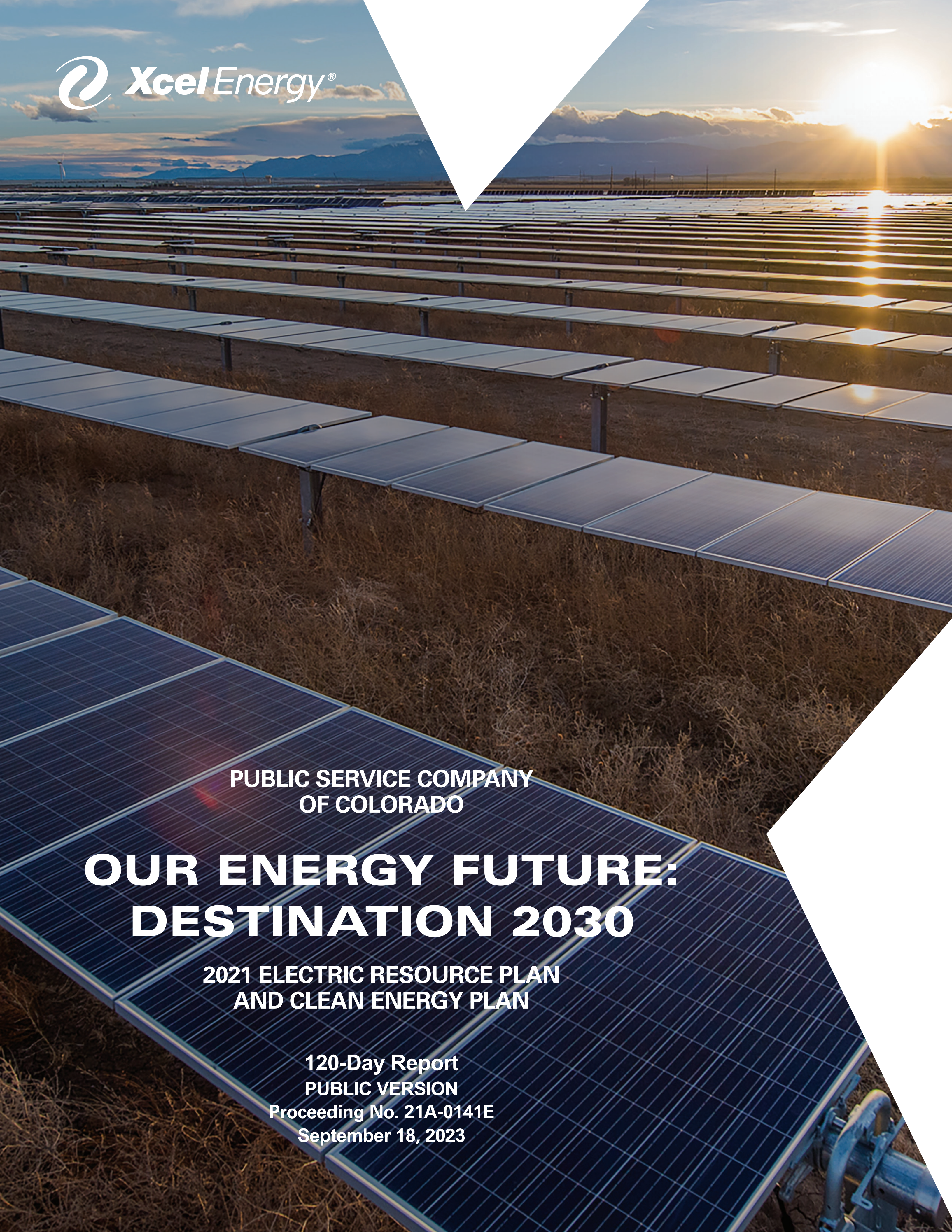

Xcel Energy®

PUBLIC SERVICE COMPANY
OF COLORADO

OUR ENERGY FUTURE: DESTINATION 2030

2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN

120-Day Report
PUBLIC VERSION
Proceeding No. 21A-0141E
September 18, 2023

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1.0 Executive Summary

This "120-Day Report" presents Xcel Energy's recommended portfolio of resources ("Preferred Plan") to achieve the goals of the Clean Energy Plan.

The Clean Energy Plan is an important step in the energy transition in Colorado. It will implement the State of Colorado's clean energy policy directives, provide significant new clean energy to customers, and drive investment and economic development across the State. The Clean Energy Plan achieves these objectives while balancing customer expectations for reliability and affordability by advancing affordable clean energy options and assuring investments in system reliability during the transition.

Since 2005, our Colorado system has been transformed, providing customers with a 51 percent reduction in carbon emissions while serving Colorado's growing economy. Our Preferred Plan is the next step in that process and propels the power sector and the State of Colorado towards the sector-specific and statewide emissions reduction targets established by the General Assembly.

The Preferred Plan is the result of an extensive process to identify the most effective path to achieve the long-term goal of carbon-free electricity while balancing affordability and reliability. As part of this process, more than 1,000 competitive bids were received and analyzed to identify the optimal portfolio.

Under the Preferred Plan, Public Service Company of Colorado ("Public Service" or the "Company") will exit coal by the end of this decade, build an unprecedented amount of wind and solar energy, reduce greenhouse gas emissions by more than 80% from 2005 levels, and maintain a reliable grid, all with an average annual rate impact of approximately 2.25%, in line with the rate of inflation.

To get there, the plan features approximately:

- 3,400 MW of wind resources,
- 1,400 MW of solar combined with storage resources,
- 1,100 MW of standalone solar resources,
- 600 MW of standalone storage resources; and,
- 600 MW of strategically located natural gas resources.

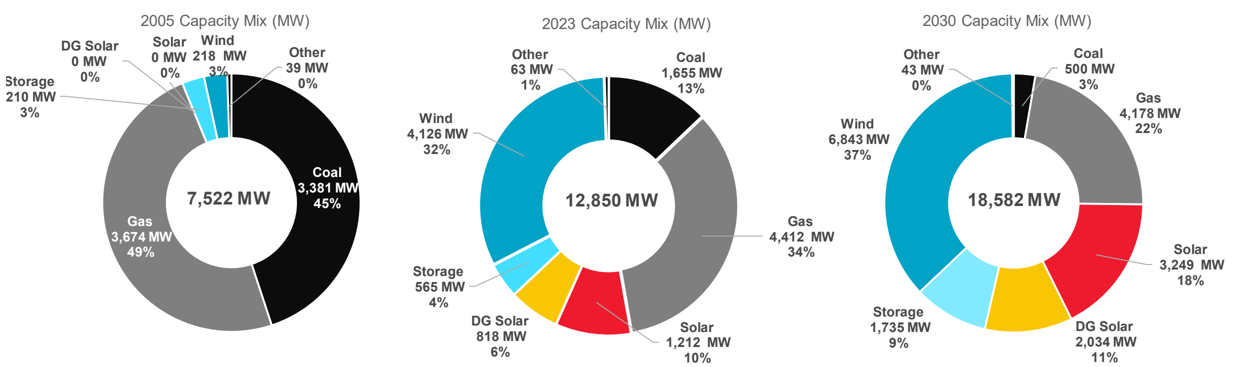
The Preferred Plan is designed to maximize the opportunities presented by both the Inflation Reduction Act of 2022 ("IRA") and Colorado's Power Pathway Project ("CPP"). It puts the IRA to work, bringing billions of dollars in federal support to Colorado, and delivering these benefits to the doorsteps of customers in the form of new clean energy options. More specifically, the plan brings $10 billion in IRA benefits to customers, $14 billion in energy investment to Colorado, and $2.5 billion in tax benefits alone to local communities in the coming decades. The CPP was proactively planned by the Company and approved with foresight by the Commission to provide new clean energy opportunities to capture federal tax incentives by providing deeper reach into Colorado clean energy zones, and to bring the cleanest and most affordable projects directly to our customers. Moreover, it works in concert with approximately $2.82 billion in additional transmission investment under this plan to facilitate the delivery of clean energy to our customers, prepare the system for continued future change, and maintain a reliable system throughout the state while the clean energy transition continues.

As explained in this Report, we believe the Preferred Plan is transformational: achieving increasingly clean energy service with high reliability and affordable cost. As with any transformation, there remains significant work to be done to complete permitting, put steel in the ground, and manage significant change in the system. We will need a broad swath of the energy industry to do it; indeed, independent power producers ("IPPs") have a role in developing every single megawatt ("MW") of the 6,545 MW of renewable projects in the Preferred Plan. And we are confident that, by working together with the Commission and policymakers, we can achieve the objectives outlined in the Plan and continue to demonstrate why Colorado is a model for others to follow.

The Preferred Plan – By the Numbers

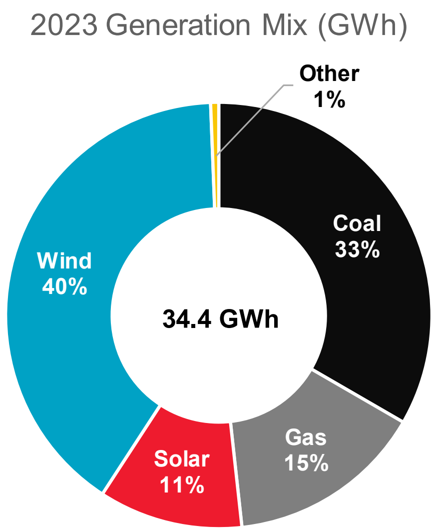
In building the Preferred Plan, we advanced hundreds of project options to computer-based modeling. Coordinating closely with the Independent Evaluator, we worked through different portfolios to stress test them for reliability, both local and systemwide, and considered the ability of different projects to come to fruition. The results are set forth below:

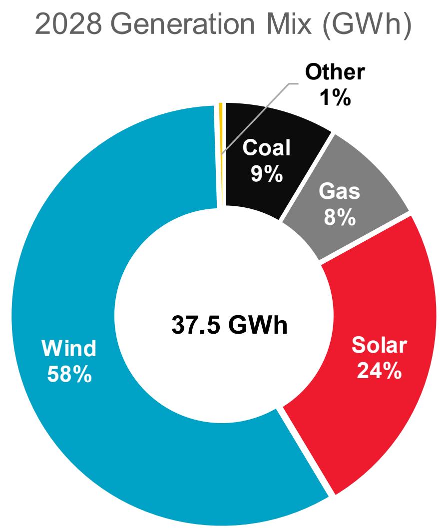
<u>System Capacity Mix: 2005 – 2030[1]</u>



[1] The 2030 Capacity Mix is estimated and will be finalized in the upcoming Just Transition Plan which will plan for and select additional resources in the 2029-2031 timeframe. All coal capacity will be retired by 2031 under the terms of the approved Updated Settlement Agreement in this current resource plan.

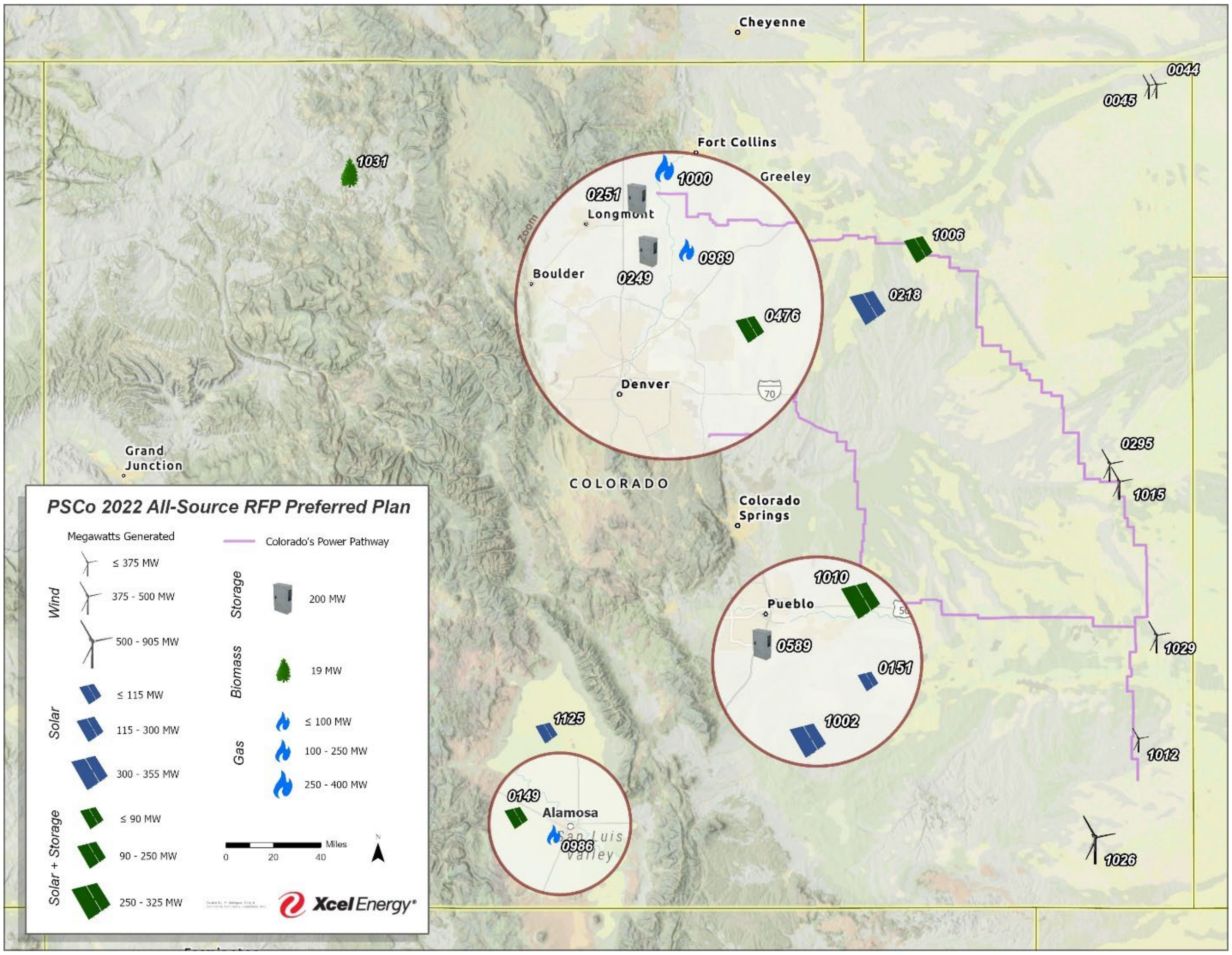
Estimated Energy Mix Changes Under the Preferred Plan





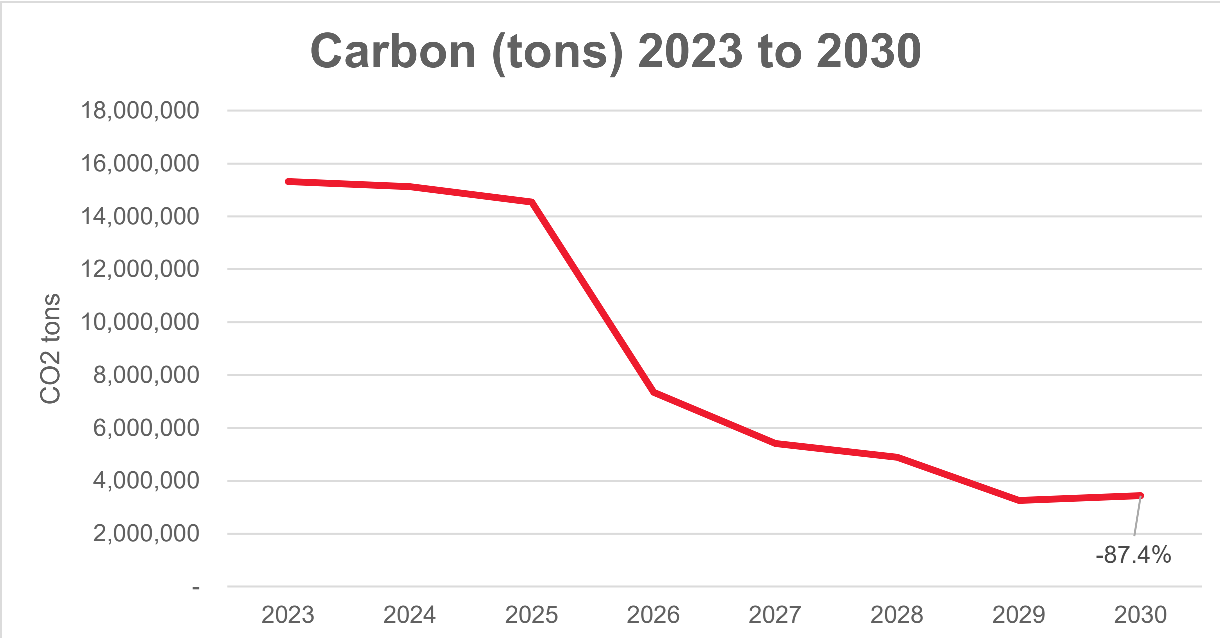
By 2028, more than 80 percent of our electricity will come from renewable energy sources. And by the end of 2030, we will retire our last coal unit (Comanche 3), leaving the Company's system entirely coal-free. The Preferred Plan is a critical step in achieving these goals with additions of clean energy in the coming years, and the resources selected in our Preferred Plan are spread throughout the State.

Preferred Portfolio Generation Geographic Locations



The modeled emissions reductions in our Preferred Plan exceed the state targets:

Energy Transition: Modeled Emissions Reduction Under the Preferred Portfolio[2]



The Preferred Plan Balances Reliability, Costs, Delivery Risk, and State Policy

The Company tested the Preferred Plan extensively, including against three other key portfolios, which provide three lenses to illustrate the value of the Preferred Plan. The lenses are a "business as usual" scenario, a "least cost plan" scenario, and a "no gas" scenario.

The Preferred Plan will achieve greater emissions reductions while maintaining a reasonable cost increase as compared to a "business as usual" scenario that does not accelerate the retirement of all of the Company's coal plants, does not include the social cost of carbon, and does not meet 2030 emissions targets.[3] Over an extended horizon through 2055, the Preferred Plan costs approximately $44.2 billion on a net present value basis, compared to $43.3 billion for the "business as usual" scenario. Notably, the "business as usual" scenario is sure to require substantial future investments to make up for lost time in emissions reduction if those investments are not pursued now.

[2] Modeled emissions reductions will differ from actual emissions because the model has perfect foresight on system conditions due to "normal" weather. 2029 and 2030 consist of generic resources and not actual bids pursuant to the acquisition period for this plan established by the Commission.
[3] This is precisely the analysis required under the statutory parameters established by the General Assembly in Senate Bill 19-236.

We also developed an "informational least cost plan" that meets the 2030 emissions reduction targets through the accelerated coal plant retirements but does not meet strategic and essential local reliability needs nor address just transition considerations. The cost differential between the Preferred Plan and the least cost plan is $207 million on a net present value basis through 2055 – a difference of 0.5%. For the additional investment, the Preferred Plan achieves the following objectives compared to the least cost plan:

- Advances a Just Transition*.* The Preferred Plan drives investment and maintains jobs in communities affected by coal plant retirements.

- Addresses San Luis Valley Local Reliability Needs*.* The Preferred Plan solves for local reliability needs through the addition of generation in the San Luis Valley in a way that the least-cost plan does not.

- Addresses Denver metro Area Reliability Considerations. The Preferred Plan provides generation support to the Denver metro area that is not accounted for in the development of the least-cost plan, rendering the Preferred Plan a more reliable portfolio as a result.

A third lens shows the value that the dispatchable resources bring to the system. We evaluated a portfolio that did not include new gas resources ("No Gas Portfolio"). The No Gas Portfolio is a substantially larger plan (11,000 MW total nameplate capacity as compared to approximately 7,200 MW in the Preferred Plan), and it also significantly increases costs to customers, reduces reliability under extreme cold and in extreme hot weather events, and increases operational risks. This No Gas Portfolio therefore represents a portfolio that, from a reliability, optionality, and cost perspective, we are unwilling to put forward as a viable approach: the risks and costs are too great. The Preferred Plan achieves the same environmental objectives with more reliability, lower operational risk, and lower costs to customers.

Conclusion

After more than three years of work to develop the CPP and this Clean Energy Plan, we recommend the Preferred Plan. This plan provides numerous clean energy options, reduces emissions, maintains reliability, and does so at low cost. The plan demonstrates a proactive and combined "Field of Dreams" transmission and generation planning approach that can be an example for the West and the country. It meets resource adequacy needs while adding thousands of megawatts of clean energy, providing workforce opportunities, supporting our communities and meeting the clean energy targets set by the General Assembly.

Untold hours of work with, and dedication from, the Commission, stakeholders, the bidding community, and the Company have led to this moment. We are proud to present this nation-leading Clean Energy Plan for the Commission's review.

The remainder of the Report proceeds as follows:

- **Section 2.0** provides a detailed overview and analysis of the Company's Preferred Plan;
- **Section 3.0** discusses model adjustments and modeling methodology updates;
- **Section 4.0** provides an overview of other Phase II portfolios developed and sensitivity analyses performed as required by the Phase I Decision;
- **Section 5.0** discusses natural gas resource considerations;
- **Section 6.0** provides an overview of transmission-related issues and the preliminary evaluation of transmission investments expected to be necessary to implement the Preferred Plan;
- **Section 7.0** provides a discussion of the bids received that meet the Section 123 criteria;
- **Section 8.0** provides a discussion of pre-construction development assets and describes the limited number of bids received that selected this option;
- **Section 9.0** describes the role of the labor economist in reviewing and scoring best value employment metrics information provided by bidders;
- **Section 10.0** provides an update on the Company's workforce transition and community assistance coordination efforts;
- **Section 11.0** provides an overview of cost recovery-related issues, including coal asset cost recovery provisions, and costs to be recovered by the Colorado Energy Plan rider; and, finally,
- **Section 12.0** summarizes next steps, future related filings, and provides a conclusion reiterating key highlights and request for approval of the Company's Preferred Plan.

2.0 Overview & Analysis of the Preferred Plan

This Section of the 120-Day Report[4] ("Report") provides a detailed discussion of key characteristics associated with the Preferred Plan described in the Executive Summary.

The Preferred Plan is the product of thousands of hours of modeling and evaluation including extensive collaboration with the Independent Evaluator ("IE"). Starting from a record-setting bid pool of over 1,000 bids received in response to the 2022 All-Source Request for Proposals ("RFP") and using Commission and General Assembly directives from Decision Nos. C22-0459 and C22-0559 (collectively, the "Phase I Decision") and Senate Bill 19-236, respectively, the Company conducted due diligence on potential projects and modeled different portfolios that could meet State of Colorado energy policy directives in a safe, reliable, and affordable manner. The Preferred Plan is the result of these efforts.

The Preferred Plan puts the IRA to work, using the regulated utility model and the well-established Colorado electric resource planning ("ERP") process to bring billions of dollars in federal support to Colorado, and delivers these benefits to the doorsteps of customers in the form of new clean energy resources. More specifically, the plan brings billions in energy investment to Colorado communities and landowners and $10 billion in IRA benefits to customers. It is also a historic plan due to not just the size of the solicitation and plan but also the diversity and robust response from the market. The Preferred Plan will propel the power sector and the State of Colorado towards the sector-specific and statewide emissions reduction targets established by the General Assembly. The Preferred Plan is expected to:

- Exceed the emissions reduction target in Senate Bill 19-236;
- Generate approximately 83% of our customer's 2028 electricity needs from clean energy resources by adding a diverse set of clean energy resources, including three types of renewables – wind, solar, and biomass – coupled with storage in standalone and solar hybrid configurations;
- Deploy over 6,500 MW of renewables and batteries, with clean energy investments in communities affected by upcoming coal plant retirements to execute on just transition commitments;
- Continue our reliability success with approximately 600 MW of strategically located dispatchable resources to support local and systemwide reliability along with additional transmission reinforcement;

[4] The Company notes that while the Commission granted three requests for an extension of the deadline to file the 120-Day Report (*see* Decision Nos. C23-0246-I, C23-0552-I and C23-0594-I), the Company maintains reference to this Report as the "120-Day Report" throughout this document given it is generally referred to as such throughout this Proceeding and in the Commission's Phase I Decision.

- Balance geographic diversity across the system with the proposed selection of a variety of geographically dispersed resources;
- Maintain a mix of development between Company and IPP projects for generation resources;
- Require additional transmission investments to maintain reliability and facilitate the delivery of an increasingly clean energy mix now and, in the future, particularly in the Denver metro area;
- Invest in Colorado by bringing billions in direct clean energy-related investment to Colorado, propelling economic growth and development in the process; and
- Affordably deliver the near-term clean energy transition at a rate impact of approximately 2.25%.

2.1 Introducing the Preferred Plan

The Preferred Plan consists of the bids shown in Table 1 below and the nameplate capacity by generation type shown in Table 2 below.

Table 1 – Clean Energy Preferred Plan Selected Bids

Bid ID	Project Name	Technology	Nameplate MW	Ownership Structure	In-Service
0151	[redacted]	Solar	300	PPA	2026
1125	[redacted]	Solar	115	PPA	2026
1010	[redacted]	Solar + Storage	325/200	Own	2026
1006	[redacted]	Solar + Storage	250/200	Own	2026
1029	[redacted]	Wind	500	Own	2026
1015	[redacted]	Wind	450	Own	2026
0295	[redacted]	Wind	500	PPA	2026
1000	[redacted]	Gas	400	Own	2027
0989	[redacted]	Gas	200	Own	2027
0986	[redacted]	Gas	28	Own	2027
1002	[redacted]	Solar	335	Own	2027
0218	[redacted]	Solar	355	PPA	2027
0476	[redacted]	Solar + Storage	199/100	Own	2027
0149	[redacted]	Solar + Storage	90/72	PPA	2027
0589	[redacted]	Storage	200	PPA	2027
0249	[redacted]	Storage	199	PPA	2027
0251	[redacted]	Storage	199	PPA	2027
0045	[redacted]	Wind	375	Own	2027
1012	[redacted]	Wind	302	Own	2027
1031	[redacted]	Biomass	19	Own	2028
1026	[redacted]	Wind	905	Own	2028
0044	[redacted]	Wind	375	PPA	2029

Note 1: In-Service refers to the first summer the unit is available.
Note 2: Bid 1012 and Bid 1026 would utilize the MVLE.

