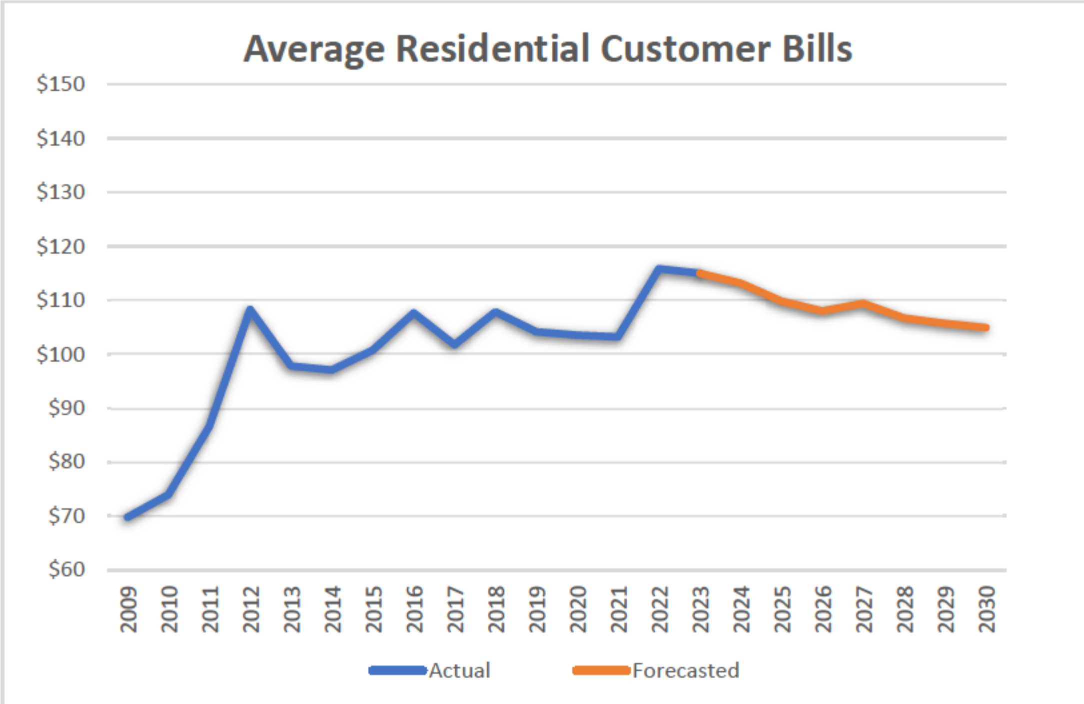
The Company will work with stakeholders and will present a PIM for the Commission's consideration and approval.

6.3.5: Estimated Bill Impact

The current average residential monthly bill as of March 1, 2024, is $113.15 per month. The Company estimated the bill impacts associated with the Preferred Portfolio and the preferred cost recovery scenario as described above. This bill impact analysis compares current rates and rates that will be in place on January 1, 2025, using a 1.5 percent RESA, and an ECA based on the projections used for modeling. While customers' bills will increase on January 1, 2025 when the CEPR begins collections at 1.5 percent, there will also be bill reductions as a result of the expiration of the Extraordinary Gas Cost Recovery Rider (which is recovering Winter Storm Uri costs) and lower projected ECA costs. Compared to average bills based on rates effective March 1, 2024, the Company is projecting a net reduction to the average residential monthly bill of $5.16, or -4.56 percent, on January 1, 2026. Ultimately, residential customers will see a total average monthly bill decrease of 7.28 percent by 2030 compared to current rates from the CEP. The graph below represents the average residential monthly bill through 2030.

[18] See Decision No. C23-0193 at paragraph 58.

FIGURE 6-1: AVERAGE RESIDENTIAL CUSTOMER BILL



7: Conclusion

Black Hills has selected the most cost-effective bids from a selection of very competitive bids. Using a thorough and fair evaluation process the Company has determined that the Preferred Portfolio will provide the most economic benefit for Black Hills' customers, while also increasing the Company's percentage of renewable generation resources. This portfolio of bids will also increase technological and geographical diversity of the Company's resources. It will significantly further carbon dioxide emission reductions associated with the Company's generation system, pushing Colorado forward in its clean energy transition. Southern Colorado will also benefit as whole from the economic development opportunities associated with constructing and maintaining the solar and battery storage projects.

C.R.S. 40-125.5(4)(d) states the Commission shall approve the Company's CEP if it finds it to be in the public interest and consistent with the clean energy plan targets. In evaluating the Company's CEP, the Commission shall consider the following:

> **(I)** Reductions in carbon dioxide and other emissions that will be achieved through the clean energy plan and the environmental and health benefits of those reductions;
>
> **(II)** The feasibility of the clean energy plan and the clean energy plan's impact on the reliability and resilience of the electric system. The commission shall not approve any plan that does not protect system reliability.
>
> **(III)** Whether the clean energy plan will result in a reasonable cost to customers, as evaluated on a net present value basis. In evaluating the cost impacts of the clean energy plan, the commission shall consider the effect on customers of the projected costs associated with the plan as set forth in subsection (4)(a)(VI) of this section as well as any projected savings associated with the plan, including projected avoided fuel costs.

Regarding reductions in emissions, the Company's Preferred Plan reduces emissions by 89% by 2030, exceeding the goal of 80% by 2030. The Company used the required CDPHE workbooks to evaluate the emission reductions resulting from the Preferred Plan.

Regarding feasibility, the Company has proposed several back up bids in the event the primary bid fails. These reasonable back up bids will allow the Company to negotiate with multiple developers and projects adding to the feasibility of successful contract negotiations and project development.

Regarding reliability and resilience, modeling results indicate the system will remain reliable and resilient with the existing 420 MW of efficient, dispatchable natural gas generation supporting the addition of the Preferred Portfolio. The capacity contributions from the wind, solar, and storage projects selected in the Preferred Plan achieve the planning reserve margin requirement established in the Settlement Agreement. Additionally, E3 performed operability analysis on the Preferred Portfolio to reveal any challenges the Company may experience in meeting demand due to generation variability within a higher renewable system. The study used production cost simulation across the sensitivities described in Section 5.4 above for every year between 2026 and 2030. E3's Technical Report, Appendix H, contains additional detail on this analysis.

Regarding reasonable cost to customers, the Preferred Plan's NPVRR is approximately $972 million, which is $595 million less than the estimated Phase I NPVRR of $1,567 million originally estimated in Phase I. The Company has prepared a customer bill impact analysis demonstrating the Preferred Plan's effect on customer bill. As shown in Figure 6.3.5 above, the Average Residential Bill remains stable through 2030 from the CEP. The 2030 Ready Preferred Portfolio will displace natural gas generation and save customers natural gas fuel cost. In addition, due to the IRA's transferability of tax credits, customers will receive $271.8 million of savings through the PTC and ITC tax credits.

For all these reasons, the Company recommends the Commission find that its Preferred Portfolio is in the public interest and requests the Commission authorize the Company to pursue these bids. Further, Black Hills has also selected back-up bids, for which it also seeks Commission approval in the event the Company is unable to proceed with its Preferred Bids.

Our 2030 Ready Preferred Portfolio provides a long-term outlook for a clean energy future. As an early leader in Colorado, transitioning away from coal combustion generation and toward clean energy resources through the Peak View and Busch Ranch wind facilities, Black Hills' 2030 Ready Plan is built upon years of phased-in renewable generation developments that will assist the Company in exceeding the State of Colorado's greenhouse gas emission goals at a reasonable cost while supporting the continued reliability and resiliency of our system.