Table 2 - Preferred Plan Capacity by Type

Generation Type	Nameplate (MW)
Wind	3,406
Solar[5]	1,969
Storage[6]	1,170
Gas	628
Biomass	19
TOTAL	**7,192**

Clearly, the Preferred Plan includes a robust investment and transition to clean energy resources, and in so doing reduces emissions, but it also includes careful thought into how to maintain reliability and does so at a cost not only similar to the informational least cost plan but also affordably for our customer. Further, when combined with the just transition-related commitments from the approved Updated Settlement Agreement,[7] it advances a clean energy future and ensures a just transition for our workforce and communities.

We move forward with clear eyes on the challenges that lie ahead, with some of them detailed in this Report. This plan is transformational and will take careful and dedicated attention to its execution: achieving increasingly clean energy service with high reliability, affordable cost, while minimizing other adverse impacts (e.g., environmental and cultural), requires a delicate balance. Xcel Energy is uniquely situated to take on this challenge and opportunity by building on our existing national leadership in this space, having brought generation investment online at cost and on-time and engaged in nation-leading forecasting work with national research laboratories. Substantial development and operational work lie ahead to put steel in the ground and make the very physics of our system work with an energy system undergoing change.

[5] Includes capacity from both stand-alone solar and the solar portion of solar plus storage resources.
[6] Includes capacity from both stand-alone storage and the storage portion of solar plus storage resources.
[7] Updated Non-Unanimous Partial Settlement Agreement ("Updated Settlement Agreement") filed on April 26, 2022 on behalf of Public Service, Trial Staff ("Staff") of the Colorado Public Utilities Commission ("Commission"), the Colorado Office of the Utility Consumer Advocate ("UCA"), the Colorado Energy Office ("CEO"), the City and County of Denver ("Denver"), the Board of County Commissioners of Pueblo County ("Pueblo County"), the City of Pueblo and the Board of Water Works of Pueblo, Colorado ("PBWW"), the Colorado Independent Energy Association ("CIEA"), the Colorado Office of Just Transition ("OJT"), Holy Cross Electric Association, Inc. ("Holy Cross"), the Colorado Oil & Gas Association ("COGA"), the Colorado Solar and Storage Association and Solar Energy Industries Association (collectively, "COSSA/SEIA"), the International Brotherhood of Electrical Workers, Colorado Independent Energy Association ("CIEA"), Interwest Energy Alliance ("Interwest"), Local No. 111 ("IBEW"), Onward Energy Management, LLC ("Onward"), the Rocky Mountain Environmental Labor Coalition and Colorado Building and Construction Trades Council, AFL-CIO (collectively, "RMELC/CBCTC"), Sierra Club and the National Resources Defense Council (collectively the "Conservation Coalition"), Walmart Inc. ("Walmart"), and Western Resource Advocates ("WRA"), and approved, in part, by the Phase I Decision.

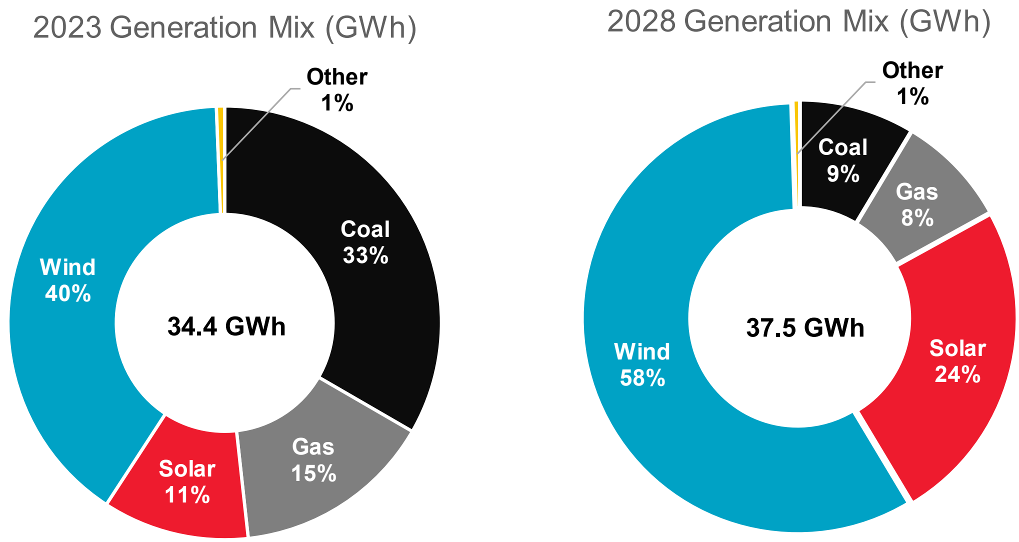
The Preferred Plan is a large plan—the largest portfolio ever advanced through the ERP process. But it provides an extensive suite of benefits to Colorado and, when compared to the “business as usual” ERP portfolio, provides greater levels of clean energy and emissions reductions with modest bill impacts. When evaluated within the statutory parameters included by the General Assembly in Senate Bill 19-236, the Preferred Plan is in the public interest.

In the following sections, we step through various areas of interest of this Commission and our stakeholders that have been the focus of attention through our Phase I proceeding as well as past ERP conversations.

2.2 The Preferred Plan is Clean

The Preferred Plan selects a number of clean energy resources to replace the retirement of over 1,800 MW of dispatchable capacity and does it in a way that capitalizes on the new financial federal support for renewable generation for the benefit of our customers. This enables the Preferred Plan to continue our nation-leading transition in the generation mix of the Public Service system from carbon-emitting resources towards clean energy. As shown in Figure 1, by 2028 the system is expected to generate approximately 83% of its electricity from clean energy in the form of wind, solar and carbon-neutral biomass. The Preferred Plan takes advantage of the abundant wind and solar available in Colorado, which can be delivered to serve our customers via the forward-looking CPP, May Valley-Longhorn Extension (“MVLE”), and the follow-on transmission upgrades in the Denver metro area. And the benefits stretch beyond the energy mix; indeed, as explained later in this Report, the Preferred Plan is projected to provide $2.5 billion in tax benefits to Colorado communities.

Figure 1 – Modeled Energy Mix Current vs. Preferred Plan



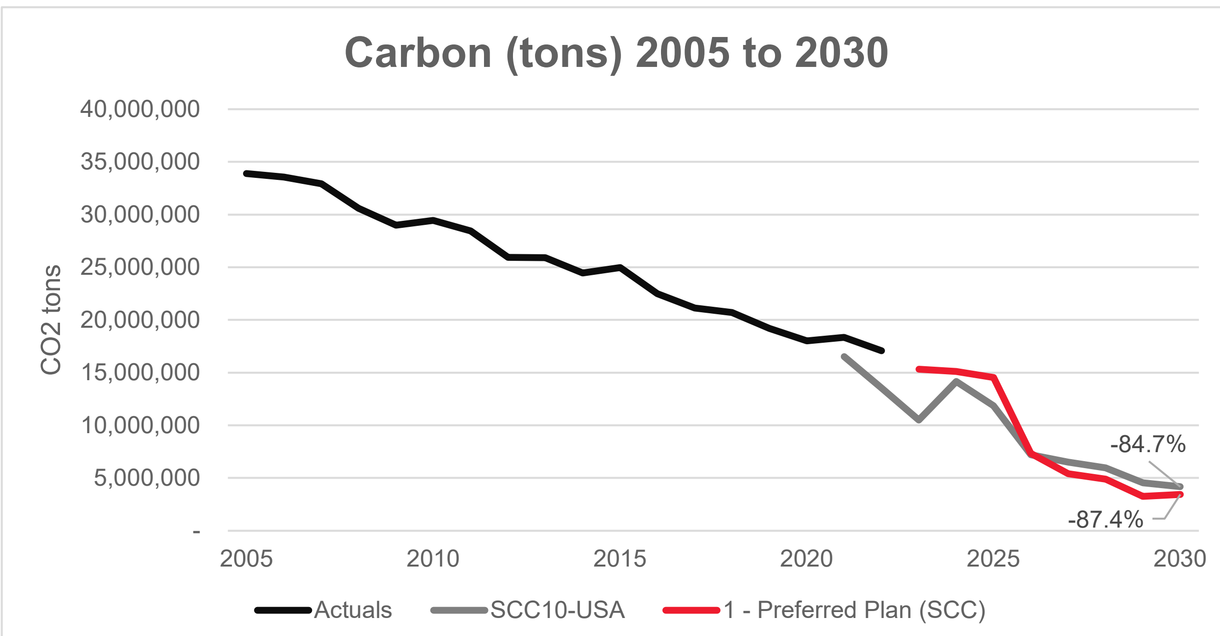
Accompanying the incremental addition of renewable energy is a significant addition of storage resources. Storage enables more clean energy resources, reduces the volume of necessary dispatchable resources and enhances the reliability of the system—to a point. The Company has recently brought 225 MW of utility-scale storage online in addition to the existing 340 MW Cabin Creek pumped hydro storage facility, and in the Preferred Plan is recommending a swift expansion of storage on the Public Service system. In turn, the availability and acquisition of cost-competitive utility-scale storage is reducing, but not eliminating, the need for new carbon-emitting capacity resources—namely in inclement weather and during long duration high load situations.

The Preferred Plan demonstrates a reduction in carbon and other emissions, with modeling results well exceeding the objective of 80% carbon emissions reductions from 2005 levels by 2030. However, it is important to note that these are modeled results seven years into the future and, in addition to all of the normal variance in forecasting, the modeling process itself leads to structural optimism in emissions reduction potential. As discussed in Section 3.8 regarding the Commercial Operations analysis of the modeling, real time operations will likely have less optimistic results than those predicted by the models. While the operators, and the systems they use, make the best decisions based on the information available at the time, actual results will differ from the modeled results presented here.

The Company's generation mix after implementation of the Preferred Plan positions the Company to do its part, and very likely more, in reducing emissions statewide to the ultimate benefit of the statewide emission reduction goals in 2030 and beyond. Accordingly, this Preferred Plan complies with the provisions of Senate Bill 19-236 and satisfies the public interest criteria for a Clean Energy Plan, as explained later in this Section. It also positions the Company to submit a verification workbook to the Colorado Department of Public Health and Environment ("CDPHE") for the Preferred Plan with the expectation that the portfolio meets the regulatory guidelines for electric sector carbon reduction targets set forth in § 25-7-105I(VIII)I, C.R.S.

To be clear, the Company is confident that the Preferred Plan, if fully executed, will be operated in a manner that achieves at least the 80% carbon reduction in 2030. However, it is unrealistic to expect that the actual results for 2030 will be the same as the 87.4% carbon emissions reduction shown by the model. While it is impossible to determine a hard "handicap" for the model results, the Company believes we would likely achieve an 80%-85% reduction. Figure 2 below reflects both the actual carbon reductions achieved in our efforts since 2005 and the modeled carbon trajectory for the Public Service system as a result of the Preferred Plan.

Figure 2 – Carbon Trajectory of Public Service System[8]



2.3 The Preferred Plan is Reliable

Several different views support the conclusion that the Preferred Plan is reliable. This starts with the Loads and Resources Table ("L&R Table"), is buttressed by the technological and geographic diversity of the Preferred Plan and is further informed by

[8] "SCC 10-USA" represents the Phase I generic plan from the Updated Settlement Agreement ("USA").

extensive reliability testing of the portfolios presented in this Report. The takeaway is that the Preferred Plan is the most reliable plan presented here.

Load and Resources Table

The Preferred Plan satisfies the Company's modeled capacity needs over the resource acquisition period ("RAP") (i.e., through the end of 2028)[9] as shown below. The Preferred Plan solves for capacity needs and emissions reductions at the same time. The influence of the social cost of carbon ("SCC") in modeling drives more weather-dependent generation and storage in lieu of carbon-emitting resources, which creates a larger plan overall on a nameplate basis but also a plan that meets reliability needs and reduces emissions. The L&R Table showing the net capacity position with the Preferred Plan, relative to the required reserve margin, is shown below in Table 3. The remaining capacity needs for 2029 and 2030 will be met by the Pueblo Just Transition Plan solicitation. Given the net capacity positions from now through 2028, it is extremely important that selected projects meet their in-service dates and allow for the delivery of the Preferred Plan.

Table 3 - Load and Resources Table, Preferred Plan 2023-2030[10]

PSCo L&R Table (MW) for Summer Peak	2024	2025	2026	2027	2028	2029	2030	
Existing Resources	7,911	7,948	7,323	6,764	6,109	5,943	5,960	
Preferred Plan Resources	-	-	352	1,354	1,621	1,649	1,626	
TOTAL ACCREDITED CAPACITY	**7,911**	**7,948**	**7,675**	**8,118**	**7,730**	**7,592**	**7,586**	A
Native Load Forecast	7,157	7,224	6,960	7,037	7,136	7,247	7,374	
Demand Response	(593)	(618)	(652)	(631)	(679)	(725)	(767)	
FIRM OBLIGATION LOAD	**6,564**	**6,606**	**6,308**	**6,406**	**6,457**	**6,522**	**6,607**	B
Target Planning Reserve Margin %	*19.2%*	*19.2%*	*19.1%*	*18.0%*	*18.0%*	*18.0%*	*18.0%*	
Target Planning Reserve Margin	1,260	1,268	1,205	1,153	1,162	1,174	1,189	
IREA & HCEA Backup Reserves	48	48	11	11	11	11	11	
TOTAL PLANNING RESERVE MARGIN TARGET	**1,308**	**1,316**	**1,216**	**1,164**	**1,173**	**1,185**	**1,200**	C
CAPACITY NEED	7,873	7,923	7,524	7,570	7,630	7,707	7,807	B + C
ACTUAL RESERVE MARGIN	1,347	1,342	1,367	1,712	1,273	1,070	979	A - B
Actual Reserve Margin %	*20.5%*	*20.3%*	*21.7%*	*26.7%*	*19.7%*			
CAPACITY POSITION: LONG/(SHORT)	**39**	**26**	**151**	**548**	**100**	**(115)**	**(221)**	A - B - C

[9] The Phase I Decision establishes a single RAP from 2021 through 2030; however, the Company agreed not to accept bids for and not to acquire resources with in-service dates after December 31, 2028.
[10] Existing resources, load forecasts, and DR forecasts are consistent with the Loads and Resources Table as filed in the Supplemental Direct Testimony of Jack W. Ihle filed in Proceeding No. 23A-0046E.

As more fully discussed in Section 3.5, the base EnCompass[11] output for the firm capacity position of a portfolio does not fully capture capacity value resulting from the interplay between various technologies (wind, solar, storage) or the cumulative impact of adding storage of various durations (2-hour and 4-hour combined impacts). Thus, to accurately determine the firm capacity of a resulting portfolio, the final solved portfolio is run through the Plexos[12] loss of load probability ("LOLP") subroutine to calculate the portfolio's total contribution to resource adequacy, as defined by the planning reserve margin ("PRM") study. This portfolio capacity calculation, plus the existing resources on the Company's system leads to the forecasted capacity position shown in the L&R Table.

Ideally, in addition to determining a portfolio's overall accredited firm capacity, an allocation of the firm capacity to each bid would be conducted, essentially determining the effective load carrying capability ("ELCC") for each bid. Due to the time intensive nature of this process, there was not the opportunity to develop bid-level ELCC information for this Report. Further refinement of the ELCC attributable to bids and technology types will be conducted in the full ELCC and PRM studies completed early next year for inclusion in the Pueblo Just Transition Plan filing that will be submitted no later than June 1, 2024.[13]

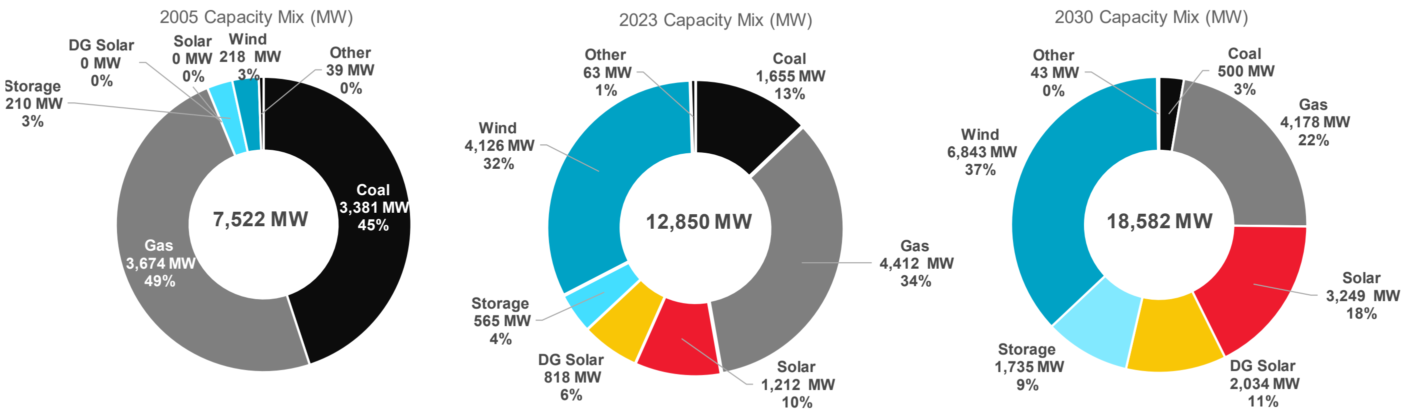
Technology and Geographic Diversity

The Preferred Plan includes a broad mix of proven clean energy technologies to continue the successful progress Colorado has made towards reducing emissions from electricity generation, while keeping customer costs low. The 2016 ERP resulted in the Colorado Energy Plan, which continued the transition that began with the Clean Air-Clean Jobs Act in 2010 of changing from a primarily coal-based electric system to a broad mix of clean energy technologies. The Preferred Plan continues the transition from coal to clean energy while utilizing support from federal tax incentives to reduce customers' costs. It is important to recognize that under Senate Bill 19-236, the objective is to reduce emissions without compromising reliability. The Preferred Plan achieves this objective through the use of a diverse set of technologies. Indeed, upon approval of the Preferred Plan, the Public Service electric system will have a mix of

[11] EnCompass is the industry-standard capacity expansion planning and production costing model used by the Company and developed by Anchor Power Solutions.
[12] Plexos is a production costing model similar to EnCompass that is primarily used by the Company for shorter term fuel cost forecasting. It also has a LOLP calculation feature that is currently not available in EnCompass. Plexos is developed by Energy Exemplar.
[13] The Company notes that, while the Preferred Plan solves for resource adequacy throughout the RAP from a Load and Resources perspective, we remain vigilant on short-term resource adequacy issues. The need for all chosen projects to be delivered on time is critical, and risks to that large of a portfolio achieving all expected milestones are real.

clean energy technologies anticipated to deliver reliable energy to our customers, including during periods of adverse weather. A comparison of the past (2005), current (2023), and future (2030) systemwide mix of technology is shown below in Figure 3 and shows the dramatic transformation of the Public Service system to a diverse mix of modern clean technologies.

Figure 3 – Systemwide Technology Mix Changes Over Time



In addition, the Preferred Plan spreads this technology over a broad geographic area of the State, relying on the vision of the forward-looking CPP transmission project—thereby reducing the likelihood of low wind or cloud cover affecting many of the new resource additions simultaneously. Two graphics of the Preferred Plan bid locations are presented below in Figure 4 and Figure 5 that show the wide geographic diversity and utilization of the CPP.

The Company notes that, while the Preferred Plan has a very good representation of geographic diversity in new resources, integration of these high amounts of renewable energy into our system poses an ever-increasing challenge in operations and planning. Geographic diversity is one tool to help mitigate this challenge, but nonetheless, the large quantity of renewables added in the Preferred Plan, combined with the large proportion of renewable energy on our system now, will make this a topic of focus for years to come.

Figure 4 – Preferred Plan Bid Locations – Geographic Diversity

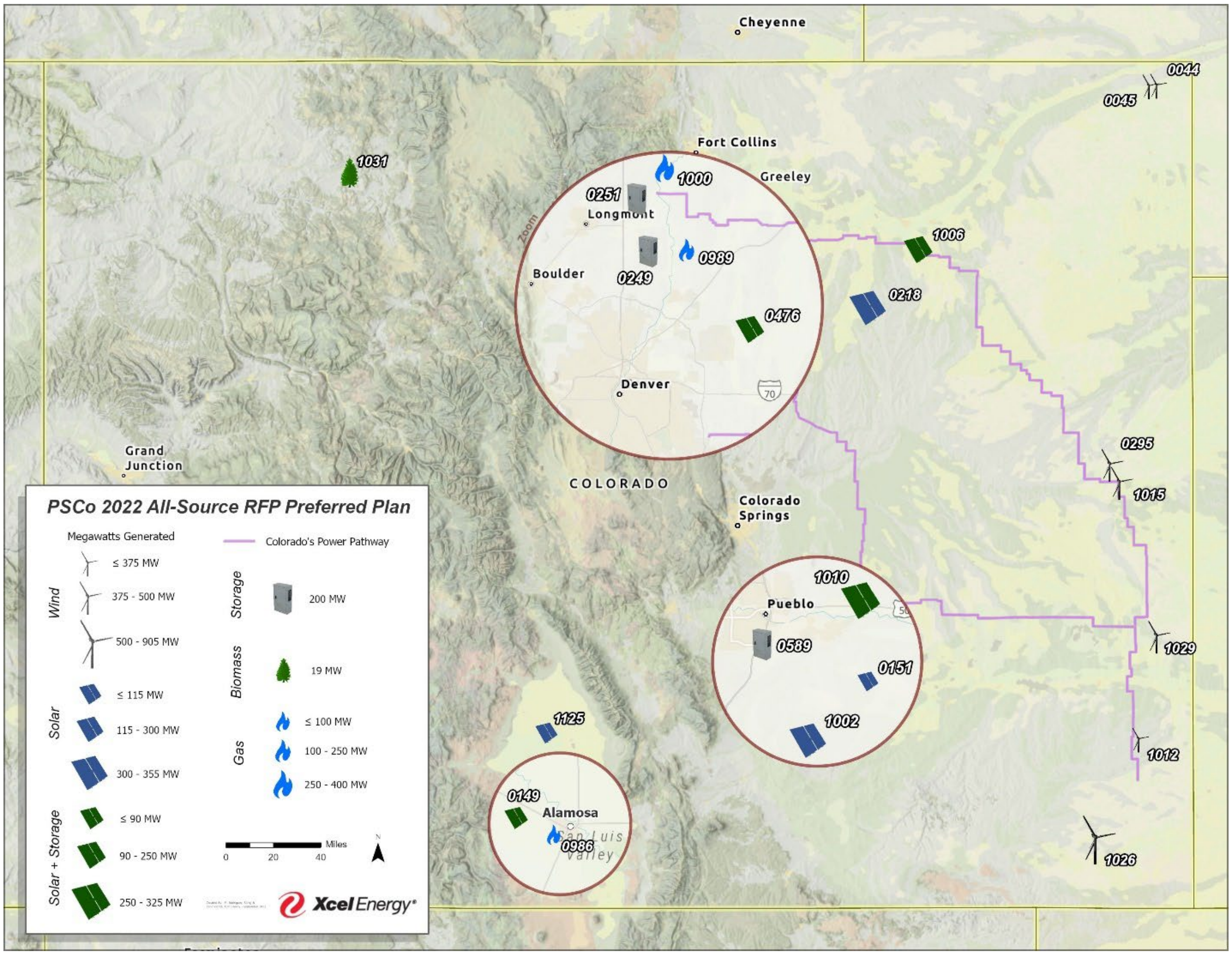
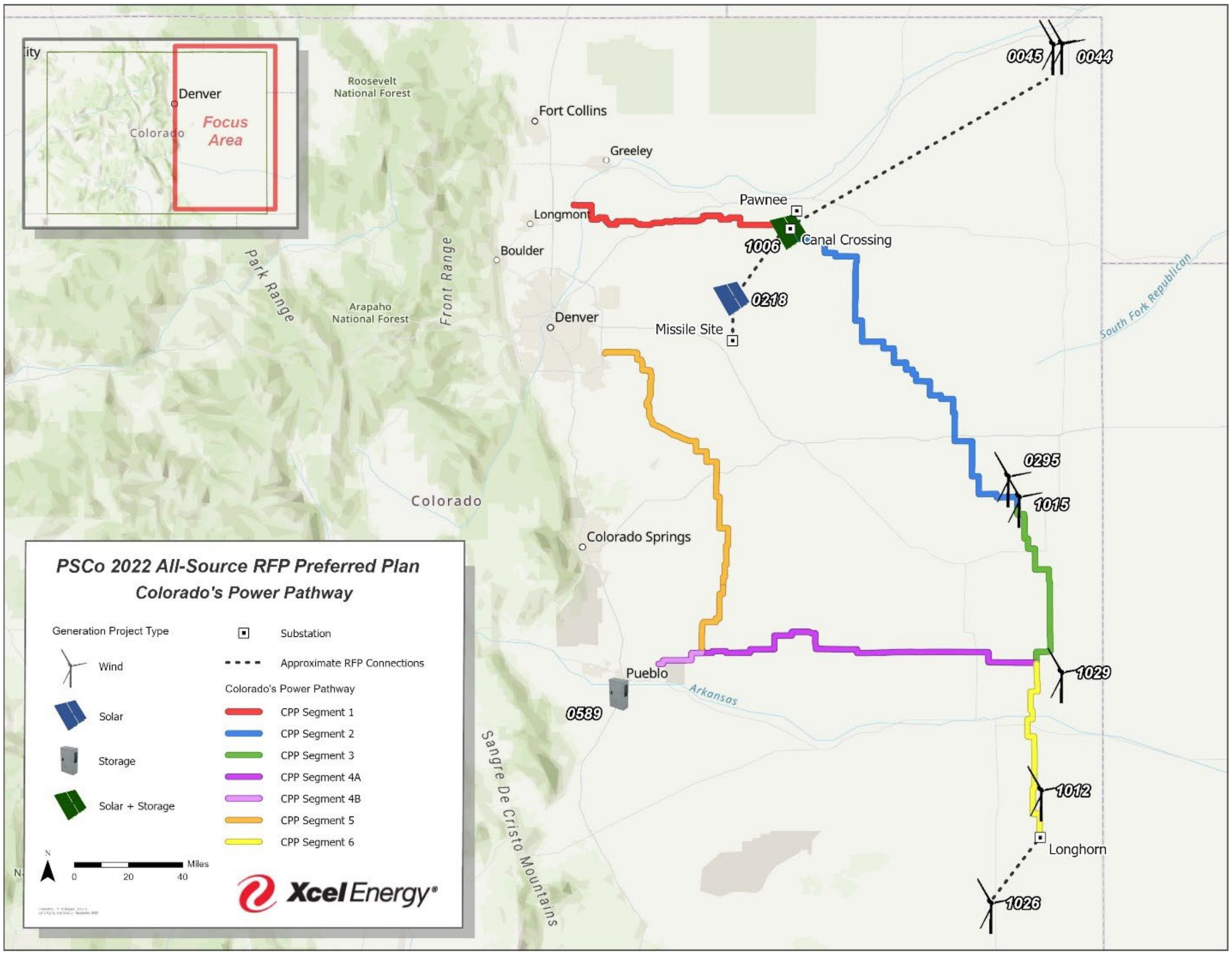


Figure 5 – Preferred Plan Bids Utilizing Colorado's Power Pathway (CPP)



The Preferred Plan Satisfies Reliability Testing

Reliable delivery of electricity is always at the forefront of any action taken by the Company. The codified legislative declaration for Senate Bill 19-236 also recognizes the importance of this as one of the stated goals articulated by the General Assembly to "allow Coloradans to enjoy the benefits of *reliable* clean energy at an affordable cost."[14] Customers rightfully expect safe and reliable service; accordingly, the Company prioritizes reliability, and the development of the Preferred Plan as a reliable plan has been paramount. We appreciate that the Commission understands this solemn responsibility of reliability in planning as well.

[14] § 40-2-125.5(1)(e), C.R.S. (emphasis added).

Section 3 describes the modeling and analysis conducted to ensure the plans are reliable in more detail. At a high level, the Company utilized the processes and tools that were laid out in Phase I of this proceeding to ensure that the portfolios developed met core reliability criteria of:

- Achieving reliable operations outcomes after the application of reliability tests designed to ensure that the energy and ancillary services needs approved in Phase I and set forth in the Company's retail and Federal Energy Regulatory Commission ("FERC") tariffs are met, even during outlier weather events.
- Meeting the Planning Reserve Margin criteria adopted by the Phase I Decision.
- Evaluating deliverability to the geographic load centers using the existing and planned transmission system.

<u>Reliability Testing</u>

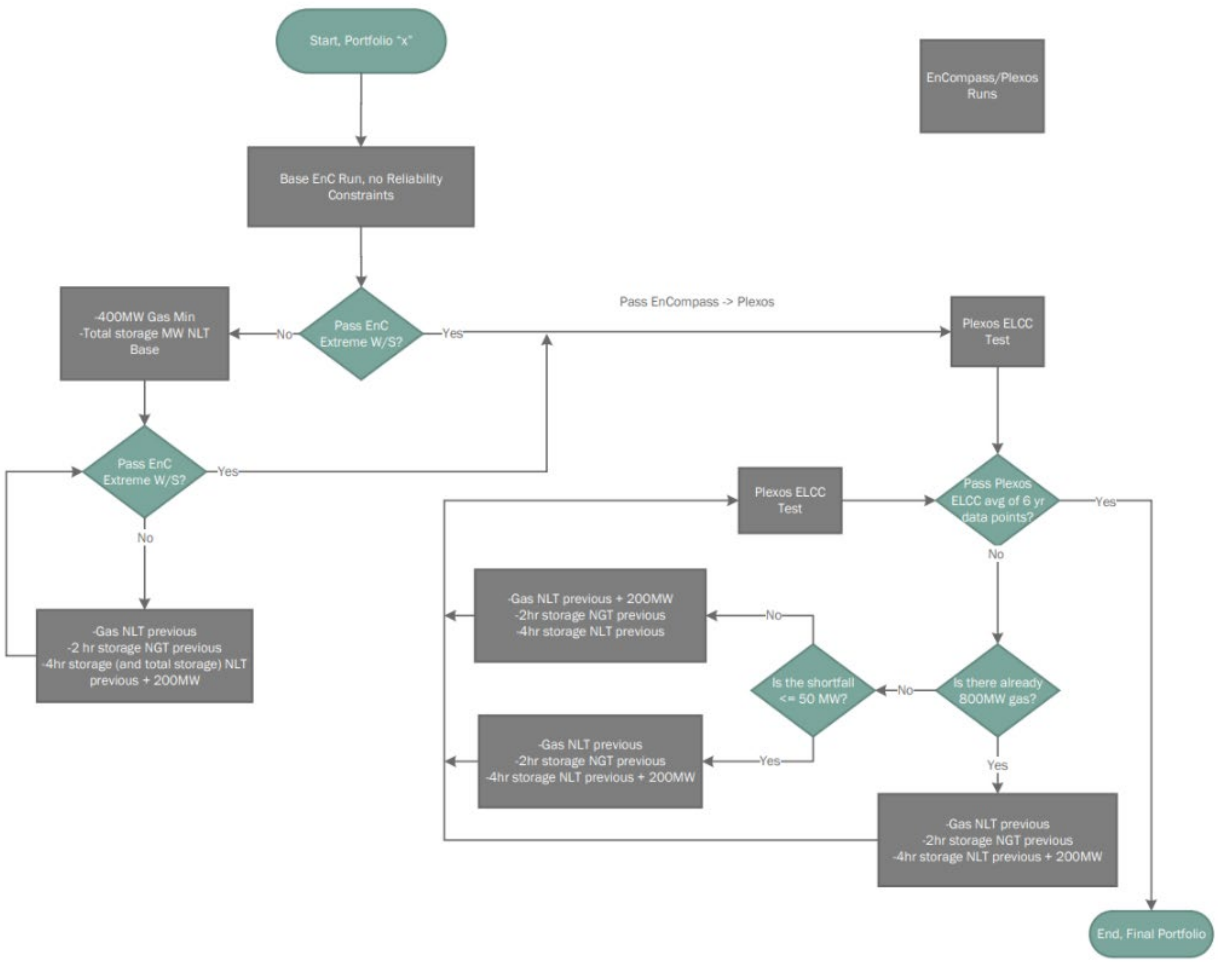
The primary means of satisfying the criteria of meeting our energy, ancillary service and the PRM needs were by using the EnCompass and Plexos modeling tools under a variety of conditions. Once a baseline model run is completed successfully, the baseline is then "tested" against various system conditions (e.g., extreme weather) to validate the solution is reliable under various conditions.

As discussed further in Section 3, the initial "raw output" portfolios from the EnCompass model did not meet either the first or second criteria bullets (i.e., reliability testing or meeting the PRM). More specifically, these raw output portfolios did not result in a firm capacity that met the PRM criteria, nor did they meet the energy and ancillary service needs of the system under hot and cold weather conditions based on recent historical events.[15]

To ensure the portfolios being developed were reliable and able to be compared on a similar basis, an unbiased "reliability rubric" or "rubric" was created with the IE for purposes of testing the reliability of each portfolio.[16] This rubric was created to formalize the process of developing reliable portfolios using the tools available to the Company, specifically both EnCompass and Plexos. This rubric is shown below as Figure 6, and also included as Appendix E for clarity.

[15] The Company tested the portfolios in EnCompass to ensure energy and ancillary services were met under a cold February scenario based on the load and renewable production during Winter Storm Uri in 2021, and a hot July based on load and renewable production during a hot week observed in July 2022. Additionally, the Company tested performance, but did not require 100% passing, under the extreme summer scenario analyzed in the Company's Supplemental Direct Testimony and as originally conceived by the Commissioners during oral deliberations on May 19, 2021.
[16] The rubric is considered unbiased because it is applied to all portfolios consistently and does not prejudice the model as to which bid or ownership type is selected.

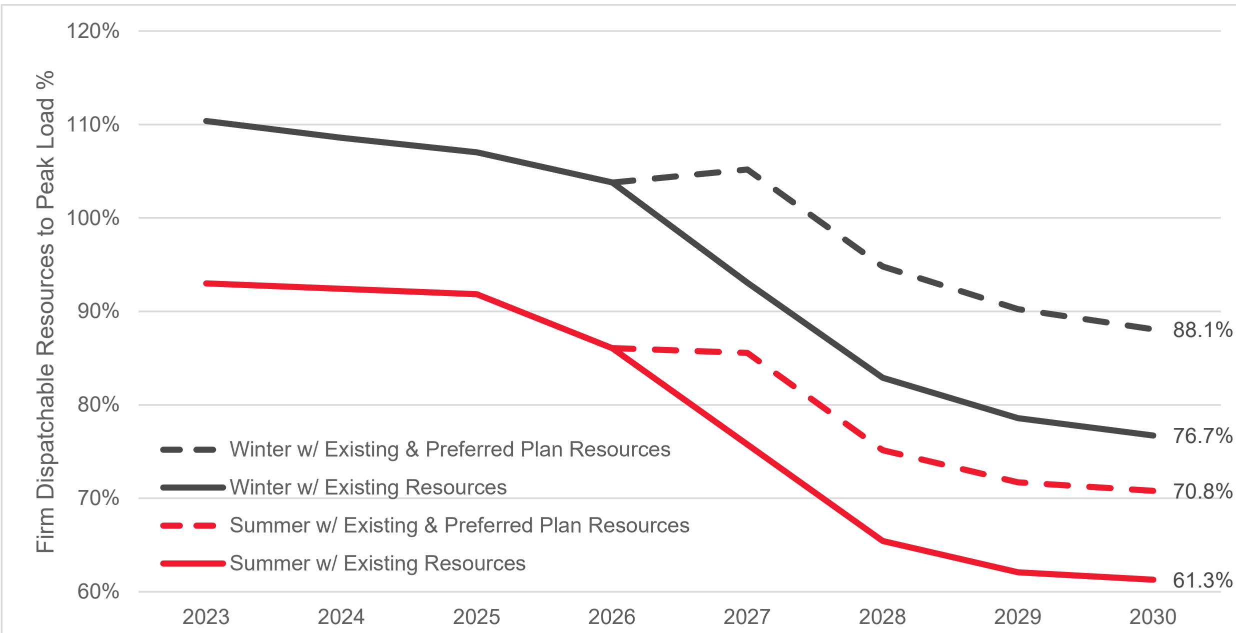
Figure 6 – Reliability Rubric



The Preferred Plan passed the reliability testing set forth above. Additionally, each portfolio presented in this Report satisfied this reliability testing. That is not, however, the end of the inquiry.

As explained in more detail in this Section (specifically Section 2.4 and Section 2.7), strategically located dispatchable generation makes the Preferred Plan a more reliable portfolio than other portfolios put through the reliability testing. The Company's Preferred Plan includes a modest amount of new, strategically located, and highly flexible natural gas combustion turbines ("CTs") at existing brownfield sites to enable the integration of the unprecedented levels of variable generation this plan envisions. These resources are sized and located to provide maximum benefit to the system and in the amount needed to reliably operate the system—and no more. These units are essential to operating the system and a key "insurance policy" for our customers. To determine the optimum level needed in this ERP, the Company employed a variety of analytical approaches and modeling to reach this recommendation. It is key to understand that the Public Service system will evolve dramatically over the next several years as we transition away from coal and older inefficient units at the end of their useful lives. Indeed, the Company is rising to the challenge of managing a system with a much higher reliance on weather-dependent generation and supporting storage to deliver the real-time energy our customers expect, and it will be a challenge as well as we will learn things every day. Figure 7 below shows the trajectory of the system in terms of the amount of thermal generation as a percentage of peak load. Even with the addition of these new firm dispatchable resources, we will proceed with lower amounts of thermal resources (dispatchable gas and coal primarily) than ever experienced.

Figure 7 – Evolving Thermal Dispatchable Generation



This is discussed in more detail in Section 3. The key takeaway is that even with the Preferred Plan (the most reliable portfolio presented in this Report), the Company will move forward with the highest levels of weather-dependent generation and the lowest levels of thermal dispatchable generation it has ever had, while still satisfying the reliability testing conducted for purposes of portfolio development here.

Planning Reserve Margin

The Preferred Plan also satisfies the Company's capacity needs, inclusive of the PRM, in each year of the RAP (i.e., through the end of 2028). The Phase I Decision found "that Astrape's planning reserve margin study and the associated proposed increase in the planning reserve margin to 18 percent are appropriate for this Proceeding. Given the resource adequacy concerns across the West and the lack of credible alternatives presented in this Proceeding, the Company's proposed 18 percent reserve margin is consistent with current practice and is reasonable."[17] The expected PRM resulting from the Preferred Plan for the years studied is shown in Table 4 below. The PRM target for the intervening years is carried forward from the study year.

Table 4 - Planning Reserve Margin (2021-2030)

Year	**2021**	**2023**	**2026**	**2030**
Reserve Margin	17.4%	19.3%	19.1%	18.0%

Evaluating Deliverability to Load Centers

Earlier stages of clean energy-driven transmission investment were primarily focused on connecting remotely located wind and solar generation to load centers, and the Company's analysis shows that a new phase of the transition is emerging – reliably managing power transmission within and around the metropolitan area. Delivery of remote resources is still an important consideration of transmission planning, as evidenced by the critical role that the CPP plays in enabling the Preferred Plan. However, as the Company moves towards a grid powered primarily by renewable resources, and less reliant on legacy urban power plants, transmission investments are increasingly focused on enhancing the capacity and resilience of the entire transmission grid—including those parts of the grid located closest to our customers' homes and businesses.

As a result of existing resource retirements, the bids available to the Company to select in our portfolios, and evaluating deliverability to load centers, substantial additional transmission investment is required to deliver the resources that interconnect to the CPP, MVLE, and elsewhere on the Company's transmission system to the Denver metro area. To evaluate and ensure the deliverability of these resources, the Company developed an analysis of transmission investment needed to bring the energy produced by these resources to customers. The current estimate for these investments is $2.574 billion, with additional investment required to address San Luis Valley system issues and for the MVLE. The Company previously noted that Denver metro upgrades would depend on the nature of the portfolios presented in the Phase II process. The loss of certain IPP resources previously contracted to the Company under PPAs to new off-takers, and the lack of bids for resources that exist within the Denver metro constraint, have driven the investment need for the Denver metro higher. The cost estimates are reflected in Table 5 below.

[17] Phase I Decision, at ¶ 199.

Table 5 - Transmission Investments (in Millions)[18]

Transmission Cost Category	Estimated Cost ($M)
Denver Metro Transmission Network Upgrades	$2,146
San Luis Valley Transmission Network Upgrades	$176
May Valley – Longhorn Extension (MVLE)	$252
Total	$2,574

The process here does not allow for a full vetting of the transmission investments triggered by the portfolios, and this represents the Company's best estimate at this time. Even the "business as usual" ERP portfolio without the SCC, a smaller portfolio from a resource perspective, requires the vast majority of these investments (specifically the Denver metro investments) to ensure deliverability.

Inclusive of these transmission investments, the Preferred Plan meets this requirement of the reliability assessment.

<u>The Preferred Plan's Reliability</u>

The Preferred Plan satisfies each of the criteria set forth above, and in fact is stronger from a reliability perspective than other portfolios presented in this Report. The reason for this is simple. While other portfolios satisfy the reliability rubric, meet the PRM, and have met deliverability requirements, this evaluation standing alone does not meet local reliability needs. The Preferred Plan does. Its use of strategically located dispatchable generation meets key needs both in the San Luis Valley and in the Denver metro area. The Preferred Plan is therefore the plan the Company is most comfortable presenting, while also meeting state emissions reduction policy and just transition objectives.

2.4 The Preferred Plan is Affordable

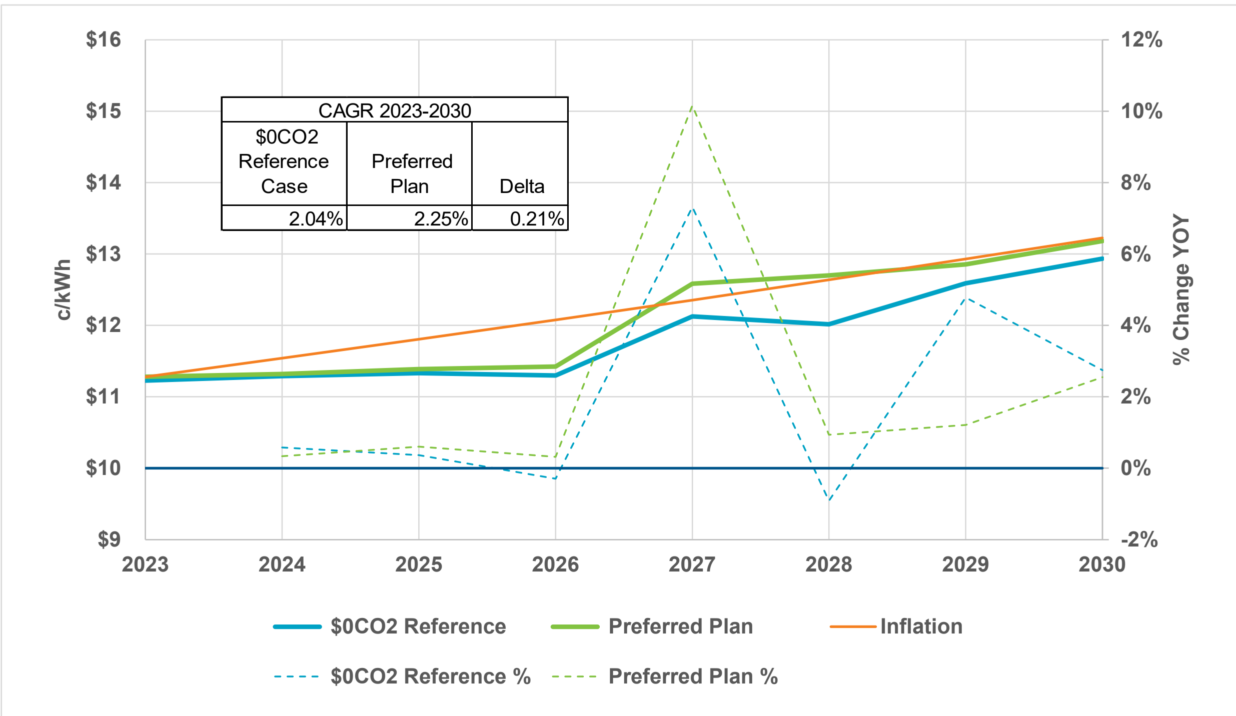
Driven in part by the benefits from the IRA, the Preferred Plan is projected to deliver reliable, clean energy to our customers while maintaining affordability. In fact, inclusive of the estimated transmission investment, the average bill impact for the Preferred Plan is expected to grow less than the historical rate of inflation.

Isolating the impacts of the actions proposed in this ERP, including both the Preferred Plan and estimated transmission investment, total system average rates are expected

[18] For a discussion of total costs associated with the implementation of portfolios, including the Preferred Plan, please see Section 6 of this Report and Table 35.

to rise at approximately 2.25% annually, compared to the most recent estimate of inflation over the same period of 2.3%.[19] It is also important to note that much of the cost increase is not driven by the specific actions of the Preferred Plan; rather, these costs would be incurred regardless of the path chosen. More specifically, this ERP will need to fill the 2028 capacity need of 1,521 MW of accredited capacity, and much of the identified transmission system improvements would be required for any portfolio that meets this need. Indeed, the ERP "business as usual," or Reference Case Plan (without the SCC) best represents a minimum action scenario, and the cumulative average growth rates ("CAGRs") under this scenario are projected to increase by 2.04%, only 0.21% less than the Preferred Plan. The forecasted average system rates and year-over-year ("YOY") changes for the Reference Case and Preferred Plan are shown below in Figure 8.

Figure 8 – Total System Rates, Preferred Plan and Reference Case



Additionally, the total system revenue requirements for the Preferred Plan and the Reference Case are similar. The Reference Case has a projected 2030 revenue requirement of $4.38 billion and the Preferred Plan has a 2030 revenue requirement of $4.46 billion, with a difference of $83.5 million, or 1.9%.

[19] Based on a forecast of Gross Domestic Product, 2023-2030 provided by the Company's external econometrics vendor.

When compared with the "business as usual" path, the Preferred Plan has slightly higher costs but substantially more benefits. In addition, standing on its own, the Preferred Plan total system average rates remain less than inflation. Both of these views reinforce the conclusion that the Preferred Plan is affordable.

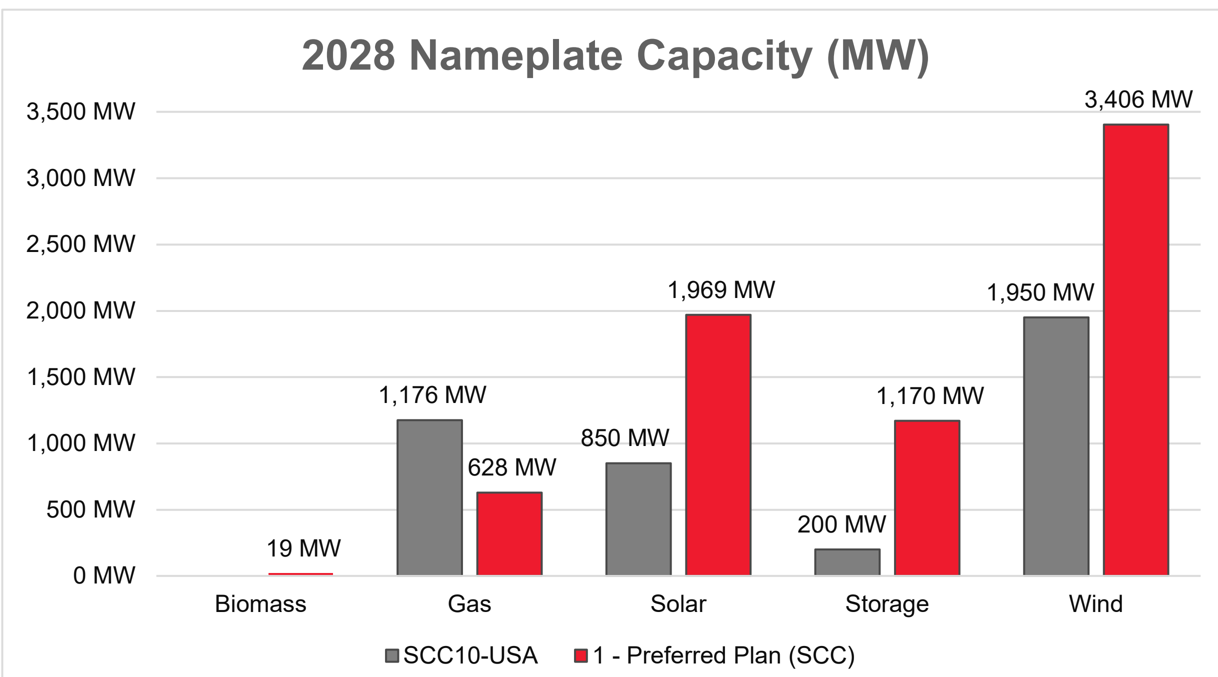
2.5 The Preferred Plan is Competitive Now and for the Future

Comparisons of the Preferred Plan to other portfolios, robust IPP participation in the plan to ensure a continued and strong Colorado energy market, and an extensive set of backup bids make the Preferred Plan competitive today and going forward.

The Preferred Plan Beats Expectations

Overall, the proposed Preferred Plan increases the clean energy resources and reduces the carbon-emitting resources as compared to the indicative modeled results during Phase I, as shown in the comparison below between the generic plan from the Updated Settlement Agreement (SCC10-USA) and the Preferred Plan. The Preferred Plan has about half as much carbon-emitting generation and almost twice as much renewable generation as originally modeled using the generic resources in Phase I. The Plan also takes advantage of the IRA tax benefits for storage, adding almost six times as much storage as contemplated in Phase I, using the storage to effectively utilize otherwise curtailed renewable energy, provide critical ancillary services, and meet peak demand in the evenings when solar generation declines.

Figure 9 – Comparison to Phase I



The Preferred Plan is Strategic

Historically, one of the primary comparisons in 120-Day report has been the Preferred Plan to the informational least cost plan ("LCP"). The informational LCP is developed without constraints such as renewable portfolio goals or ownership levels, nor does it have resources selected based on other criteria (e.g., local reliability needs or just transition considerations). For these reasons, and because Colorado does not do least-cost electric resource planning as a policy matter, least cost plans serve as an informational benchmark for comparison. Table 6 below presents the comparison between the informational LCP and the Preferred Plan.

Table 6 – Preferred Plan Comparison to Least Cost Plan

Portfolios' Comparison of Key Characteristics

	1 - Preferred Plan (SCC)	3 - Least Cost Plan (SCC)
Nameplate Capacity (MW)		
Biomass	19	-
Gas	628	619
Solar	1,969	2,369
Storage	1,170	1,420
Wind	3,406	3,406
TOTAL Nameplate Additions (MW)	7,192	7,814
Flexible Capacity (MW)	1,817	2,039
Colorado Power Pathway (CPP) Trx Utilization (MW)	4,411	4,861
CPP May Valley-Longhorn Extension Trx Utilization (MW)	1,206	1,206
Accredited Capacity (MW)	1,621	1,673
Section 123 Capacity (MW)	19	-
Owned Capacity (MW)	4,787	4,540
Owned Capacity (%)	66.6%	58.1%
Owned Energy (%)	69.7%	65.7%
Accredited Capacity Position		
2028 Capacity Position Long/(Short) (MW)	100	152
2028 Actual Reserve Margin (%)	19.7%	20.5%
Planning Period Present Value Revenue Requirement (PVRR) ($M)		
NPV Base Portfolio Costs ($M)	$ 41,708	$ 41,497
NPV Trx PO-PF Interconnection Costs ($M)	$ 130	$ 135
NPV Trx Network Upgrades for Delivery ($M)	$ 2,353	$ 2,353
TOTAL PVRR ($M)	$ 44,191	$ 43,984
PVRR Delta vs. Preferred Plan ($M)	$ -	$ (207)
Emissions		
2023-2030 CO2 (M Tons)	69,322,272	68,822,125
2023-2055 CO2 (M Tons)	93,063,889	90,731,893
2023-2055 CO2 Delta vs. Preferred Plan (M Tons)	-	(2,331,996)
2030 CO2 Reduction from 2005 (%)	-87.4%	-88.1%
2023-2055 NPV CO2 at SCC ($M)	$ 6,288	$ 6,160
2023-2055 NPV Methane at SCM ($M)	$ 57	$ 54
TOTAL Present Value Societal Cost (PVSC) ($M)	$ 50,535	$ 50,197
PVSC Delta vs. Preferred Plan ($M)	$ -	$ (338)
Other		
2023-2055 Natural Gas Burn (MMBtu)	648,263,108	611,327,790
2028 Renewable Energy MWh (%)	83.0%	83.7%

The primary differences between the two portfolios are reduced to three factors: (1) Alamosa Reliability; (2) Transmission Support; and (3) Hayden Just Transition.

- Alamosa Reliability – As explained in more detail in Section 5.1, the retirement of the existing Company-owned Alamosa CT at the end of 2026 will leave no firm dispatchable resources located in the San Luis Valley. The Company believes it is essential from a reliability perspective to continue to have firm dispatchable generation in the region. To ensure this result, the Company added a modeling parameter to require at least one of the three submitted bids for firm dispatchable generation in the Alamosa area to be selected in the Preferred Plan. The optimized model results selected Bid 0986, a 28 MW aero-derivative gas-fired CT with fuel oil as a secondary backup fuel. This alternative provides reliable generation to serve the San Luis Valley load at all hours in the event of transmission and/or natural gas supply issues.[20]

- Transmission Support – A significant part of the transmission plan for this planning cycle consists of resolving the existing import capability limitations into the Denver metro area load center, as discussed in Section 6.0 and Appendix Q. In addition to the proposed transmission solutions to alleviate capacity limitations, having generation sources located on the opposite side of the limiting constraint provides beneficial counter flow to mitigate transmission congestion and thus increase import capability. This can enable more renewable generation to be utilized on the system (i.e., not curtailed), facilitates reliable transmission system real-time operations, and assists with maintaining system reliability during times when the transmission constraint might be binding due to high load levels and/or facility outages on the transmission system. Bid 0989 is the only bid submitted that includes firm dispatchable generation providing supportive benefit to the transmission constraint. As the existing units at that site are scheduled for retirement at the end of 2026, reutilizing this advantageous site for brownfield development of replacement generation makes both economic and operational sense.

- Hayden Just Transition – The Hayden Biomass project (Bid 1031)[21] demonstrates the Company's commitment to providing a just transition during the evolution of our generation portfolio by supporting the local community and displaced workforce from the retiring Hayden coal units in the Yampa Valley. The Hayden Biomass project is

[20] There is significant installed and planned solar generation in the San Luis Valley that helps with daytime reliability but is not effective in non-daylight hours.
[21] The Company notes that it has intentionally presented the Hayden Biomass project name and project details as public information.

the only Section 123 bid recommended for inclusion in the Preferred Plan, and the project will yield benefits to the system and further the development of carbon free/neutral dispatchable resources for meeting future, and deeper, emissions reductions. The biomass unit will utilize primarily forest waste resulting from fire prevention activities and residual debris from the recent forest pine beetle outbreak. These materials would otherwise be burned on site, resulting in carbon emissions and uncontrolled pollutants being released with no beneficial byproduct. The alternative of utilizing these materials in a state-of-the-art biomass facility with modern efficient emissions controls and providing firm dispatchable carbon-neutral electricity provides significant societal and environmental benefits. This project is anticipated to:

- Employ 26 full-time, long-term employees for operations, aiding in labor retention in the area and reducing workforce transition costs. This is in addition to the supportive employment in the fuel acquisition and delivery process and other typical plant operational support services.
- Provide enough carbon neutral generation to supply over 36,000 Colorado homes annually.
- Reduce air emissions, specifically: 95% to 99% reduction in particulate matter, carbon monoxide, and volatile organics, and a 60% to 80% reduction in nitrogen oxides when compared to open burning.
- Provide a market for byproducts from forest management activities, contributing to reduced wildfire risk, diverting land fill waste, and aiding in maintaining healthy forest ecosystems.

The changes between the Preferred Plan and the informational LCP result in slightly less solar (-400 MW) and less storage (-250 MW) in the Preferred Plan, both of which are likely attributable to: (1) the increased firm dispatchable generation from the Alamosa CT; and (2) the increased carbon-free energy from the biomass unit that are included in the Preferred Plan. Additionally, capturing these key local reliability and just transition benefits changes the present value revenue requirement ("PVRR") in 2055 from $43.984 billion to $44.191 billion (incremental cost of $207 million or a change of about 0.5%) over the informational LCP on a PVRR basis.

Also of note, in this ERP planning cycle, Company utility development has proven to be economically competitive with third-party projects. Therefore, Company-owned projects are relatively equally represented in both the Preferred Plan and the informational LCP.

The Preferred Plan Achieves Balance

The Preferred Plan features broad participation from energy market participants, with different ownership and development structures and a role for IPPs at different stages of the development cycle. The Preferred Plan, as well as all other portfolios including the informational LCP, include more balanced levels of Company-owned projects when compared to more recent ERP cycles. This is a direct result of the more equitable tax credit policy for clean energy resulting from the historic IRA. This legislation, in addition to providing enormous financial support for clean energy projects that this CEP captures, also removed financial barriers that have made regulated utility ownership of renewable projects more financially challenging in the past. These changes include:

- Allowing transferability of tax credits, thereby providing a solution to more efficiently utilize clean energy tax credits.
- Allowing the option to elect a production tax credit ("PTC") for solar projects instead of an investment tax credit ("ITC").

Prior to the IRA, utilities were not able to transfer clean energy tax credits to other parties, and typically held them on the balance sheet until the tax credits could be utilized. If the utility could not use the credits in the year they were generated, a tax credit deferred tax asset ("DTA") was established until the credit could be utilized. This tax inefficiency resulted in higher costs to customers. Now utilities can effectively sell credits to other parties (within the rules established by the Internal Revenue Service ("IRS")) resulting in more efficient monetization of tax credits and eliminates the tax credit DTA. Company-owned projects have been modeled with an expectation of transferring the credits and have included a realistic "transaction cost" for the credits to reflect the costs of executing these transactions. This transaction cost has been informed by the Company's work-to-date on transferability and the contracts it expects to sign for the transfer of tax credits later this year. Thus, there is no DTA impact expected or modeled for the portfolios in this Report.

Additionally, prior to the IRA, solar generation was only eligible for the ITC, which is an upfront tax credit based on the construction cost of the facility. Utilities had to amortize the value of this credit over the life of the project, leading to lower financial benefit to customers (i.e., the loss of the time value of money). The PTC is not subject to the same amortization requirements as the ITC for utilities so utilities can pass the benefit back to customers the year the PTC is generated, which results in overall lower costs for customers. Both provisions in the IRA provide significant customer benefit in the forms of lower costs, which is evident in the pricing of the Company-owned projects.

IPPs are Strong and Active Partners in the Preferred Plan

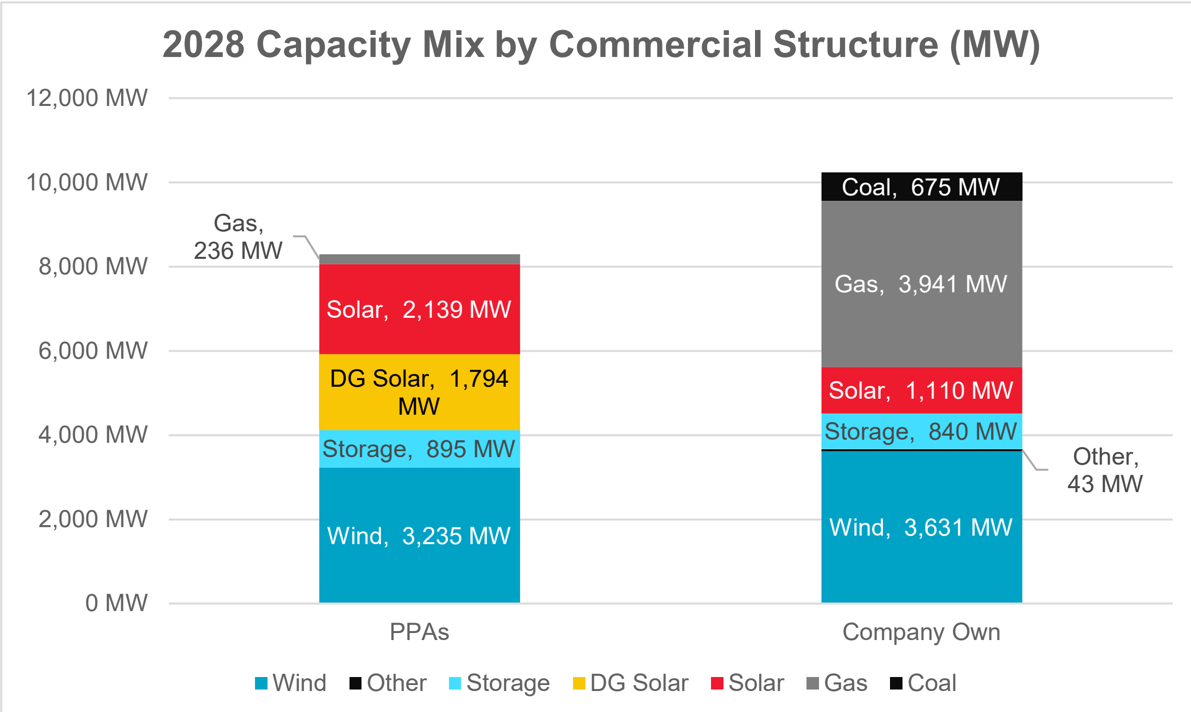
As evidenced by the over 1,000 bids received in response to the RFP, the IPP community rose to the challenge of propelling Colorado to achieving its emissions reduction goals and keeping customer costs low. In addition to the nine power purchase agreement ("PPA") projects included in the Preferred Plan, two of the Company-owned projects are build-own-transfer ("BOT") projects. A BOT project is one in which an IPP develops and constructs the project, with the Company purchasing the fully developed facility at or near completion. These BOT projects enable the Company and customers to have access to projects they may not otherwise and provide an economic opportunity to the developer. This further increases the diversity of power supply development opportunities and supports a robust IPP community that has, and will continue to have, a key place in Colorado's energy industry.

Furthermore, the Company has partnered with the development community in bringing forward the robust and economic set of projects that compromise the self-developed portion of the Preferred Plan. For some projects that appear as "self-builds," there is a more nuanced commercial background behind it. More specifically, the Company has built upon the early development work done by other entities, and either purchased the development work outright, or partnered with the developer to bring the project to completion. Accordingly, while BOTs are one form of commercial structure with IPPs, there are earlier stage commercial transactions with IPPs as well that are reflected through projects in the Preferred Plan. These forms of commercial structures and opportunities can continue to ensure a vibrant and robust marketplace for power generation development in Colorado.

In total, IPP developers have a role or direct financial interest in all of the clean energy projects in the Preferred Plan. Of the 6,545 MW of clean energy projects in the Preferred Plan, *all are either BOT, PPA, or were purchased from IPPs by the Company earlier in the commercial lifecycle* (i.e., not a BOT but with an underlying commercial transaction). This means that IPPs have a commercial interest in 91% of the total nameplate MWs under the Preferred Plan.

Upon approval and completion of the Preferred Plan in 2028, the overall Public Service generation portfolio will be balanced with approximately 44.8% of the capacity and 37.5% of the energy served by IPP interests under PPA agreements. Figure 10 below shows the Public Service total system capacity mix by commercial structure by 2028.

Figure 10 – Public Service Total System Capacity Mix by Commercial Structure (2028)



With the Preferred Plan, the competitive landscape and desire for future generation development in Colorado is as robust as ever, serving as a model for the West and the country in procuring cost-effective generation and using competition and commercial collaborations to get there.

<u>Delivery Risk Considerations and the Back-Up Bid Process</u>

IPP projects bring benefits to the electric sector, including creating competitive pressures and broadening the scope of projects that can be brought forward for the benefit of customers. At the same time, IPP projects do have a different risk profile than would be expected from utility projects. IPPs generally rely on external financing to support their projects and have to both secure that financing and meet the obligations imposed by their backers. This often is done after successfully receiving an award in the ERP, thus the projects are typically "un-funded" in the bidding stage. Additionally, if conditions materialize prior to final construction that negatively impact the financial metrics for the project, IPP entities may need to cease development of the project and mitigate their losses.

These events can often be beyond the developer's control, and are not the result of malfeasance, yet nevertheless result in the project not contributing to the electric resource need as planned. This was seen most recently in the 2016 ERP, in which eight of the eleven approved Colorado Energy Plan Portfolio ("CEPP") projects were awarded to IPPs. Numerous projects either failed or were delayed in this process, as has been detailed in other proceedings, resulting in new proceedings to replace the projects or acquire short-term resources to meet resource adequacy needs. The failure or delay of these projects has created planning challenges for the Company in ensuring the timely and cost-effective supply of resources to serve the needs of our customers and exacerbated the capacity constraints facing the Company in 2023 and 2024.[22]

Given the critical nature of this solicitation, both from a reliability perspective[23] as well as meeting the statutory clean energy targets, it is essential to ensure that the projects selected actually materialize and support system reliability and emissions reductions. There are several processes in place to help mitigate this risk and the Company, and almost certainly the IPP community as well, wants to ensure that the projects selected are successful.

Extensive Due Diligence

The first line of mitigation is the due diligence process completed during the bid evaluation portion of this Phase II. The due diligence efforts are described more fully in Section 3.6, but both internal and external subject matter experts reviewed the bids, with particular focus on the bids advancing to later rounds of the process. Their review encompassed areas such as contracting/negotiating risk (i.e., reviewing bidders' proposed changes to the model agreements), environmental issues, credit worthiness, land access and site control, impact to culturally significant areas, procurement of major equipment, technology choice and performance expectations, transmission interconnection feasibility and cost, and impact to the Company's financial statements as operating or finance leases. Much work was done prior to advancing bids to computer modeling, and with the unprecedented size of the bid pool, due diligence activities continued throughout the evaluation period. Bids that raised due diligence concerns were further evaluated and provided the opportunity to clarify and/or cure deficiencies, and ultimately, relatively few bids were discarded. The IE took an active part in making decisions on bids that were deemed either ineligible or raised due diligence concerns and agreed with all decisions made.

Right of First Offer

A second mitigation tool is the inclusion of a Company right of first offer (often called a ROFO) in the model PPA that allows the Company to step into a failed project and take

[22] See Section III.A. of the Company's 2021 Electric Resource Plan & Clean Energy Plan Annual Progress Report filed in Proceeding No. 21A-0141E on March 31, 2023 for additional information.
[23] The Public Service system is currently not meeting the required reserve margin and has a firm capacity need of over 1,500 MW by 2028, largely due to retiring facilities, including coal units.

over development to bring the project to operation, with suitable compensation to the original developer. This is not a preferred approach but can be useful in certain situations where Company ownership could save an otherwise beneficial project.

Backup Bids

After the experience gained from the 2016 ERP, the Company proposed and was approved to develop a set of backup bids for this Phase II. These bids are intended to be pre-approved by the Commission as a set of projects to be “next in line” to replace a project in the approved portfolio if it fails. The designation of a robust backup bid pool greatly increases the likelihood that the Company will be able to acquire replacement projects as needed should projects in the final approved portfolio fail, and establishing a pool of backup bids will preserve competitive pressures on developers on pricing, and terms and conditions. The backup bid selection process was conducted as described in the Rebuttal Testimony of Company witness Mr. Jon Landrum, whereby the selected bids of certain technology types were removed, while locking in the other portfolio resources, and the next set of bids for that technology type were identified. The Company had to perform two sets of these runs to develop a robust backup bid pool, and the final recommended backup bids are shown in Table 7 below. This backup bid pool has a diversity of technologies and a strong mix of owned and PPA resources, giving the Company opportunity to replace “like for like” to the extent practicable, particularly on the technology side, in the event of a failure of a project in the Preferred Plan. It should be noted that to the extent a backup bid is necessary, transmission costs may change for the interconnection of the backup bid versus the original bid.

Table 7 - Backup Bids

Bid ID	Project Name	Technology	Nameplate MW	Ownership Structure	In-Service
0510	[redacted]	Gas	147	PPA	2027
0514	[redacted]	Gas	30	PPA	2026
0235	[redacted]	Gas	219	PPA	2027
0782	[redacted]	Solar	400	PPA	2027
1124	[redacted]	Solar	500	PPA	2028
0474	[redacted]	Solar	200	PPA	2028
0375	[redacted]	Solar	200	PPA	2028
1045	[redacted]	Solar + Storage	560/100	PPA	2028
1127	[redacted]	Solar + Storage	199/100	Own	2026
1003	[redacted]	Solar + Storage	300/200	Own	2026
0303	[redacted]	Solar + Storage	300/100	PPA	2028
0467	[redacted]	Storage	250	PPA	2028
1085	[redacted]	Storage	200	Own	2028
1024	[redacted]	Wind	603	Own	2026
1018	[redacted]	Wind	203	Own	2027
1016	[redacted]	Wind	554	Own	2026
0254	[redacted]	Wind	291	PPA	2026

Note: In-Service refers to the first summer the unit is available.

The Commission-initiated Pre-Construction Development Asset ("PCDA") structure is also a positive step towards developing alternative resource options. Unfortunately, few bidders selected the PCDA option in the bid package and no bids are being recommended by the Company for this PCDA structure. Nevertheless, the Company views this type of structure as a very positive step in resource procurement and intends to consider proposing the PCDA process or a similar process in the forthcoming Pueblo Just Transition Plan solicitation. This type of structure could provide resource options in the event of a project failure or be used to procure projects with longer development timelines, and the Company appreciates the Commission's foresight in developing this process and looks forward to analyzing potential approaches in future planning cycles.

Finally, as another factor indirectly related to risk mitigation, the current approved cycle of relatively rapid back-to-back solicitations, commencing with the Pueblo Just Transition Plan and resource solicitation coming in 2024,[24] provides a more rapid opportunity to "course correct" in the event of changed circumstances than the four-year ERP cycle normally would. Given the expected timeline of that proceeding, it would be

[24] Expected to initiate with a Phase I-type filing by June 1, 2024.

challenging to bring forward new construction projects earlier than a 2028 in-service date, however.

The Preferred Plan Uses the CPP and MVLE

The Phase I Decision and Commission Decision granting a Certificate of Public Convenience and Necessity ("CPCN") in Proceeding No. 21A-0096E for the CPP included the grant of a conditional CPCN for the MVLE. It directed a cost/benefit evaluation for the MVLE in the Phase II modeling to determine whether the projects seeking to interconnect to the MVLE are part of a cost-effective resource plan when the total cost of the MVLE is included.[25] This evaluation was accomplished by creating a capital project in the EnCompass model equivalent to the costs for the MVLE and requiring that the capital project be added to any portfolio that included bids that utilized the extension. In the normal optimization process the model uses, the model recognizes that the bids and MVLE project must be either included or excluded as a bundle and would determine the most economic outcome. As evidenced by the inclusion of MVLE bids in both the Preferred Plan and informational LCP as shown in Table 8, the availability of low-cost wind bids in the southeast portion of Colorado justifies the construction of the additional segment of the CPP to connect to the proposed Longhorn substation. Further, wind generation in the southeast portion of Colorado exhibits materially different generation patterns and will thus be a useful improvement to our system in adding geographic diversity to our overall renewable generation portfolio.

Table 8 - MVLE Bids in Preferred and Least Cost Plans

#	Bid Info	1 - Preferred Plan (SCC) Bid_IDs	3 - Least Cost Plan (SCC) Bid_IDs
1.	Wind 905 MW - 07/21/2027 COD	1026	1026
2.	Wind 302 MW - 12/17/2026 COD	1012	1012

To test the relative impact of adding the MVLE to the portfolio, a scenario that specifically did not include MVLE was developed. This scenario corresponds to Scenario 11 in the modeling framework set forth in Attachment 1 to the Updated Settlement Agreement. This scenario was created by reoptimizing the Preferred Plan while not allowing any bids that would utilize the extension to be selected. As can be seen in Table 9 below, the portfolio optimized excluding the MVLE costs $282 million more than the Preferred Plan.

[25] Decision No. C22-0459, at ¶ 373.

Table 9 - Comparison of Portfolios With and Without MVLE

Portfolios' Comparison of Key Characteristics

Nameplate Capacity (MW)	1 - Preferred Plan (SCC)	11 - Without May Valley Plan (SCC)
Biomass	19	19
Gas	628	647
Solar	1,969	2,169
Storage	1,170	1,420
Wind	3,406	2,803
TOTAL Nameplate Additions (MW)	7,192	7,058
Flexible Capacity (MW)	1,817	2,086
Colorado Power Pathway (CPP) Trx Utilization (MW)	4,411	4,058
CPP May Valley-Longhorn Extension Trx Utilization (MW)	1,206	-
Accredited Capacity (MW)	1,621	1,627
Section 123 Capacity (MW)	19	19
Owned Capacity (MW)	4,787	3,984
Owned Capacity (%)	66.6%	56.4%
Owned Energy (%)	69.7%	62.8%
Accredited Capacity Position		
2028 Capacity Position Long/(Short) (MW)	100	106
2028 Actual Reserve Margin (%)	19.7%	19.8%
Planning Period Present Value Revenue Requirement (PVRR) ($M)		
NPV Base Portfolio Costs ($M)	$ 41,708	$ 42,234
NPV Trx PO-PF Interconnection Costs ($M)	$ 130	$ 134
NPV Trx Network Upgrades for Delivery ($M)	$ 2,353	$ 2,104
TOTAL PVRR ($M)	$ 44,191	$ 44,473
PVRR Delta vs. Preferred Plan ($M)	$ -	$ 282
Emissions		
2023-2030 CO2 (M Tons)	69,322,272	69,345,169
2023-2055 CO2 (M Tons)	93,063,889	92,949,651
2023-2055 CO2 Delta vs. Preferred Plan (M Tons)	-	(114,238)
2030 CO2 Reduction from 2005 (%)	-87.4%	-87.4%
2023-2055 NPV CO2 at SCC ($M)	$ 6,288	$ 6,283
2023-2055 NPV Methane at SCM ($M)	$ 57	$ 56
TOTAL Present Value Societal Cost (PVSC) ($M)	$ 50,535	$ 50,811
PVSC Delta vs. Preferred Plan ($M)	$ -	$ 276
Other		
2023-2055 Natural Gas Burn (MMBtu)	648,263,108	644,764,741
2028 Renewable Energy MWh (%)	83.0%	82.5%

2.6 The Preferred Plan Executes on Just Transition

In Phase I of this ERP, the Commission approved a specific coal action plan via approval of the Updated Settlement Agreement.[26] The Preferred Plan, as with all portfolios presented in this Report,[27] incorporate the approved coal action plan from Phase I and includes the early retirements and conversion of the Company's remaining coal-fired generation plants. Specifically, the modeling includes the retirement of Comanche Unit 3 no later than January 1, 2031, with reduced operations beginning in 2025; the retirement of Craig 2 in 2028; the retirement of Hayden 1 in 2028 and Hayden 2 in 2027; and the conversion of Pawnee to natural gas no later than January 1, 2026. The Company recognizes and appreciates the efforts of the Commission and many parties' hard work to reach negotiated solutions on these outcomes, and the ongoing commitment to just transitions for the workforce and community associated with these retirements.

But these approved actions also require execution on a Just Transition; the Preferred Plan meets this charge.

Section 10 outlines the efforts the Company has and will undertake to provide a Just Transition for the communities and workforce impacted by the Preferred Plan and changing energy landscape. The discussion here focuses on the Preferred Plan, which serves as a significant economic catalyst for the communities where projects are located, and also has a broader positive impact from the jobs and supportive services created by the construction and ongoing operations of the facilities.

Table 10 below shows the estimated construction capital being deployed at the county level, and Table 11 translates this into an estimated annual tax revenue.

[26] Phase I Decision, at ¶¶ 63, 75.
[27] Excluding the Reference Case.

Table 10 - Preferred Plan Generation Investment Location

County	Investment ($M)[28]
Adams	$902
Alamosa + Saquache	$574
Baca	[redacted]
Cheyenne + Kit Carson	$1,663
Kiowa + Prowers	$1,418
Morgan	[redacted]
Pueblo	$2,121
Routt	[redacted]
Sedgwick	$1,317
Weld	$1,456

Table 11 - Preferred Plan Impacts on Taxing Authorities

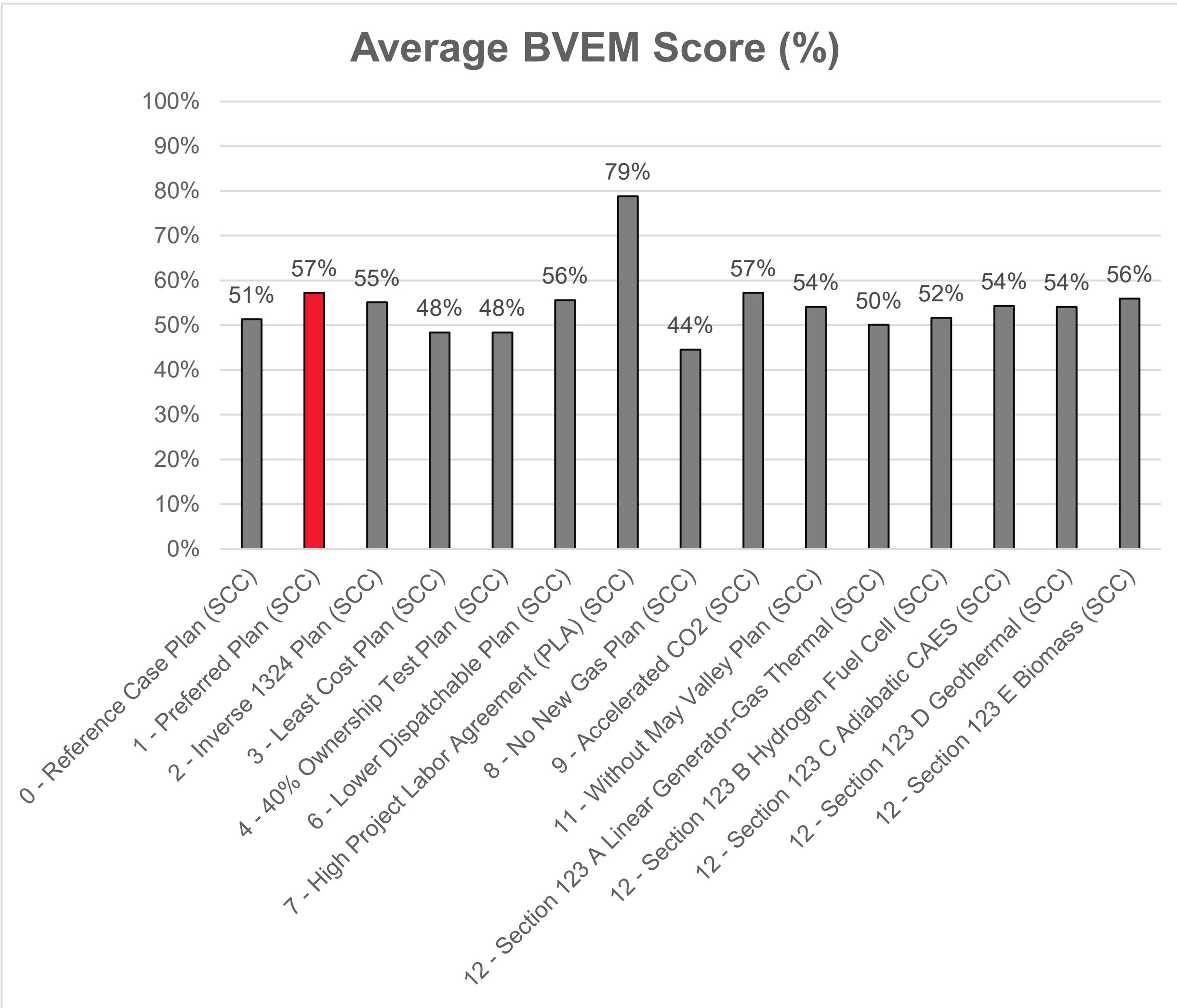
County	Estimated Tax Revenues ($M)
Adams	$2.8
Alamosa + Saquache	$2.6
Baca	$2.6
Cheyenne + Kit Carson	$2.7
Kiowa + Prowers	$2.4
Morgan	$1.3
Pueblo	$4.6
Routt	$0.1
Sedgwick	$2.5
Weld	$11.1

The Preferred Plan also has a relatively high best value employment metrics ("BVEM") score from the Labor Economist evaluation than other portfolios, indicating it creates higher quality jobs. The cumulative BVEM score of the Preferred Plan compared to other primary portfolios are shown in Figure 11 below. The Preferred Plan has the highest cumulative BVEM score compared to the other portfolios, with the exception of the High Project Labor Agreement ("PLA") portfolio, which was specifically constructed to maximize the BVEM score given a proposed PLA automatically satisfies the BVEM criteria under the terms outlined in the RFP. Table 12 shows the cumulative scores for

28 For counties with only single projects the total investment is provided as Highly Confidential information.

all the primary portfolios both using the SCC and with \$0CO2.[29] (See Section 9 for further discussion regarding BVEM.)

Figure 11 – BVEM Score of Primary Portfolios



29 Social cost of carbon, or "SCC," portfolios employ an externality value in the optimization. Portfolios referred to as "\$0CO2" do not have that value in the optimization. Many portfolios are presented using both to show how the value affects resource selection.

Table 12 - BVEM Scores of All Primary SCC and $0CO2 Portfolios

Scenario	SCC Avg BVEM Score (%)	$0CO2 Avg BVEM Score (%)
0 - Reference Case Plan	51.3%	53.1%
1 - Preferred Plan	57.2%	48.6%
2 - Inverse 1324 Plan	55.1%	48.0%
3 - Least Cost Plan	48.4%	52.3%
4 - 40% Ownership Test Plan	48.4%	*not modeled*
6 - Lower Dispatchable Plan	55.6%	47.0%
7 - High Project Labor Agreement (PLA)	78.8%	82.3%
8 - No New Gas Plan	44.5%	43.4%
9 - Accelerated CO2	57.2%	*not modeled*
11 - Without May Valley Plan	54.1%	54.7%
3 - Least Cost Plan - Extreme Weather	48.6%	*not modeled*
8 - No Gas Plan	44.5%	45.2%

2.7 The Preferred Plan Has Options

The Preferred Plan is a strong plan in the public interest that solves for numerous objectives, from emissions reduction to reliability, to just transition. To ensure the Commission has a complete picture in analyzing potential approaches, however, the Company has developed additional options for the Preferred Plan for consideration. The first is a Preferred Plan without the Hayden Biomass project, while the second is a modified Preferred Plan designed to prepare the system for prospective new loads. Each is discussed below.

Hayden Biomass Project

We described the significant benefits of the Hayden Biomass project in Section 2.5, and the Company strongly believes the project should be approved and included in the final portfolio. However, should the Commission determine that the biomass project is not in the public interest, the Company ran a Preferred Plan portfolio that included all the other bids in the Preferred Plan locked in, but the biomass unit excluded. The model was allowed to add extra resources to replace the biomass project, but not "go backwards." This run is intended to represent Portfolio 2 of the approved Phase II bid portfolios, the with/without HB 21-1324 resources. Although not necessarily an HB 21-1324 resource, the with/without biomass evaluation complies with the spirit of the portfolio development framework, i.e., showing a portfolio with a clean firm technology resource located in a community affected by the clean energy transition and a portfolio without that resource. In addition, as the Hayden Biomass project is a Section 123 resource, we also analyzed it using the methodology approved for evaluation of Section 123 resources, namely a full optimization. Those results are presented in Section 7. The result was that an additional solar resource was added to the portfolio, as shown in the comparison below.

In the event the Commission decides to not approve the Hayden Biomass project, the Company recommends approval of this alternate portfolio (i.e., Inverse 1324 Plan (SCC)).

Table 13 - Evaluation of Hayden Biomass Project

Portfolios' Comparison of Key Characteristics

Nameplate Capacity (MW)	1 - Preferred Plan (SCC)	2 - Inverse 1324 Plan (SCC)
Biomass	19	-
Gas	628	628
Solar	1,969	2,169
Storage	1,170	1,170
Wind	3,406	3,406
TOTAL Nameplate Additions (MW)	7,192	7,373
Flexible Capacity (MW)	1,817	1,798
Colorado Power Pathway (CPP) Trx Utilization (MW)	4,411	4,411
CPP May Valley-Longhorn Extension Trx Utilization (MW)	1,206	1,206
Accredited Capacity (MW)	1,621	1,613
Section 123 Capacity (MW)	19	-
Owned Capacity (MW)	4,787	4,768
Owned Capacity (%)	66.6%	64.7%
Owned Energy (%)	69.7%	67.8%
Accredited Capacity Position		
2028 Capacity Position Long/(Short) (MW)	100	92
2028 Actual Reserve Margin (%)	19.7%	19.6%
Planning Period Present Value Revenue Requirement (PVRR) ($M)		
NPV Base Portfolio Costs ($M)	$ 41,708	$ 41,429
NPV Trx PO-PF Interconnection Costs ($M)	$ 130	$ 130
NPV Trx Network Upgrades for Delivery ($M)	$ 2,353	$ 2,353
TOTAL PVRR ($M)	$ 44,191	$ 43,911
PVRR Delta vs. Preferred Plan ($M)	$ -	$ (280)
Emissions		
2023-2030 CO2 (M Tons)	69,322,272	69,249,725
2023-2055 CO2 (M Tons)	93,063,889	92,709,788
2023-2055 CO2 Delta vs. Preferred Plan (M Tons)	-	(354,101)
2030 CO2 Reduction from 2005 (%)	-87.4%	-87.5%
2023-2055 NPV CO2 at SCC ($M)	$ 6,288	$ 6,269
2023-2055 NPV Methane at SCM ($M)	$ 57	$ 56
TOTAL Present Value Societal Cost (PVSC) ($M)	$ 50,535	$ 50,236
PVSC Delta vs. Preferred Plan ($M)	$ -	$ (299)
Other		
2023-2055 Natural Gas Burn (MMBtu)	648,263,108	643,281,194
2028 Renewable Energy MWh (%)	83.0%	83.2%

Prospective New Load Scenario

One challenge with the ERP process is that it is designed to acquire resources based on a static snapshot of load projections developed at the beginning of the RFP. Especially in today's landscape with new large loads developing at a much faster pace than seen before, such as data centers, crypto currency customers, and wholesale entities looking for new suppliers, this process is not well equipped to adjust to rapidly changing conditions. The ERP process does not typically factor in potential, yet not guaranteed, load additions, and the changing customer needs call for more planning flexibility.

Currently, the Company is in active discussions with numerous entities that could potentially become large new retail or wholesale customers in the near term, i.e., during this RAP. To account for this new load, at least some of which would be better described as "more likely" than "possible," the Company created a modified Preferred Plan ("Prospective New Load Preferred Plan") that included a potential new load of 300 MW beginning in January 2026. This load has a load factor roughly equivalent to the current system, and was modeled at 60% load factor. Based on the strong possibility of the specific load being considered, or one very similar, before the next opportunity to acquire resources, the Company is recommending the Commission allow the Company to use the backup bid pool to serve this load if needed. The top four bids to serve this new load are in the backup bid pool and are shown in Table 14 below. If this new load materializes, the Company would provide notice to the Commission that it is commencing negotiations with these bidders, with Rule 3617(d) applying to these actions (along with any other backup bid-related actions). This Prospective New Load Preferred Plan is shown below in Table 15, with a comparison to the Preferred Plan.

Table 14 - Backup Bids Utilized for Prospective New Load

Bid ID	Project Name	Technology	Nameplate MW	Ownership Structure	In-Service
0235	[redacted]	Gas	219	PPA	2027
0474	[redacted]	Solar	200	PPA	2028
0467	[redacted]	Storage	250	PPA	2028
1085	[redacted]	Storage	200	Own	2028

Note: In-Service refers to the first summer the unit is available.

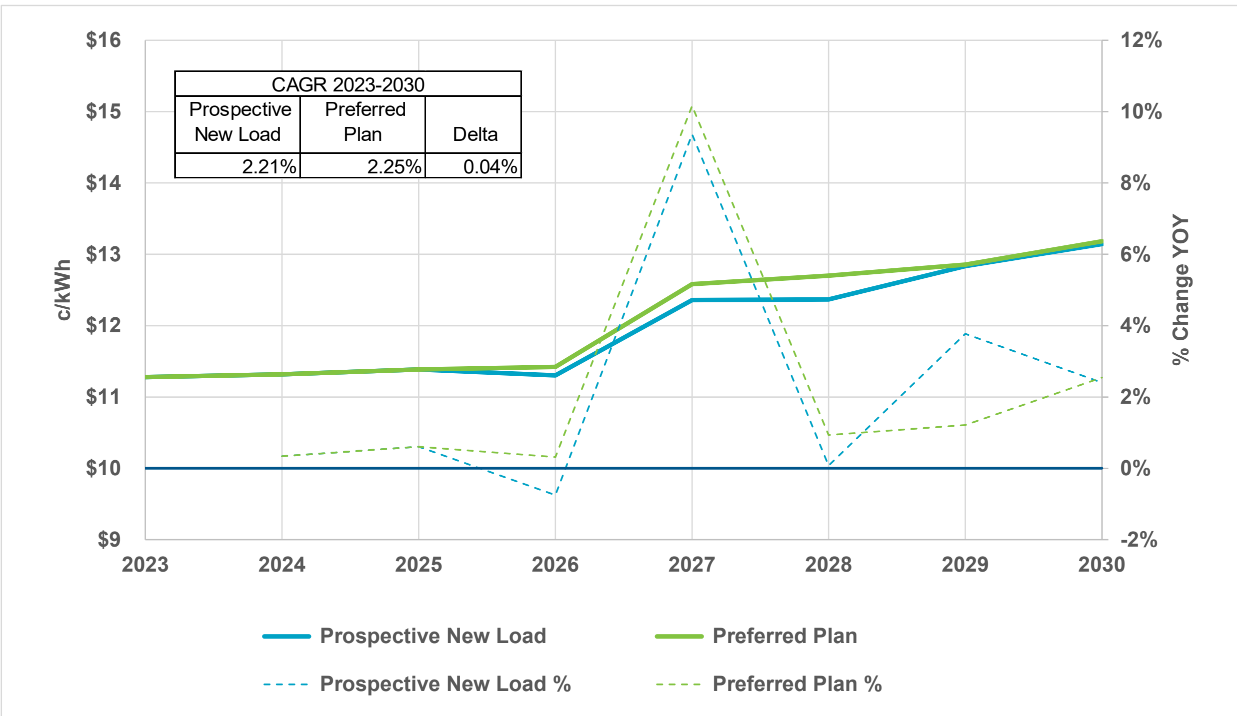
Table 15 - Preferred Plan Comparison to Prospective New Load Preferred Plan

Portfolios' Comparison of Key Characteristics	1 - Preferred Plan (SCC)	1 - Preferred Plan (SCC) - with Prospective New Load
Nameplate Capacity (MW)		
Biomass	19	19
Gas	628	847
Solar	1,969	2,169
Storage	1,170	1,620
Wind	3,406	3,406
TOTAL Nameplate Additions (MW)	7,192	8,061
Flexible Capacity (MW)	1,817	2,486
Colorado Power Pathway (CPP) Trx Utilization (MW)	4,411	4,661
CPP May Valley-Longhorn Extension Trx Utilization (MW)	1,206	1,206
Accredited Capacity (MW)	1,621	1,877
Section 123 Capacity (MW)	19	19
Owned Capacity (MW)	4,787	4,987
Owned Capacity (%)	66.6%	61.9%
Owned Energy (%)	69.7%	67.7%
Accredited Capacity Position		
2028 Capacity Position Long/(Short) (MW)	100	1
2028 Actual Reserve Margin (%)	19.7%	18.2%
Planning Period Present Value Revenue Requirement (PVRR) ($M)		
NPV Base Portfolio Costs ($M)	$ 41,708	$ 42,669
NPV Trx PO-PF Interconnection Costs ($M)	$ 130	$ 138
NPV Trx Network Upgrades for Delivery ($M)	$ 2,353	$ 2,353
TOTAL PVRR ($M)	$ 44,191	$ 45,160
PVRR Delta vs. Preferred Plan ($M)	$ -	$ 969
Emissions		
2023-2030 CO2 (M Tons)	69,322,272	70,542,352
2023-2055 CO2 (M Tons)	93,063,889	95,767,052
2023-2055 CO2 Delta vs. Preferred Plan (M Tons)	-	2,703,162
2030 CO2 Reduction from 2005 (%)	-87.4%	-86.9%
2023-2055 NPV CO2 at SCC ($M)	$ 6,288	$ 6,452
2023-2055 NPV Methane at SCM ($M)	$ 57	$ 60
TOTAL Present Value Societal Cost (PVSC) ($M)	$ 50,535	$ 51,672
PVSC Delta vs. Preferred Plan ($M)	$ -	$ 1,137
Other		
2023-2055 Natural Gas Burn (MMBtu)	648,263,108	683,765,944
2028 Renewable Energy MWh (%)	83.0%	82.8%

Since the costs for the Prospective New Load Preferred Plan also reflect the fuel costs for serving this new load in addition to the resources themselves, a comparison of the rate impact of the two portfolios is more meaningful than a direct comparison of the PVRR/PVSCs.[30] This rate impact is shown in Figure 12. As can be seen from the Figure, adding the new load lowers overall rates, from a cumulative average growth rate (or, CAGR) of 2.25% for the Preferred Plan to a rate of 2.21% for the new load scenario.[31]

This is an important finding, as it indicates adding the new load and resources to serve it lowers overall rates and is net beneficial to the system and all customers.

Figure 12 – Rate Impact of Prospective New Load



CAGR 2023-2030		
Prospective New Load	Preferred Plan	Delta
2.21%	2.25%	0.04%

[30] "PVSC" stands for "Present Value of Societal Costs," which is determined post modeling by multiplying the carbon and methane emissions by the appropriate social costs. The PVRR results with the social costs of emissions included are labeled "PVSC."

[31] These figures do not account for incremental transmission needed to serve the portfolio, depending on the nature and location of the new load added to the system.

2.8 The Preferred Plan is in the Public Interest

This ERP cycle differs from prior cycles because the Company is able to include a Clean Energy Plan as part of its filing. The Preferred Plan is the Company's Clean Energy Plan under Colorado law, and the Phase I Decision noted that the Commission must make certain public interest findings in this proceeding.[32] Specifically, § 40-2-125.5(4)(d), C.R.S. requires the Commission to consider:

> (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.

The Phase I Decision addressed the need to make these findings, and further addressed the findings required in § 40-2-125.5(4)(d)(III), C.R.S., stating:

> Essentially, the Commission must consider the net present value of the projected costs associated with the CEP (*i.e.*, the projected cost of its implementation) including any projected savings. This analysis looks at whether the implementation of the CEP as a whole, results in a reasonable cost to customers—not just those costs that can be recovered via the CEP Rider. In other words, the Commission will consider the NPV revenue requirement (or NPVRR) of all aspects of the CEP.[33]

The Commission also found that:

> To ensure that we can make the required public interest findings in Phase II, including whether the CEP results in a reasonable cost to customers as evaluated on an NPV basis, Public Service shall clearly delineate in each optimized portfolio the various categories of costs and savings set forth in

[32] Phase I Decision, at ¶ 317.
[33] Phase I Decision, at ¶ 318.

the statute. Public Service must also do this for the Phase II ERP portfolio.[34]

The Company will provide emissions information, a reliability and resiliency assessment, and net present value ("NPV") cost information for each presented portfolios later in this Report. Here, for the Preferred Plan that the Company recommends for approval, the Company steps through each in turn.

Emissions Reductions Under the Preferred Plan

The Preferred Plan has modeled emissions reductions well in excess of the statutory 2030 clean energy target of 80 percent emissions reductions below 2005 levels by 2030. The Preferred Plan modeling shows an 87% emissions reduction by 2030, with 82% achieved within the RAP, which runs through end of year 2028. This compares favorably to the ERP portfolios, both with and without the SCC. Without the SCC, the ERP "business as usual" or Reference Case portfolio projects to achieve an emissions reduction of 69% by 2030. With the SCC, the ERP "business as usual" or Reference Case portfolio projects to achieve an emissions reduction of 75% by 2030.

The Preferred Plan features higher modeled emission reductions than the ERP portfolios, which supports a public interest finding under this provision of the statute.

Reliability and Resiliency of the Preferred Plan

The statute directs a review of the feasibility, reliability, and resiliency of a Clean Energy Plan. This is one area where the Preferred Plan differentiates itself from smaller ERP Reference Case portfolios and other larger plans (e.g., the informational LCP , the No New Gas Plan, and the No Gas Plan).

First, the Company subjected portfolios to an extensive reliability review through a rubric discussed earlier in Section 2.3. The rubric was designed to test the feasibility, reliability, and resiliency of each portfolio. The Preferred Plan, with extensive renewable and storage deployments coupled with strategically located dispatchable assets, passed each stage of these reliability tests.

Second, the Preferred Plan has substantially less gas resources than SCC10-USA (628 MW versus 1,372 MW) and more wind, solar, and batteries (6,545 MW in the Preferred Plan versus 4,350 MW in SCC10-USA). In addition, it includes a dispatchable clean energy investment in the Hayden community that was not included in SCC10-USA, building on the just transition commitments to our affected communities from Phase I

[34] Phase I Decision, at ¶ 320.

and setting an example for the country of how to transition the power system and provide opportunities for our communities and workforce at the same time.

Third, the Preferred Plan differs from the informational LCP in subtle but important ways. Both plans contain roughly the same amount of gas resources, but the Preferred Plan has natural gas resources in beneficial locations that provides enhanced reliability and resiliency to the system. Indeed, this outcome is illustrative in that it shows one of the reasons why the Commission does not do least cost planning. Least cost planning is not designed to solve for reliability and resiliency variables. The Preferred Plan does, and it is superior to the informational LCP in this regard.

Fourth, the Preferred Plan provides better reliability and resiliency benefits than the much larger and more expensive No New Gas Plan and No Gas Plan, as explained in more detail later in this Report. These portfolios are both thousands of MWs larger and substantially more expensive than the Preferred Plan, and the Company believes there is material reliability risk and operational uncertainty associated with either one; therefore, these portfolios are infeasible from an operations perspective. Further, the statute provides that the Commission "shall not approve any plan that does not protect system reliability," and the Company believes neither the No New Gas Portfolio nor the No Gas Portfolio protect system reliability and therefore cannot be approved by law. In sum, the Preferred Plan compares well from a reliability and resiliency standpoint as compared to the No New Gas and No Gas Portfolio.

Finally, the ERP portfolios are not unreliable; however, they do not capture the emissions reduction or just transition benefits of the Preferred Plan. There is no reliability benefit to either ERP portfolio compared to the Preferred Plan.

Each of these five comparative points support a finding, based on analytics in this proceeding and extensive reliability testing by the Company, that the Preferred Plan is feasible, reliable, resilient, and in the public interest when viewed through this lens.

The Preferred Plan and Reasonable Cost

The Preferred Plan comes at reasonable cost when assessed on an NPV basis against other portfolios and from an estimated bill impact standpoint.

The Preferred Plan performs well against the informational LCP; indeed, it is a more reliable and resilient portfolio and comes at an NPV of $44.169 billion (Preferred Plan) versus $43.962 billion (informational LCP), which is an incremental cost of $207 million or a change of about 0.5%. A salient comparison from a statutory perspective is the Preferred Plan versus two "business as usual" ERP reference cases, one with the SCC and one without the SCC. Importantly, both of these reference cases are sizeable from a generation addition standpoint and require either all or a vast majority of the transmission investment to interconnect the portfolio, as detailed in Section 6.

When compared with the $0/ton ERP "business as usual" reference case, the difference in NPV going out to 2055 is $44.169 billion as compared to $43.262 billion. This amounts to a change of 2% or $907 million—while projecting to achieve a 69% emissions reduction from 2005 levels by 2030. This latter point is key, as this portfolio would not qualify the plan for the statutory "safe harbor," subjecting the system to additional air quality regulation that would likely eviscerate the projected NPV savings. The lack of a "safe harbor" leads to the risk of dual and potentially conflicting regulation, as well as resource planning directives from another agency to comply with any power sector regulations.

Another key comparison is the Preferred Plan to the ERP "business as usual" *with the SCC* in the optimization, which produces a portfolio with an NPV of $44.011 billion. This again compares to a Preferred Plan NPV of $44.169 billion, a difference of $158 million or 0.35%. This SCC view of the ERP "business as usual" portfolio is sizeable, requiring the same transmission build as the Preferred Plan while achieving only a 75% emissions reduction from 2005 levels by 2030. This portfolio would technically qualify for the "safe harbor" under statute, but it leaves substantial investment for the future to continue to make progress towards the statewide emissions reduction goals.

Finally, the Preferred Plan results in projected savings. A comparison of the Preferred Plan with the $0/ton ERP "business as usual" reference case is appropriate, as it illustrates the path forward under the Preferred Plan against an alternate, "policy free" future. In looking at total fuel costs under the two plans, the $0/ton ERP "business as usual" reference case has an NPV for total fuel costs between 2023-2030 of $2.419 billion. The Preferred Plan, on the other hand, has an NPV for total fuel costs over the same time period of $2.246 billion—a savings of nearly $175 million on an NPV basis through the end of the decade. The savings are even more pronounced over the planning period, where the $0/ton ERP "business as usual" reference case has an NPV for total fuel costs between through 2055 of $5.936 billion. The Preferred Plan has an NPV for total fuel costs of $4.893 billion over the same period. The result is savings of over $1 billion on an NPV basis over the planning period in total fuel costs, a clear benefit of the Preferred Plan over the $0/ton ERP "business as usual" reference case.

These comparisons establish that the Preferred Plan comes at reasonable cost while meeting the clean energy targets, capturing substantial projected emissions reductions with a modest impact on an NPV basis. Moreover, when compared with a "policy free" pathway to meet resource needs, it captures over $ 1 billion in NPV savings on total fuel costs.

The Preferred Plan is in the Public Interest

The General Assembly directed Commission review across three general categories to evaluate whether a plan is in the public interest. The Preferred Plan satisfies each element by exceeding the 2030 statutory clean energy target, maintaining a reliable and resilient system, and achieving these two objectives at reasonable cost. The Preferred

Plan meets the statutory criteria for the public interest, and the Commission should make each finding and approve the Preferred Plan accordingly.

The Preferred Plan is the most transformational step yet in the clean energy transition. It is set to deliver on the clean energy policies of the State – reliably and affordably – while also establishing a foundation for future resource planning cycles. Getting to this point is like training to get to the starting line of a triathlon. We are excited, we have a support team at the ready, we understand the challenges, and we are looking forward to taking them on with a good plan in place. But that does not mean that implementation and execution of the plan will be easy, and unknown challenges lie ahead given the breadth of generation and transmission development contemplated by this plan. Timing coordination after the Commission's Phase II decision will be one of the key elements, including the processing of the regulatory activities that start upon the Phase II decision being issued.

3.0 Model and Modeling Methodology Updates

3.1 Independent Evaluator Coordination

The Company has worked in close coordination with the Independent Evaluator ("IE") throughout the entirety of the bidding process, including the RFP solicitation, bid receipt, and bid evaluation process to ensure the process was fair and in full alignment with conditions set out by the Commission. The Company consulted with the IE throughout the Phase II process consistent with ERP Rules and Commission decisions by engaging in scheduled weekly meetings and other meetings as needed to work in lockstep together. See Appendix B for additional information regarding IE coordination.

3.2 Modeling Enhancements from Phase I

As set forth in Section 2.14 of Volume 2 of the 2021 ERP & CEP and the Commission's Phase I Decision, the Company provided updated modeling assumptions and/or methodologies used in Phase II in the Updated Modeling Inputs & Assumptions document filed on November 29, 2022. This document presented a comprehensive summary of the modeling assumptions that were either updated or had not changed from the Phase I filing as required by paragraph 316 of Decision No. C22-0459.

In addition to basic assumption updates, the Company also identified several improvements to the model and modeling processes to allow for more accurate and detailed evaluations of the bid portfolios. These enhancements are described in the sections below.

<u>Curtailment Modeling</u>

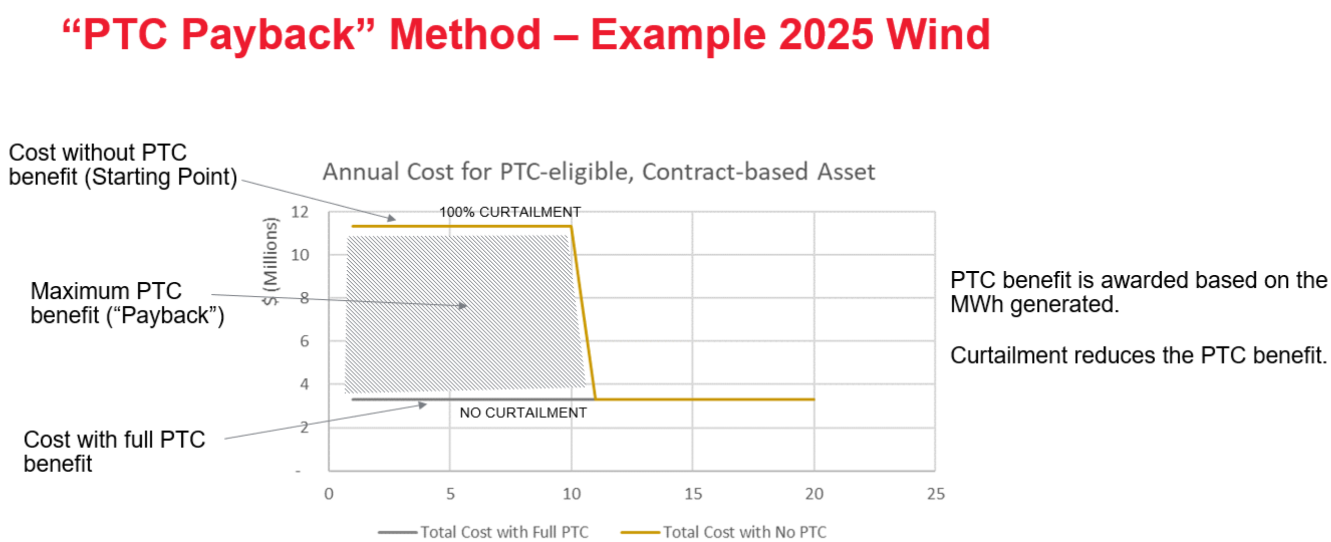
The Company collaborated with various stakeholders prior to the commencement of Phase II to develop and incorporate a methodology to include the cost impacts of PTCs and curtailment into the Phase II modeling. The aim of the curtailment modeling enhancements, further referenced as the "PTC Payback" method, was to capture lost PTC payments due to curtailments and economically allocate curtailment to resources within the model optimization. In addition, the enhancements enable EnCompass to consider the true costs of curtailment and make optimal decisions on the overall balance of increased curtailments associated with increased renewable generation.

The default setup in EnCompass is to simply calculate the amount of curtailment required when generation from "must-run" resources (including wind and solar resources) exceeds the load plus storage charging capability and transmission export capability. EnCompass then utilizes Curtailment Groups (identified as part of the resource inputs) to prioritize curtailment allocations to the groups and reduces the must-run generation on a pro-rata basis within a particular group. Effectively, the default curtailment approach is a "post-processing" step, and the model optimization will not consider PTC impacts.

The PTC Payback method allows the optimization to consider the value of PTCs and the costs of curtailment when simulating the system dispatch. PTC-qualifying wind and solar resources are treated as dispatchable resources, and the energy price ($/MWh) is converted to an annual fixed cost ($/year)[35] without the PTC benefit. In other words, the fixed cost is what would be payable if the resource operated at its expected capacity factor but was 100% curtailed.

Next, the PTC value ($/MWh) is set as a negative variable energy cost for the resource for the first ten years,[36] so the model optimization will view this as an incentive to operate the resource. Doing so means the resource receives the value of the PTC for the first ten years of operation when dispatched, but if a curtailment is required, the PTC will not be captured for that amount of generation. The model will economically determine the order and amount of the curtailment based on minimizing overall system cost. Additionally, in the capacity expansion modeling, the model simultaneously evaluates the impacts of adding a resource and the amount it will be curtailed, so the economic balance of adding incremental generation versus incremental curtailments is fully evaluated. Figure 13 below provides an illustrative example of the PTC Payback methodology:

Figure 13 – Illustrative Example of PTC Payback Methodology



[35] This conversion is done by multiplying the energy price by the expected annual generation (dictated by the resources annual-average net capacity factor).
[36] The PTC eligibility period.

Colorado's Power Pathway (CPP) Transmission Constraints

For Phase II modeling, a simplified transmission topology and flow limits by year were implemented within EnCompass to represent the impact of the CPP.[37] Existing and currently planned 2016 ERP resources were merged into a single transmission area ("PSCO Area") and were not modeled with any transmission-related congestion or curtailments. A second transmission area ("CPP Area") was created to reflect the transmission area subject to flow limitations associated with the CPP. These flow limits change annually during the construction period of the CPP, ranging from zero prior to the commercial operation date ("COD") of the first segments, to 3,700 MW when fully constructed. Based on the results of the due-diligence review, bids were placed in the CPP Area if planned to interconnect into the CPP and would be subject to the overall flow limitations of the transmission project. Other projects were placed in the PSCO Area if not subject to the CPP limitations. This simplified topology approach allowed EnCompass to optimize the timing, quantity, and type of generation added and economically determine the optimal level of generation added on the CPP versus expected congestion and curtailments. This is an improvement as compared to Phase I where no transmission flow limits were used, and congestion was not captured.

Full Optimization & Removal of Maximum Resource Caps

An additional benefit of the topology improvements described above was the removal of the annual capacity addition constraints applied to generic resources from years 2025 to 2027 in Phase I. These were used in Phase I to approximate the impact of the construction schedule for the CPP. With the addition of CPP flow limits, the constraints around capacity additions were removed and EnCompass was able to fully optimize during these years.

3.3 Model Assumption Updates

Due to provisions outlined in the Updated Settlement Agreement and/or modifications made necessary from Commission decisions and/or Settlement Agreements in other proceedings associated with planning criteria, there were several updates needed that were not contemplated or included in the Updated Modeling Inputs & Assumptions ("Updated Modeling Assumptions") filing that occurred on November 29, 2022, contemporaneously with the issuance of the RFPs (provided as Appendix D). Consistent with Paragraph 316 of the Phase I Decision requiring any assumptions updated after issuance of the RFP but prior to the Phase II resource evaluation be provided in the 120-Day Report, the Company discusses the further inputs and assumptions updates below.

[37] As described in Hr. Ex. 124, Rebuttal Testimony and Attachments of Jon T. Landrum, Rev. 1, at pgs. 100-107, filed November 12, 2021 in Proceeding No. 21A-0141E.

Load Forecast

The Company's most current annual demand and energy forecast was presented in the Updated Modeling Assumptions. In the Company's ERP Annual Progress Report filed on March 31, 2023, the Company noted corrections to two spreadsheet errors it identified in its forecast. The first error resulted in solar peak values being shifted by one year, resulting in native peaks ranging from 25-38 MW higher than intended through 2032. The second error failed to include line losses for peak contributions from two new large individual customers, but these errors largely offset, resulting in less than 1 MW of changes to peaks. The corrected demand and energy forecast for a ten-year period is summarized in Table 16 below.

Table 16 - Demand and Energy Forecast

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Annual Native Load Energy Sales (GWh)	33,312	33,815	34,437	34,172	34,919	35,821	36,676	37,752	38,894	40,299
Summer Native Load Peak Demand (MW)	7,107	7,157	7,224	6,960	7,037	7,136	7,247	7,374	7,502	7,659

Demand Response Forecast

On July 1, 2022 the Company filed its Demand Side Management ("DSM") Strategic Issues application in Proceeding No. 22A-0309EG, which sought, in part, approval of its 2024-2027 demand response ("DR") goals. On January 19, 2023 the Company filed its Rebuttal Testimony in the same proceeding and updated its DR goals to be for the years 2024 through 2026. In its Rebuttal Case, the Company proposed to increase both its annual summer and winter electric DR goals by 55 MW and 10 MW, respectively. By Decision No. C23-0413 in Proceeding No. 22A-0309EG, the Commission ordered an increase of DR goals in 2025 and 2026 over the Rebuttal Case. A summary of the DR goals presented and approved in Proceeding No. 22A-0309EG are shown in Table 17 below.

Table 17 - Public Service's Proposed Demand Response Goals

		Direct Case		Rebuttal Case		As Approved	
		Summer	*Winter*	*Summer*	*Winter*	*Summer*	*Winter*
Annual DR Goals (MW)	*2024*	538	271	593	281	593	281
	2025	563	291	618	301	628	301
	2026	597	324	652	334	663	321

Because Commission Decision No. C23-0413 was received after the Company had finalized its Phase II modeling inputs, the Company used the goals proposed in its Rebuttal Case for the Phase II modeling.

Comanche 3 Costs

In Paragraph 84 of its Phase I Decision, the Commission approved the provisions in the Updated Settlement Agreement regarding Comanche Unit 3's operations and maintenance ("O&M") expenses, with the understanding that the O&M values used in Phase II would include the reasonably foreseeable increase in O&M that will be attributed to Unit 3 when Units 1 and 2 retire. The Commission further noted that it was unclear whether the O&M expenses listed in the Updated Settlement Agreement (i.e., a variable O&M of $2.20/MWh and fixed costs at $24.076 million per year) included common cost allocations from Units 1 and 2. Therefore, the Commission directed Public Service to work with Staff prior to Phase II to develop a Comanche Unit 3 O&M forecast that incorporates common cost allocations from Units 1 and 2. Accordingly, the Company conferred with Staff prior to Phase II and agreed upon the appropriate Comanche Unit 3 O&M values to use in the Phase II modeling. These values are provided as Highly Confidential Appendix O.

The Comanche 3 capital additions were updated to match the latest forecast for the 2030 retirement. The increase from Phase I to Phase II is driven by the latest estimate for the auxiliary boiler required during the planned overhaul in 2024. The Phase II forecast also includes higher inflation impacts.

Deferred Tax Asset Modeling

By Decision No. C23-0522-I, the Commission directed the Company to confer with Staff and provide an update regarding DTA issues, including the results of the conferral process, the DTA forecast, if available, and the planned treatment of DTA in the Phase II modeling. As discussed in its response to Decision No. C23-0522-I (provided as

Highly Confidential Appendix F and Appendix F), the Company worked with Staff both in this proceeding and in Proceeding No. 22AL-0555E to address the impacts of the PTC transferability provisions of the IRA. The tariff approved in Proceeding No. 22AL-0555E facilitates the transfer of PTCs from existing Company-owned and PTC-eligible wind projects to the benefit of customers and underpins a modeling approach to account for PTC transferability in Phase II of this proceeding. The IRA transferability provisions will mitigate and eventually eliminate the DTA associated with unused PTCs from the Company's currently owned wind projects (i.e., Rush Creek and Cheyenne Ridge) and will prevent any new PTC DTA from being created with new Company-owned projects via transferability.

Accordingly, the modeling approach used for Phase II assumes the transfer of all PTCs at an expected transfer cost in the modeling of Company-owned, eligible resources in Phase II. This modeling approach ensures that the transfer cost of all PTCs (and ITCs as applicable) is embedded in the revenue requirement of Company-owned projects for purposes of bid evaluation and portfolio development, which ensures that these costs are accounted for on a project-by-project basis. Simply put, the net present value of any resource portfolio includes the transfer costs for all Company-owned, PTC/ITC-eligible resources. The Company used an assumed transfer cost as identified in Highly Confidential Appendix F, which is the Company's estimated average transfer cost for PTCs based on its work in the market to find buyers for its PTCs and discussions with others in the industry.[38]

3.4 Modeling Challenges

Numerous challenges and unforeseen issues were encountered during Phase II when actual modeling of the bids advanced to computer modeling commenced. These issues were a significant part of the need for the second extension to the filing of this Report. Most of these issues were the result of an unprecedented number of bids received in Phase II and the number of bids advanced to computer modeling (over 380). The sheer number of options available created challenges with the software solving and greatly increased model run times to an unworkable level.

This challenge was first encountered during initial portfolio development using the capacity expansion functionality of EnCompass. Initial runs would fail to complete, even after multiple days, with the mixed integer programming ("MIP") Stop Basis[39] tolerance never being reached.

[38] The estimated transfer cost is "bid information" and therefore is highly confidential, consistent with the protective order issued in this proceeding through Decision No. C21-0343-I.

[39] The MIP Stop Basis is the defined level of solution precision where the model considers the problem "solved".

Reduced Time Block Granularity

Following numerous tests and a meeting with the software vendor and the IE on June 22, 2023, agreement was reached to incorporate a further aggregation of hours when performing capacity expansion model runs. Specifically, the number of daily intervals modeled was reduced to 11 total time blocks per day versus the 24 per day (i.e., every hour) initially used for the on-peak/off-peak optimization period. The vendor confirmed that the aggregation proposed would not fundamentally alter the validity of the analysis results. Specifically, the number of daily intervals modeled was reduced to 11 total time blocks per day versus the 24 per day (i.e., every hour) initially used for the on-peak/off-peak optimization period. This additional aggregation of hours resulted in 264 (11*2*12) intervals being solved per year versus 576 (24*2*12) intervals. It should be noted that this aggregation of hours was only applied to capacity expansion modeling for selection of bids for the portfolios and not for the production costing used to estimate overall portfolio costs, which was done using the full 8,760 hours per year granularity. The reason the capacity expansion process, versus production costing, requires this additional aggregation of hours is because of the much larger problem size EnCompass must solve when determining capacity selections.

Eliminating Symmetry

While the aggregation of hours helped to lower the number of variables being evaluated with the EnCompass software, additional model simplifications were needed to ensure that the computer modeling portion of the bid evaluation could be completed in a timely manner. When utilizing modeling software that is based on MIP such as EnCompass, one issue that can impact the ability of the solver to complete has to do with the concept of "symmetry." Symmetry exists when too many solutions look the same due to similar objective function coefficients and/or similar constraints. In other words, the model has trouble reaching a solution because different variables are defined with identical data and the solver is indifferent as to the selection and effectively becomes unable advance the analysis. An example of this phenomenon occurring within this bid evaluation is seen with the "PTC Payback Method." Since wind and solar resources are modeled in Phase II as dispatchable resources by converting variable energy costs into a fixed annual cost and the variable energy cost represents the value of the PTC credit, multiple projects can have identical energy costs. This can cause the model to have an issue with choosing which projects to utilize to meet a constraint (such as load) due to the model being indifferent to the resource selection. To disrupt such symmetry, a very small "epsilon" adjustment was introduced on the cost coefficients of numerous variables.[40, 41] These epsilon values did not fundamentally impact the data but allowed

[40] As an example, "epsilon" values for $/MWh variables were less than 0.0025 $/MWh.

[41] This methodology is cited in academic literature as a practical approach for combating symmetry in mathematical programs (*see* Appendix N). *See* also: Hanif D. Sherali, J. Cole Smith, (2001) Improving

the model to navigate to a solution. The values are so small compared to "actual" resource values/costs that they do not impact resource selection at all, and these values were removed when performing the production cost runs to ensure they did not affect the dispatch.

It should be noted that both the hourly aggregations and symmetry model simplifications were tested to ensure the changes did not influence the outcome of the evaluation and reported to both the IE and Commission Staff during the evaluation period.

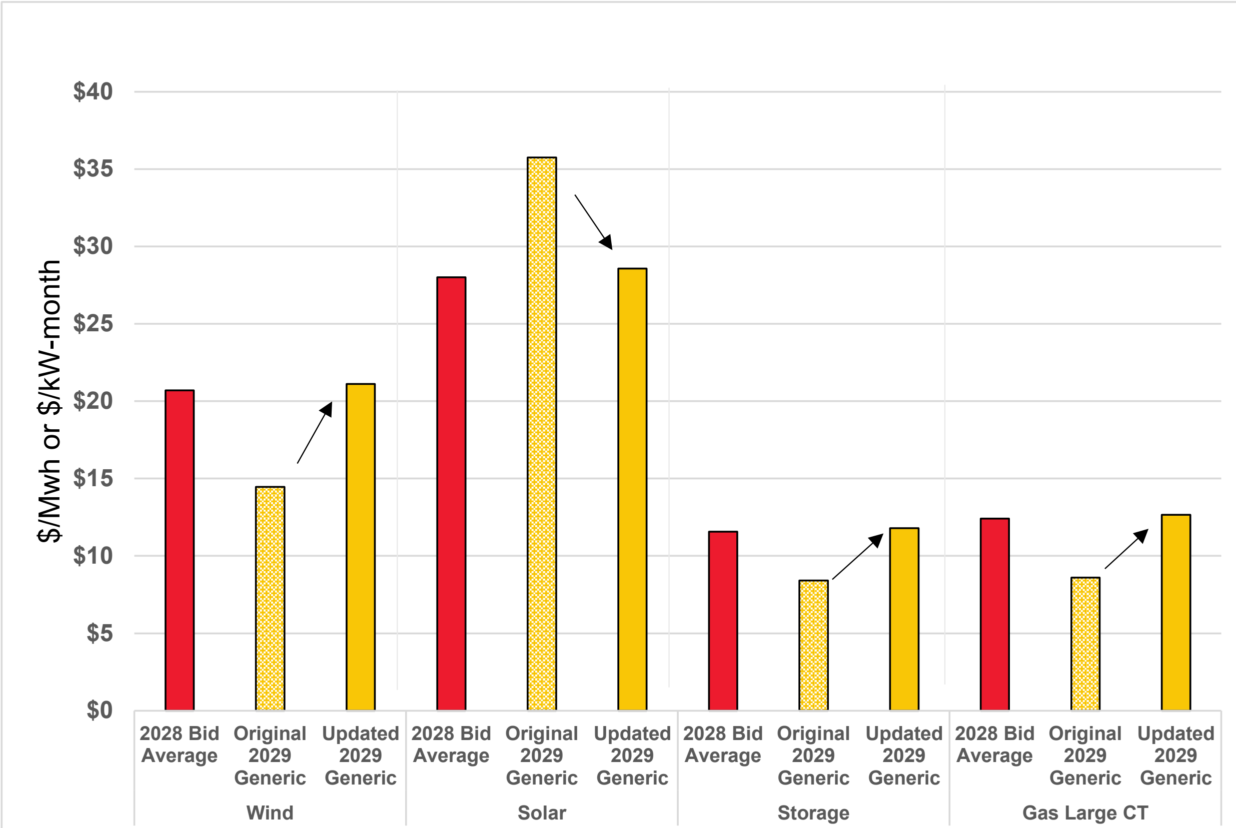
Generic Project Pricing in 2029 & 2030

As presented in the Updated Modeling Assumptions document, the Phase II modeling relied on the 2021 National Renewable Energy Laboratory Annual Technology Baseline ("NREL ATB") (adjusted for the IRA) for generic project pricing in the later years of the RAP, specifically 2029 & 2030. Initial capacity expansion modeling, however, showed a large amount of generic project selections occurring in those years as EnCompass was choosing to maximize the selections of those generic resources due to very low pricing as compared to the bids. This generic pricing was substantially lower than the actual bids received during the solicitation, and not deemed reflective of actual market conditions.

The Company consulted with the IE, and jointly decided that, to promote a fair comparison of actual projects versus generic resources, the generic prices should be recalibrated to the median price of actual bids received (by technology) with these prices applied to the corresponding generics for the years 2029 and 2030. The result of this change generally resulted in less generic selections during the final years of the RAP with only generic options selectable, and more selections of actual projects in the earlier periods of the RAP. Figure 14 below shows the original and revised 2029 generic pricing compared to the average bid price for 2028. The prices for 2030 generics were the 2029 prices escalated by 2%.

Discrete Model Representations via Symmetry Considerations. Management Science 47(1):1396-1407, at https://doi.org/10.1287/mnsc.47.10.1396.10265.

Figure 14 – Original and Calibrated Generic Pricing



Best in Class Testing

To further evaluate the large number of bids advanced to computer modeling, EnCompass was used to determine a "first cut" to reduce the number of bids advancing to further rounds of computer-based modeling. A very similar process was also used in the 2018 Phase II evaluation of the 2016 ERP to conduct an initial computer evaluation of the advanced bids. The process for this Phase II evaluated each technology class (wind, solar, storage, hybrid, and thermal) separately by utilizing the partial unit optimization feature of EnCompass to solve for the least-cost portfolio comprised solely of that technology class. Projects were selected to be advanced further in this initial selection process, or "best in class" approach, by determining if any partial amount of a unit was picked by the model as part of a least-cost solution. Those selected were included in the final bid list used for the development of the final portfolios. In the event multiple versions of the exact same project[42] were selected, only the highest-ranking version was moved forward. This methodology ensured that EnCompass was used to

[42] Multiple bids with the exact same size, COD and technology were considered "the same." Most often, this consists of bids for the same project with either fixed pricing or escalating pricing.

evaluate all bids advanced to computer-based modeling, while at the same time reducing the final number of bids used in portfolio creation to a more manageable amount.

3.5 Reliability Testing and Modeling

Another modeling challenge was encountered when initial capacity expansion portfolio results were reviewed following the model enhancements discussed above. Specifically, the base runs[43] generated were not able to pass the reliability criteria. As discussed in Section 2.3, these criteria consisted of serving load and ancillary services during the hot summer and cold winter scenarios developing using actual historical data, as well as meeting the PRM approved in the Phase I Decision.

The underlying cause of the base runs not being reliable are the base inputs themselves (as described in the Updated Modeling Assumptions provided as Appendix D). The load forecast assumed in the base runs was developed assuming typical meteorological year ("TMY") data, along with the directed planning reserve margin and standalone ELCC assumptions. Historically, the ELCC and PRM studies are conducted as a cohesive analysis, and the values produced are valid over portfolios that are reasonably consistent with the assumptions used in those studies. The studies incorporate varying levels of load and renewable production, and should capture the effects of historic outlier events, so long as they are within the data sets being used for the analyses.

However, when the portfolios were "stress tested" for hotter and colder weather conditions by performing an hourly production cost for 2028, the model was reporting unserved energy and ancillary service violations during these periods. Furthermore, the portfolio ELCC check for resource adequacy was similarly reflecting a low portfolio ELCC which did not meet the PRM and thus indicated an unreliable portfolio.

The ELCC values decided in Phase I, including the supplemental storage ELCC study conducted according to the provisions of the Updated Settlement Agreement,[44] were not providing the model with accurate information to develop reliable portfolios. As an initial test, the Company conducted capacity expansion runs using the original storage ELCC values from its ELCC study submitted in Direct Testimony[45] but these values did not produce portfolios that met the reliability criteria. The most likely factor is the level of intermittent renewables and limited duration storage in these portfolios, which are testing the limits of the data used, and the values produced, by the ELCC and PRM

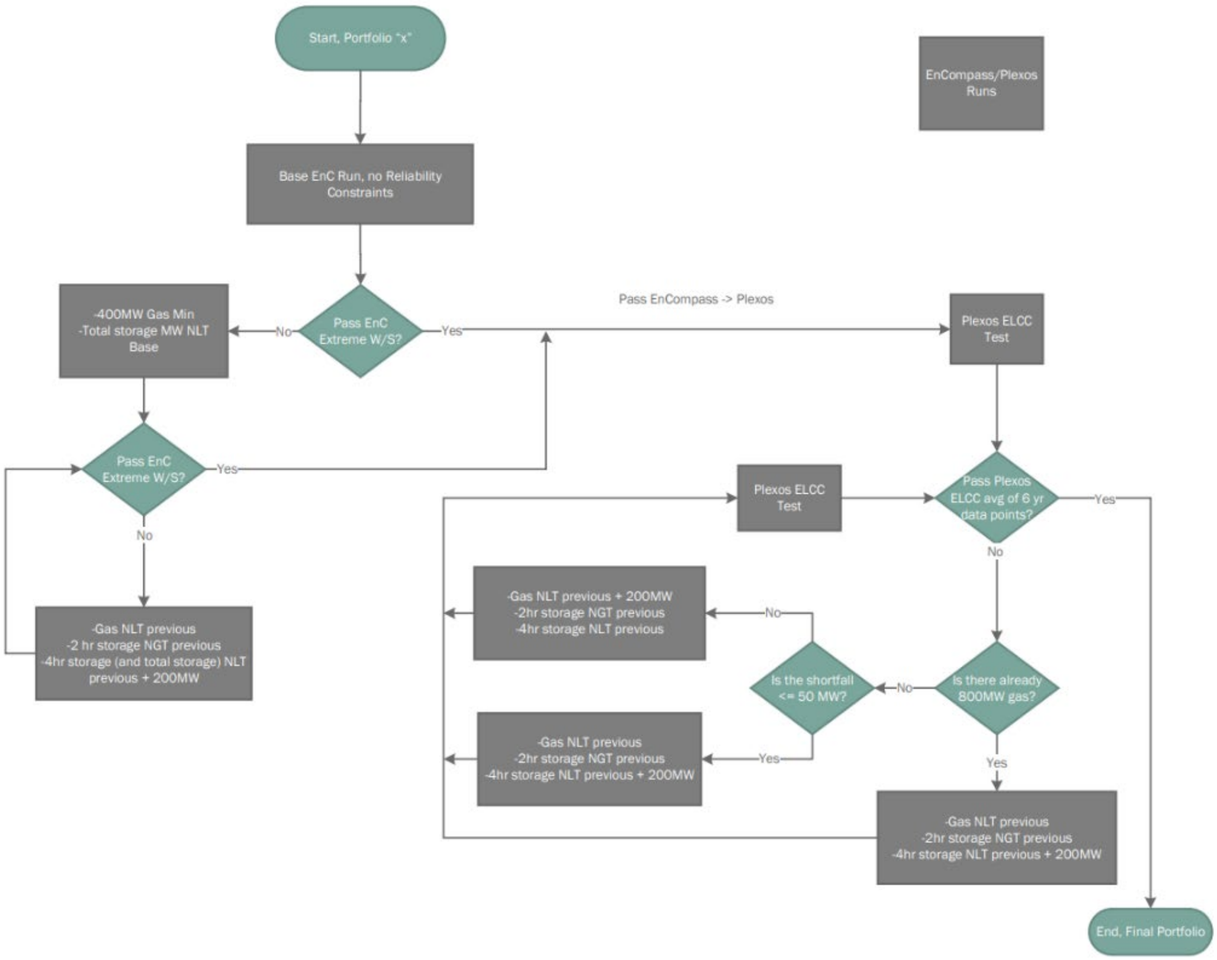
[43] The term "base run" is used throughout to denote the initial capacity expansion plans produced by the model using only the Phase I assumptions and without additional reliability additions. The term is synonymous with "raw model output."
[44] See the Updated Settlement Agreement at ¶ 5.
[45] Attachment KLS-2 to the Direct Testimony of Company witness Mr. Kent Scholl.

studies. Additionally, the EnCompass model is only able to capture ELCC curves for technologies on an individual basis, and not capture the interdependencies different generation resources and their effects on ELCC. This effect is most profoundly observed with storage. The model has individual ELCC curves for different durations of storage (i.e. 2-hour and 4-hour storage have unique curves), and does not reflect the very real fact that adding 2-hour storage reduces the ELCC of subsequent additions of 4-hour storage (and vice versa). There is a similar interdependency with other types of resources, and at the levels being added in these portfolios, that interdependency is often detrimental to ELCC, that is the ELCC of the combined portfolios is less (in this case much less) than predicted by the sum of the ELCCs determined on a standalone basis.

Reliability Rubric

To ensure the portfolios being developed were reliable and able to be compared on a similar basis, an unbiased "reliability rubric" was created as discussed earlier in Section 2. The rubric was created to formalize the process of developing reliable portfolios using the tools available to the Company, specifically both EnCompass and Plexos. The rubric is shown below as Figure 15, and also included in Appendix E for further clarity.

Figure 15 – Reliability Rubric



<u>Development of the Rubric as the Method to Create Reliable Portfolios</u>

As discussed above, the EnCompass model, using the agreed upon Phase I assumptions, did not produce portfolios that met reliability targets on the first pass. The Company tested many options to produce reliable portfolios before ultimately settling upon the rubric, as described above, that resulted in being able to complete all the required portfolios. One option tested was to meet the reliability criteria using only non-gas resources, which resulted in 3,700 MW of storage additions and a total portfolio of over 13,000 MW of resources being added—at a cost of $5.4 billion more than the Preferred Plan. This is clearly not the most economic alternative and would result in much higher customer bills with essentially the same environmental achievement. It would also likely require a new and substantial level of transmission investments, which are addressed to some degree in this analysis, but the full implications in cost and implementation are well beyond the scope of this Report.

The Company also tested what would be necessary to pass the Commission's requested extreme summer scenario, which was developed based on guidance given by the Commission and originally analyzed in the Company's Supplemental Direct Testimony. The amount of new gas needed to pass this test is over 800 MW, exceeding the amount recommended in the Preferred Plan, and also requires an additional 200 MW more storage than the Preferred Plan.

Table 18 below shows the modeling results for the No Gas Plan and informational Least Cost Plan when solving for the Extreme Summer scenario. The Extreme Summer scenario requires more gas than the Preferred Plan, and the No Gas Plan results in significant overbuild of resources and extremely high costs as compared to the Preferred Plan.

Table 18 - Reliability and Makeup of Alternate Portfolios Tested

Portfolios' Comparison of Key Characteristics

Nameplate Capacity (MW)	1 - Preferred Plan (SCC)	8 - No Gas Plan (SCC)	3 - Least Cost Plan (SCC) - Extreme Weather
Biomass	19	-	-
Gas	628	-	819
Solar	1,969	2,903	2,369
Storage	1,170	3,699	1,620
Wind	3,406	6,423	3,406
TOTAL Nameplate Additions (MW)	7,192	13,025	8,214
Flexible Capacity (MW)	1,817	3,699	2,439
Colorado Power Pathway (CPP) Trx Utilization (MW)	4,411	9,159	4,861
CPP May Valley-Longhorn Extension Trx Utilization (MW)	1,206	2,370	1,206
Accredited Capacity (MW)	1,621	1,531	1,908
Section 123 Capacity (MW)	19	-	-
Owned Capacity (MW)	4,787	6,269	4,940
Owned Capacity (%)	66.6%	48.1%	60.1%
Owned Energy (%)	69.7%	56.8%	65.9%
Accredited Capacity Position			
2028 Capacity Position Long/(Short) (MW)	100	9	387
2028 Actual Reserve Margin (%)	19.7%	18.3%	24.2%
Planning Period Present Value Revenue Requirement (PVRR) ($M)			
NPV Base Portfolio Costs ($M)	$ 41,708	$ 47,007	$ 41,940
NPV Trx PO-PF Interconnection Costs ($M)	$ 130	$ 223	$ 138
NPV Trx Network Upgrades for Delivery ($M)	$ 2,353	$ 2,353	$ 2,353
TOTAL PVRR ($M)	$ 44,191	$ 49,582	$ 44,431
PVRR Delta vs. Preferred Plan ($M)	$ -	$ 5,392	$ 240
Emissions			
2023-2030 CO2 (M Tons)	69,322,272	62,282,423	68,624,386
2023-2055 CO2 (M Tons)	93,063,889	72,272,523	90,045,317
2023-2055 CO2 Delta vs. Preferred Plan (M Tons)	-	(20,791,366)	(3,018,572)
2030 CO2 Reduction from 2005 (%)	-87.4%	-94.0%	-88.3%
2023-2055 NPV CO2 at SCC ($M)	$ 6,288	$ 5,104	$ 6,121
2023-2055 NPV Methane at SCM ($M)	$ 57	$ 34	$ 53
TOTAL Present Value Societal Cost (PVSC) ($M)	$ 50,535	$ 54,721	$ 50,605
PVSC Delta vs. Preferred Plan ($M)	$ -	$ 4,185	$ 70
Other			
2023-2055 Natural Gas Burn (MMBtu)	648,263,108	369,977,093	599,454,737
2028 Renewable Energy MWh (%)	83.0%	93.0%	84.1%

EnCompass Reliability Testing Using the Hot Summer/Cold Winter Scenarios

As described in the rubric, following the development of the base portfolio, the "cold winter" and "hot summer" production cost scenarios were performed. The cold winter scenario is based on actual conditions observed during Winter Storm Uri (2021) and reflected high load for a weeklong event in the month of February, as well as limited solar and wind resource production. The hot summer scenario is based on historical data from a hot week in July 2022, with the higher load levels and reduced solar and wind[46] production from the same time period. This new summer scenario was added to the existing extreme summer scenario[47] and designed to be more reflective of actual weather conditions experienced in recent history. The Company tested the portfolios under both the hot summer and extreme summer scenarios, but only considered the hot summer scenario as a pass/fail reliability test to determine viable portfolios as determined by both the EnCompass historically based weather scenarios and the Plexos PRM/Portfolio ELCC testing. This means the portfolio would be well in excess of the 18% PRM as approved in Phase I. This scenario provides useful information on the reliability of the portfolios under extreme events, and each portfolio was tested under this scenario, with the EnCompass ancillary service violations from the extreme summer scenario model runs shown by number of violation hours, maximum MW violation amount, and total amount of ancillary service violation energy presented below in Table 19. However, the hot summer, not the extreme summer was determined to be more consistent with the ordered planning criteria.

[46] The reduced production was primarily seen in wind.
[47] The "extreme summer" scenario is as described in the Company's Supplemental Direct Testimony and as ordered by the Commission in Decision No. C21-0395-I.

Table 19 - Extreme Summer Results

Scenario	Hours	Max MW	MWh
0 - Reference Case Plan (SCC)	5	195	638
0 - Reference Case Plan ($0CO2)	4	225	778
1 - Preferred Plan (SCC)	-	-	-
1 - Preferred Plan ($0CO2)	9	440	2,341
2 - Inverse 1324 Plan (SCC)	5	202	546
2 - Inverse 1324 Plan ($0CO2)	4	118	355
3 - Least Cost Plan (SCC)	10	661	3,642
3 - Least Cost Plan ($0CO2)	4	118	355
4 - 40% Ownership Test Plan (SCC)	-	-	-
6 - Lower Dispatchable Plan (SCC)	-	-	-
6 - Lower Dispatchable Plan ($0CO2)	-	-	-
7 - High Project Labor Agreement (PLA) (SCC)	5	185	499
7 - High Project Labor Agreement (PLA) ($0CO2)	9	440	2,341
8 - No New Gas Plan (SCC)	6	304	1,099
8 - No New Gas Plan ($0CO2)	8	406	1,893
9 - Accelerated CO2 (SCC)	8	399	1,872
11 - Without May Valley Plan (SCC)	9	456	2,255
11 - With May Valley Plan ($0CO2)	9	455	2,425
3 - Least Cost Plan (SCC) - Extreme Weather	-	-	-
8 - No Gas Plan (SCC)	9	449	2,300
8 - No Gas Plan ($0CO2)	5	223	831

The outputs from these scenarios were reviewed for unserved energy and ancillary service violations, and if any of these conditions existed in the outputs, the portfolios were adjusted in accordance with the rubric. For the first adjustment, the base amount battery storage (capacity amount in MW, not specific bids) was set as a minimum constraint going forward. Similarly, the capacity amount of natural gas projects selected in the base plan was set as a minimum constraint, along with an additional 400 MW of gas.

By setting both only minimum and incremental technology specifications and not dictating specific bids, EnCompass is being used to develop cost-effective portfolios that meet all required constraints, and the Company is not arbitrarily selecting specific bids. The capacity expansion process was repeated sequentially, adding incremental storage while not letting the amount of other resources "backslide," until the portfolios successfully passed the summer/winter tests with no unserved energy or ancillary services. Following the removal of any EnCompass reliability violations, the resulting portfolio was passed to Plexos modeling for portfolio resource adequacy checks.

<u>Natural Gas in the Portfolios and Rubric</u>

The addition of gas in the first step was based on extensive modeling and testing of combinations of portfolios that could successfully pass the summer/winter scenarios as well as meet the specific PRM. It became clear that the base EnCompass model outputs were not only deficient in passing the summer/winter reliability scenarios, but also very deficient in accredited capacity to meet the PRM successfully when passed to Plexos for ELCC testing (moving from the left half of the rubric to the right side). The example in Table 20 below shows the Portfolio ELCC review of the EnCompass base outputs[48] for the Preferred Plan and Least Cost Plans.

Table 20 - Example of Portfolio ELCC Review of EnCompass Base Outputs for the Preferred Plan and Least Cost Plans

2028 PRM Impact of Preferred and Least Cost Base EnCompass Outputs		
Plan	Preferred	Least Cost
Added Resources (Nameplate MW)		
2 - Hour Storage	598	598
4 - Hour Storage (Includes Hybrids)	572	572
Biomass	19	-
Gas	28	-
Solar (Includes Hybrids)	2,669	2,669
Wind	3,031	3,031
Total Portfolio Accredited Capacity	7,207	7,162
Native Load	7,136	7,136
Forecast DR	(679)	(679)
Obligation Load	6,457	6,457
Total Planning Reserve Margin	18%	18%
Target PRM	1,162	1,162
Com3 Backup	11	11
Target Capacity	7,630	7,630
Capacity Position	(424)	(468)
ELCC for Inc. 500 MW 4-Hour Storage	97	106
Marginal ELCC %	19%	21%

Using the Least Cost Plan base output, an addition of up to 2,000 MW of 4-hour storage beyond what was originally selected by the model was tested using 500 MW increments. This demonstrated that the marginal ELCC of 4-hour storage continues to decrease with further additions. As shown in Table 21 below, the average ELCC of an

[48] The first result from the model, at the beginning of the rubric and before any additions

additional 2,000 MW of 4-hour storage when added to the Least Cost Plan base output is 15%, and with that ELCC, the plan would still be short of the PRM requirement.[49]

Table 21 - Least Cost Base Output Test of 4–Hour Storage ELCC

Iteration	Resource	Installed MW	Cumulative Inc. MW	Average ELCC	Ave MW
1	4-Hour Standalone Storage	500	500	21%	106
2	4-Hour Standalone Storage	500	1,000	16%	78
3	4-Hour Standalone Storage	500	1,500	13%	66
4	4-Hour Standalone Storage	500	2,000	12%	58
	Total MW Added	2,000	2,000	15%	308

Furthermore, the Plexos results of both the EnCompass base outputs and the outputs from the step that passed summer/winter reliability indicated that marginal 4-hour storage was consistently following this trend, and incremental storage above what was already in the portfolios had an ELCC of around 20% or less. Since the storage and gas CT bids are very similarly priced in terms of $/kW-month, it would cost 5 times as much to correct an ELCC deficiency with storage on a MW-for-MW basis. For large shortfalls in accredited capacity, adding additional gas is clearly the most economic alternative.

These results showed clearly that portfolios that passed EnCompass were going to have at least 400 MW of gas added in the Plexos step. To capture this inevitable outcome and ensure that the benefits of the extra resources could also contribute to passing the summer/winter tests (possibly avoiding superfluous resources being added there), the decision was made to include these additions as the first measure in the EnCompass testing. This decision was borne out by the fact that all final reliable portfolios[50] ended up having at least 400 MW gas, and only a very few did not have even more gas resources (beyond the initial 400 MW) added by the Plexos testing phase to pass PRM.

It is important to note that just because new gas turbines are constructed, that does not lead to increased carbon emissions. The modeling shows the new units running at a capacity factor of less than 5%, thereby providing a critical reliability backup for those crucial times when renewables and storage cannot meet the needs of the system, as seen most often in periods of sustained hot or cold weather. The fast-start gas units ensure customers are served 24x7 and sit idle providing essential operating reserves and ancillary services when not needed to maintain load, all while producing zero emissions. Most importantly, the Preferred Plan that includes the new gas units is

[49] The plan was 468 MW short. An additional 2,000 MW of storage would add 2,000 * 15% or 300 MW of accredited capacity, which would still leave the portfolio short.
[50] Except the No New Gas portfolios.

projected to exceed the 80% carbon reduction by 2030 target, and the units do not negatively impact that result. In fact, including the gas units would likely *decrease* overall system carbon emissions by enabling larger amounts of renewable generation to be added, far outweighing the minimal carbon emissions coming from the units themselves. This investment is the "insurance" necessary to meet the reliability criterion required of us by our customers and this Commission.

Portfolio ELCC and PRM Verification Using *Plexos*

As discussed in Phase I[51] and described in detail above, the creation of bid portfolios within EnCompass is conducted using standalone ELCC values for non-firm resources. While the effect of incremental standalone additions of renewable or energy limited resources is reflected in these ELCC values, as observed in the modeling results and as previewed in the ELCC Study,[52] the ELCC results for portfolios do not typically equal the sum of the standalone ELCCs.

The same methodology and tools used to conduct the ELCC Study were used to determine the Portfolio ELCC inclusive of all renewable and energy limited resources, and were studied as a combination of the following sequential groups:

a. Standalone, renewable generation
b. All demand response resources
c. All standalone storage resources
d. All hybrid renewable generation and co-located storage resources[53]

The Portfolio ELCC for all presented portfolios was studied for the final year of the bid RAP (2028) and incorporated into a simplified representation of the Company's L&R Table. The goal of the Portfolio ELCC review is to ensure that the Company's PRM is met and that significant overbuild did not occur in the selection of portfolios. The Portfolio ELCC Review process is outlined as follows:

1. Plexos was updated to add any incremental thermal generators included in the studied portfolio to the existing thermal generators in 2028.
2. Existing and portfolio renewable generation and energy limited resources were added to the system model in the order as outlined in the groups above and an ELCC was determined for each annual study period.[54]

[51] Hearing Exhibit 101, Attachment AKJ-2_Technical Appendix, Rev.2, Section 2.16 "Portfolio ELCC Review."
[52] Hearing Exhibit 101, Attachment AKJ-2-E_ELCC Study Report, Rev.1
[53] Hybrid renewable generation and co-located storage resources were modeled together such that the interconnection limit could not be exceeded.
[54] Existing and proposed portfolio resources were counted in the Portfolio ELCC for 2028 as long as they contributed to Summer 2028 needs, defined as beginning July 1, 2028 in the RFP documents.

3. The resulting average ELCC of the renewable and storage resources were added to the L&R Table along with the Summer net dependable capacity ("NDC") of Thermal Resources to determine the total accredited capacity of the Company's resources in 2028.
4. The total accredited capacity was then compared to the Target Capacity.
5. If the Capacity Position was less than the Target Capacity, the studied portfolio was determined to not meet the Company's reliability goals. The portfolio would then be passed through the EnCompass model again, with constraints to increase the minimum capacity of storage (potentially could include hybrid bids) or gas in order to meet the Target Capacity in accordance with the rubric.

The decision to add either gas or storage to the portfolio was determined by reviewing the existing capacity shortfall, the marginal ELCC of incremental 4-hour storage, and the levelized capacity cost ("LCC") of typical storage and gas bids. As the levels of storage are different within each studied portfolio, the marginal ELCC of incremental storage was not always the same, but on average, if the capacity shortfall was greater than around 50 MW, a gas bid would be the most economic way to meet the Target Capacity.

To further aid the decision to add either gas or storage resources to make up a capacity shortfall, an incremental "test" 4-hour storage resource was added to the model after all the portfolio resources. The model can then provide both the ELCC of the actual portfolio, as well as the marginal ELCC of the test storage addition. Figure 16 and Figure 17 below show modeling runs where this test storage was added to a portfolio to determine the marginal ELCC of incremental 4-hour storage after all existing and portfolio resources were evaluated.[55] In each intermediate step presented,[56] the portfolio tested had a capacity position less than the target capacity, and only the base EnCompass output (which also failed summer/winter reliability tests in EnCompass) had a marginal ELCC greater than 20%. These results were used to determine whether gas or storage minimums in EnCompass would be increased for the next model iteration.

[55] All tests presented in Figure 16 and Figure 17 determined the marginal ELCC of 200 MW of 4-hour storage because most of the gas thermal bids received were about 200 MW of nameplate capacity. This provided a direct comparison between adding a CT or adding more storage resources.
[56] "Intermediate step" refers to a portfolio that was modeled by EnCompass but did not pass reliability checks, and therefore could not be considered a "final" portfolio.

Figure 16 - Total Energy Limited Resources and Marginal ELCC of Incremental Storage in Intermediate Portfolios - SCC

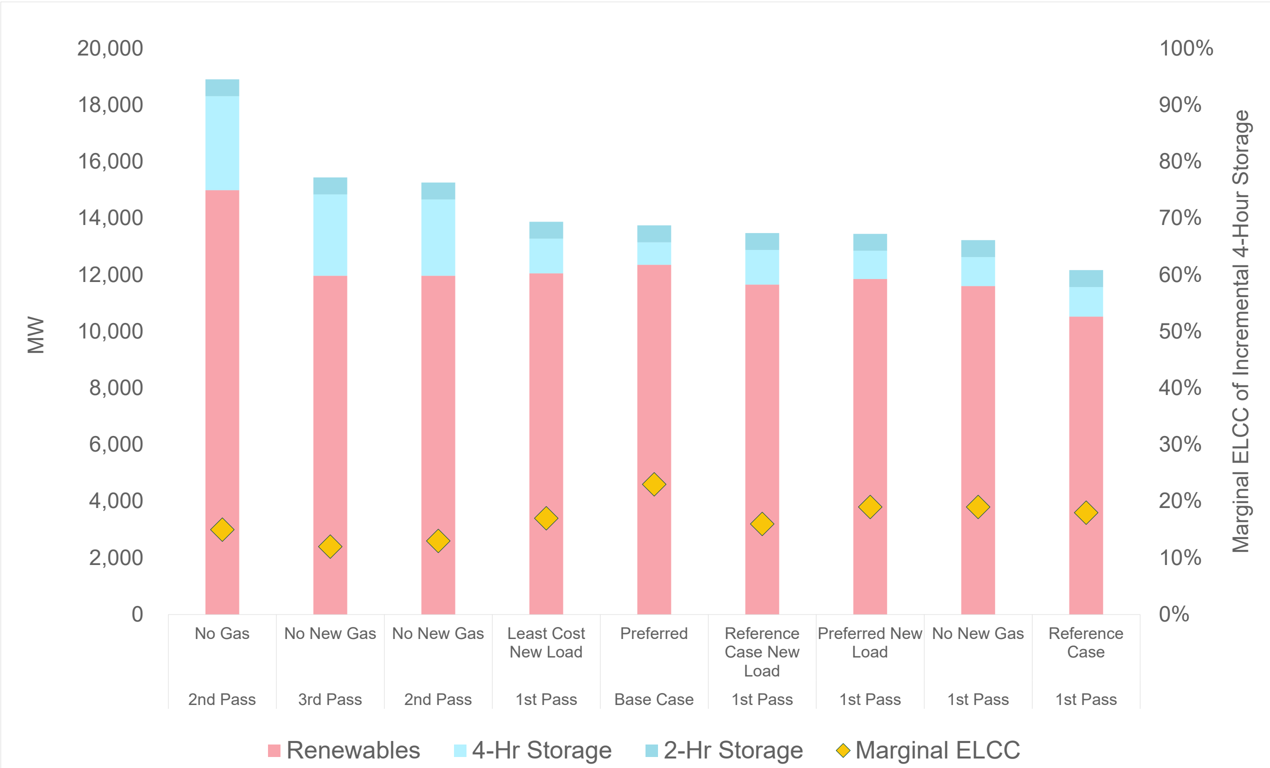
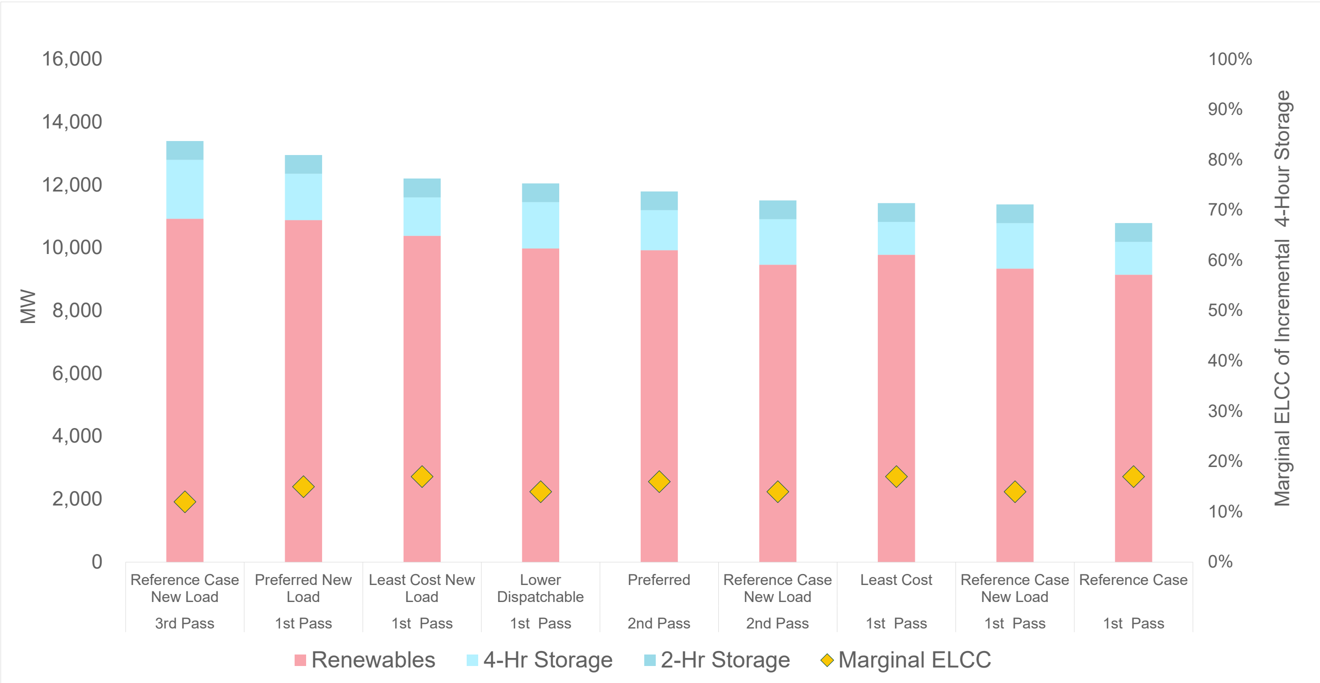


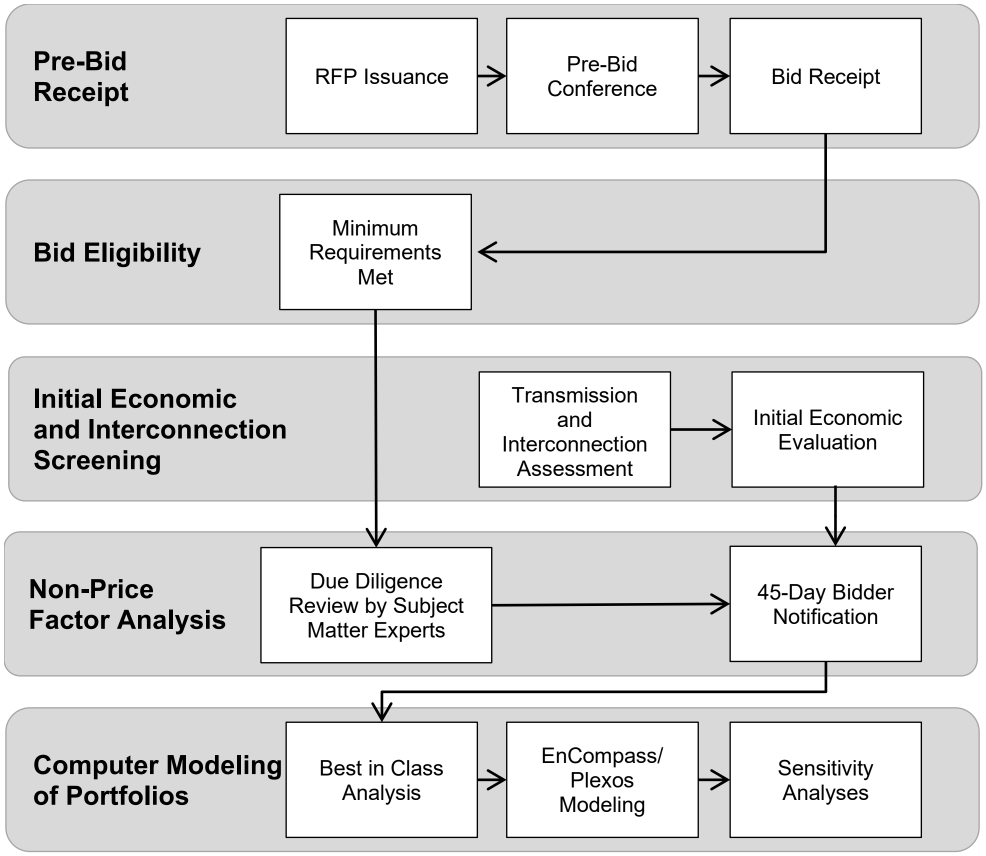
Figure 17 - Total Energy Limited Resources and Marginal ELCC of Incremental Storage in Intermediate Portfolios - $0CO2



3.6 Overall Evaluation Process

The Company evaluated bids in accordance with the evaluation process outlined in Section 5 of the RFP documents. Figure 18 below shows a general overview of the bid evaluation process. The sequential steps are described below in more detail. (See also Appendix B, Independent Evaluator Coordination and Appendix C, Phase II Process Overview).

Figure 18 – Bid Evaluation Process



<u>Bid Receipt</u>

The evaluation process began with the receipt of bids of Company bids on February 28, 2023 and the remainder of bids on March 1, 2023. The bids were held in an electronic file-share system with no personnel besides the Administrator of the file-share and uploading process having access to the bids until 4 PM on March 1. The Administrator provided a signed affidavit to the IE attesting to the confidentiality of the bids up to the release of bids to the evaluation team at that time.

<u>Bid Eligibility</u>

Upon release of the bids to the bid evaluation team, the team immediately began reviewing the bid packages. Initial tasks consisted of taking inventory of the bids received and categorizing and organizing the bids. Initial completeness reviews were conducted to ensure all required content from the RFP documents was included. Bidders were notified of any discrepancies and provided the opportunity to rectify any omissions.

Due Diligence

A broad due diligence team consisted of internal and external subject matter experts began evaluating the bids received. Initial efforts were focused on assessing project feasibility, identifying fatal flaws, and ensuring compliance with the provisions of the RFP. Due to the unprecedented volume of bids received, this process continued throughout the evaluation period. A high-level analysis was completed on all bids prior to advancing them to computer-based modeling, and as the number of bids under consideration was reduced through the evaluation process, the teams were able to conduct more detailed and focused due diligence reviews on the remaining bids.

One part of the due diligence process that was most challenging was the review of the bidders' proposed changes (i.e., redlines) to the model agreements—both the model PPAs and the model term sheets. Colorado does not have a "conforming bid" policy whereby bidders have to bid to the model agreements "as-is." This can make comparing bids on an equitable basis challenging when the performance guarantees, or risk provisions differ. It is difficult to quantify the cost impact of these provisions because it involves comparing competing bids' prices while weighing contractual differences.

Many bidders submitted changes that contradicted issues previously litigated and settled in Phase I or that have a longstanding basis as being non-negotiable by the Company. Some of these items include modifying the performance criteria and penalties for non-performance, altering the security payment provisions, or adding conditions precedent or termination rights that substantially increase the risk of failing to proceed to full construction and operation. The more problematic alterations would be considered due diligence red flags or even ineligible bids if contrary to litigated items that the Commission decided and included in its orders.

Any such items identified by the due diligence team were communicated to bidders and bidders were offered the opportunity to revise their redlines or to maintain them. If they maintained their position, bidders were asked to provide the cost impact of their changes and if signing a contract was dependent on acceptance, in accordance with the provisions outlined in the RFP for submitting changes to the model agreements.

Ultimately most of these issues were resolved satisfactorily, and no bids were discarded based solely on proposed contractual changes. The IE was involved in all decision making on whether a bid should be discarded or not. Nevertheless, resolving these issues took a significant amount of time from both the due diligence and bid evaluation team. The Company will look to the upcoming Pueblo Just Transition RFP process to seek consensus on identifying items in the agreements that are non-negotiable, including guidance from the Commission, and clarify those items in the RFP documents to hopefully streamline this process in the future.

Overall, due diligence teams reviewed the following areas:

- ***Site Control & Permitting*:** identified potential risks associated with the land and permitting attributes.

- ***Environmental*:** identified and documented any federal, state and local environmental constraints associated with, for example, wildlife, air quality, National Environmental Protection Act ("NEPA") requirements, Federal Aviation Administration ("FAA") restrictions, and historic/archeological resources (including impacts on cultural resources).[57]

- ***Technical Review and Ongoing Expenditures*:** identified and documented potential risks of technologies and validated ongoing expenditures. For bids proposing Company ownership, O&M and ongoing capital expenditures ("capex") estimates were developed.

- ***Finance, Credit, Legal and Tax*:** reviewed PPAs and BOT term sheets for acceptability, including security terms, timelines/schedules, contract provisions and liability. This team also analyzed the credit worthiness, financial, tax (including expected qualification for various IRA tax incentives), and investment implications of each bid.

- ***Transmission:*** identify and document feasibility of the proposed transmission access plan. Validated generator interconnection costs and estimated transmission line losses.

<u>Advancement to Computer Modeling</u>

Following the initial eligibility screening and higher-level due diligence reviews, the Company determined the levelized cost of energy ("LEC") and levelized cost of capacity ("LCC") for each bid. These calculations included the assigned Transmission Interconnection costs determined by the Transmission Access department subject matter experts and followed the analytical process outlined in Volume 2, Technical Appendix, of the Company's Phase I filing.

The bids were ranked by LEC/LCC and grouped by technology type and ownership structure. The Company and the IE then jointly reviewed the sorted list and determined a cutline for each type/structure independently with the goal being to advance enough bids, and the most economic bids, that would be able to create a portfolio consisting

[57] Select bids with impacts on cultural resources were not advanced in the process. Bids were not set aside on this basis alone, but it was a key factor in evaluating whether or not certain bids advanced and ultimately were included in the portfolios presented in this Report.

solely of that technology and ownership structure. This resulted in a large number of bids advancing to computer modeling, but the Company and IE believed it was better to err on the side of inclusivity rather than risk artificially limiting options for portfolio development. Of the 1,073 bids submitted, 382 were advanced to computer modeling. The list of bids advanced is contained in Highly Confidential Appendix P.

Best In Class Testing

Following the advancement to computer-based modeling, and after the challenges described in Section 3 with the initial modeling were solved, the Company conducted the best in class computer evaluation described in Section 3.4. The results of this testing were reviewed with the IE, and all decisions were mutually agreed to. Additionally, the final due diligence review was completed around this time, and the final number of bids advancing into portfolio development was narrowed down to the top 166 bids.

Portfolio Development

After the best in class testing narrowed the bids down to the final candidates, due diligence was completed, and the reliability rubric was finalized, the Company began development of the final portfolios presented in this Report. This Section describes the portfolio development framework utilized by the Company during Phase II (see Appendix A for a Phase II EnCompass Model Run Matrix).

To develop the Reference Case and Preferred Portfolios, model runs were completed with only generic resource options in the expansion plan to generate the locked tails for 2031-2050 as described in the 'Development of Bid Portfolios' section of Volume 2, Technical Appendix, (page 332) filed in Phase I. This process was actually completed prior to the receipt of bids but is the first step in the overall modeling process. These tails were locked in for all Scenarios from 2031-2050. Separate runs and resulting tails were created for the Reference Cases (those that are not required to meet the Clean Energy targets and referenced as the “Reference Case generic tail”) and the other portfolios (those that are required to meet Clean Energy targets and referenced as “Clean Energy target generic tail”) thus creating two sets of locked tails. The generic resources that were added in the RAP in those runs were removed and the net accredited capacity need calibrated to exactly match the Load and Resources position filed with the Updated Modeling Assumptions document, thus creating a capacity deficit or “hole” in the model that the bids will fill. Following the development of the locked tails for 2031-2050, the portfolios were then optimized with bids from 2023-2028, and generics in 2029 and 2030.

The ***Reference Case*** portfolio (Scenario 0) was not specifically cited in the Updated Settlement Agreement modeling framework, but that portfolio is not required to achieve the 2030 clean energy target and includes “business as usual” actions on the Pawnee and Comanche 3 units (retire EOY 2041 and 2069 respectively). This portfolio is for comparison purposes/cost benchmark only and can be used to distinguish the set of resources necessary to meet customer needs without the additional requirement of 80% CO2 reduction by 2030. There was no assumed ownership constraint and utilized the Reference Case generic tail.

The ***Preferred Portfolio*** (Scenario 1) is the Company's Preferred Plan portfolio and is recommended for approval by the Commission as outlined within this Report. There is an assumed minimum 48% ownership target with no upper bound, and it utilized the generic tail built around meeting the clean energy target. This portfolio includes the three factors described in Section 2.5 to mitigate local reliability issues and provide environmental and Just Transition benefits. Once the Preferred Plan portfolio was developed, a derivative portfolio of the Preferred Plan was created to reflect the exclusion of the biomass resource, that is intended to meet the spirit of the ***Preferred Plan, Inverse of House Bill (HB) 21-1324 Resources*** (Scenario 2). Since the Preferred Plan scenario *selects* the biomass resource (at least conceptually) this scenario excluded the resource. Like the Preferred Plan, it assumed a minimum 48% ownership target with no upper bound and utilized the Clean Energy target generic tail.

The ***Least-cost Informational Portfolio*** (Scenario 3) utilized no ownership minimum in the EnCompass modeling. The purpose of this portfolio was to provide a benchmark for whether the preferred portfolio and the Company ownership included within it can be acquired at a "reasonable cost and rate impact," consistent with §40-2-125.5(5)(b), C.R.S. It assumed the Clean Energy target generic tail. To gain further insight regarding Company ownership targets, a ***40 percent ownership test portfolio with no upper constraint*** (Scenario 4) was performed which utilized a 40% ownership minimum constraint in the EnCompass modeling. It was observed during the development of the portfolios that the ownership reflected in the Least Cost Plan exceeded both the Preferred Plan's model input 48% ownership target, as well as a 40% minimum target. Since the ownership constraint was shown intuitively to be non-binding in that run, this particular portfolio was developed primarily to prove the constraint itself would not change bid selections when non-binding. This hypothesis was confirmed as the results of this portfolio are identical to the Least Cost Plan. Based on this evidence, it was determined that running additional versions of Scenario 4 (such as with $0CO2 and annuity tail representation) were not necessary, so long as the LCP result for those variants also demonstrated non-binding ownership levels. The ownership target was set to a minimum 40% with no upper bound, and the Clean Energy target generic tail. Another portfolio that was determined to not have a binding constraint was the ***Accelerated CO2 Reduction Portfolio***, since the carbon reductions reflected in the Preferred Plan are greater than the required 75 percent reduction set forth in the Updated Settlement Agreement. This hypothesis was confirmed as the results of this portfolio are identical to the Preferred Plan.

The next portfolio described in the Updated Settlement Agreement and created during this Phase II evaluation was the ***Lower Flexible and Fully Dispatchable Alternate Portfolio*** (Scenario 6). This portfolio was developed limiting the nameplate capacity level of flexible and fully dispatchable generation to the level in the Preferred Plan portfolio less 20 percent. A minimum 48% ownership target with no upper bound was assumed, and this portfolio was based on the Preferred Plan portfolio including the reliability and Just Transition considerations.

Another portfolio comprised as much as possible of bids that propose the use of a PLA, modeled as ***High PLA Portfolio (07_High PLA)***, which assumed a minimum 48% ownership target with no upper bound and assumed the Clean Energy target generic tail. This portfolio was developed by excluding bids with BVEM scores less than 50%, requiring technology-specific capacity minimums from the Preferred Plan portfolio, and keeping the same local reliability and Just Transition actions as the Preferred Plan portfolio.

The ***No New Natural Gas Build Portfolio*** (Scenario 8) was developed by the Company for feasibility and relied solely on life extension proposals and PPA extension gas proposals to the extent gas is selected as part of the portfolio, with new natural gas proposals excluded in the construction of the portfolio. In addition to this required portfolio, the Company also developed a demonstrative portfolio where no gas at all was allowed to be selected. The results of this demonstrative portfolio are described in Section 2, while the results of the Scenario 8 as described in the Updated Settlement Agreement are presented in Section 4.

Similar to the Inverse HB21-1324 Portfolio 2, the ***May Valley-Longhorn Extension Portfolio*** (Scenario 11) portfolio is designed to test the opposite decision regarding the MVLE as what appears in the Preferred Plan. Since MVLE was selected in the Preferred Plan, this scenario must exclude the bids that utilize the MVLE and the costs of the transmission line. This portfolio was to execute a cost and benefit analysis for the MVLE in accordance with the terms of the Settlement Agreement in Proceeding No. 21A-0096E. It includes the same local reliability and Just Transition actions as the Preferred Plan and the same 48% ownership target and Clean Energy target generic tail.

To evaluate the five Section 123 resources in the bid pool, including the biomass unit, the ***Section 123 Resources*** **(Portfolio 12, A-E)** portfolios were developed. Per the Commission Phase I decision, Option A was applied in which Section 123 bids are forwarded to EnCompass modeling for full portfolio re-optimization around the locked in Section 123 resource. The results for these evaluations are presented in Section 7. An additional evaluation for the biomass unit that comports with Option A is also presented there, although the Company believes the with/without analysis presented in Section 2 is the most appropriate way to evaluate this resource.

A few portfolios were ultimately not performed based on certain triggers for inclusion of these “conditional” portfolios[58] not being met. Specifically, the ***Midpoint Ownership*** and ***Front-Load or ISD Sequence Portfolios*** were not performed during Phase II. As set forth in the Updated Settlement Agreement, the Midpoint Ownership portfolio was not applicable due to the ownership percentage of the Least-Cost Informational Portfolio. Due to the passage of the IRA and the qualification time period of tax credits exceeding the RAP the Front-Load or in-service date (“ISD”) Sequence Portfolios were not applicable in this evaluation. In addition, some optional or alternative portfolios were developed, specifically versions of the Reference Case, Preferred Plan, and Least-Cost Plans reflecting a prospective new load.

Finally, the ***Backup Bid Portfolio Pools*** were developed as discussed and presented in Section 2. The Company removed all bids of a particular type from the Preferred Plan, to find the “next in line” pool of bids for that type.

Following the development of the capacity expansion plans, the Company performed several sensitivities either as (1) a reoptimized expansion plan run plus production costing run, (2) a reprice of the production costing run, or (3) no EnCompass run and simply an out of model adjustment. Results of these sensitivities and production cost scenarios are provided in Section 4 and in Appendix U.

3.7 Modeling Process and Steps Summary

When developing each of the portfolios described above, the Company followed a sequential process that is captured in the reliability rubric. The rubric process followed three key steps as generally described below and shown in the rubric provided as Appendix E.

- EnCompass Base Run – The model was run using only the base assumptions, with no reliability additions presumed. The results from this initial run were tested under the hot summer/cold winter tests.

- EnCompass Reliability Testing – the left side of the rubric was iteratively solved in EnCompass until the portfolio passed the hot summer/cold winter scenarios and was then passed to Plexos ELCC testing.

- Plexos Reliability Testing – The portfolio that passed EnCompass was then checked in Plexos for meeting the required PRM. If the portfolio did not, the right side of the rubric was iteratively solved until the PRM was met, with the final scenario also being tested again for the summer/winter scenarios to ensure the final portfolio met all criteria.

[58] As set forth in the Settlement Agreement

3.8 Commercial Operations Reliability Analysis

In addition to these modeling steps, the Company's Commercial Operations team also reviewed the portfolios, primarily the Preferred Plan, to ensure that the hourly model results were realistically representing results that were achievable in real time operations and to identify other reliability or operational issues not necessarily captured by the modeling.

Deliverability of Generation and Reserves to Denver Metro Load

Commercial Operations evaluated the deliverability of energy and reserves in the Preferred Plan. The CPP provides transmission access to significant volumes of renewable generation and delivers that generation to three substations at the gateway to the Denver metro area load. Since Phase I of the current ERP, Commercial Operations has become aware that there are limits to the aggregated flow of generation through these gateway substations and subsequently into the Denver metro Area—heretofore called the Denver metro constraint. This issue is discussed in more detail in Section 6. Most of the capacity and energy resource additions in the Preferred Plan are connected to the CPP and will potentially be limited by the Denver metro constraint.

Commercial Operations re-evaluated cold winter and hot summer weather scenarios with the Denver metro constraint in place. This divides resources into Metro-side resources and CPP-side resources; imports from the latter limited, in aggregate, by the Denver metro constraint. Most resources are located on the CPP-side of the constraint. Metro-side renewable resources are dominated by behind-the-meter ("BTM") and community solar garden ("CSG") generation. Metro-side thermal resources are dominated by large combined-cycle ("CC") facilities (i.e., Cherokee, Rocky Mountain Energy Center).

Commercial Operations identified a reliability concern during summer peak conditions during evening hours (6-9pm). The Metro-side renewable fleet is in steep decline or zero in these hours requiring load to be served by other Metro-side assets and with power transferred across the Denver metro constraint. At today's transfer levels, there would not be enough deliverability to maintain reliable energy and reserves. This is exacerbated with modest outages of Metro-side resources, thereby making the system more reliant on transfers across the constraint.

When Metro-side resources are unavailable, either from lack of solar or thermal forced outages, the CPP-side resources would need to make up the difference and need to be deliverable to the Denver metro load. This result was communicated to Transmission Planning and informs their planned expansion of the Denver metro area transmission network to ensure deliverability of resources outside the Denver metro area to serve load during the concerning 6-9pm summer period.

Increased Variability in Solar Generation Under Preferred Plan

An increase in regulating reserves will be required to mitigate solar variability as a result of the Preferred Plan due to the current and increasing concentration of solar in or near Pueblo. Battery energy storage systems ("BESS") will be able to serve this need eventually, but the installation of BESS lags the installation of solar generation during the RAP. An increase in regulating reserves was expected due to an increase in solar generation, but the concentration near Pueblo has increased (and will continue to increase) the need more than expected.

The recent additions of Neptune and Thunder Wolf solar generation has contributed to significant solar ramp events associated with cloud cover in the Pueblo area. Commercial Operations used the latitude and longitude for new solar generation in the Preferred Plan to pull corresponding historic, location specific irradiance data from the NREL National Solar Radiation Database to create realistic generation profiles on a 5-minute basis. Commercial Operations then calculated the growth of the largest 10-minute and 30-minute loss of solar generation ramps as the solar portfolio grows over the RAP. The responsive capacity from BESS over the RAP was matched with ramping need. The result shows non-BESS resources must be available for fast-ramping service until mid-2027. Thereafter, BESS capacity may be sufficient to mitigate the worst ramps caused by solar variability due to cloud cover over the Pueblo area. Ultimately the flex and/or regulating reserve requirements may need to be updated to account for the increased risk of coordinated up and down ramps of large amounts of solar in close proximity. The need for increased reserves will be studied, quantified, and presented in the 2024 Pueblo Just Transition Plan filing.

Limitations of Computer Modeling Compared to Real Time Operations

The EnCompass model provides valuable information on the projected costs and operations of the system; however, it is important to note that these are modeled results and are projecting years into the future. In addition to all of the normal variance in forecasting, the modeling process itself can lead to structural optimism in operational performance, such as carbon reduction potential and expected curtailments. The model has perfect foresight into all the operating parameters of the system,[59] and develops a perfect commitment and dispatch decision based on this perfect foresight. This also extends to battery charging and deployment decisions. As an example, the model knows exactly when renewable generation will fall or a unit will experience an outage and will bring other generation online or ensure storage is fully charged in anticipation of that event at exactly the right time. Although our Commercial Operations team is constantly improving their ability to manage this increasingly complex system, they will

[59] The model has perfect foresight into items such as exact hourly load, exact hourly renewable generation output, upcoming "unplanned" outages, etc. and can plan the perfect setup, even many days in advance, to serve load in the single most reliable and economic manner possible.

never have the perfect foresight needed to mimic these perfect operational decisions, which leads to more inefficient operations in reality than a perfect model would predict. While the operators, and the systems they use, make the best decisions possible based on the information available at the time, it will differ from the modeled results.

Additionally, the model makes some simplifying assumptions in the dispatch that do not fully capture all of the operational parameters of the generating units on the system. As an example, the model does not simulate start up cycles when units are turned on and ramping up to the minimum load necessary to be synced to the grid, and simply shows them going from offline to minimum loading instantaneously. These startup cycles consume fuel (which is captured) but also emit carbon (which is not captured).

The model is also developing forecasts based on typical, or expected value, forecasts for items such as load and renewable energy production. As with any expected value, there is an equal probability of the variables being higher or lower than modeled, leading to normal, expected, and guaranteed deviation from the modeled values. It is impossible to know where 2030, or any other year, will fall on this distribution.

Despite these qualifications, the model is useful for determining a baseline from which to develop an expectation for operations. However, it is important to realize that real time operations will not be as efficient as predicted by models, and accordingly carbon emissions and curtailments will differ from the predicted results.

<u>Curtailment</u>

Curtailment is the deliberate reduction in (typically weather-dependent renewable) generation levels to maintain the balance of generation to current load, or to maintain a safe and reliable transmission system. As the Company's system evolves to incorporate larger amounts of such generation, curtailment becomes an even more critical tool to maintain energy balance or to respond to transmission events or congestion or possibly provide for ancillary services.

The Commercial Operations team utilizes advanced forecasting and grid management tools to operate the system in the most economic manner possible, while maintaining reliability of both the generation and transmission systems. A natural byproduct of these actions is an effort to manage curtailments optimally, that is to use curtailment as a tool in the most economic manner possible. Typically renewable energy is curtailed after other more economic options to restore system power balance or manage transmission congestion have been exhausted, including redispatch of thermal resources, storage of renewable energy, or sales of excess renewables off the system.

Specifically regarding curtailments, the EnCompass model is a significant step forward from historically used models in the ability to forecast curtailments, and with the enhancements made to the model since the conclusion of Phase I, that ability has increased dramatically. However, the model still has limitations both in the types of curtailment it captures, as well as the overall level of curtailment for the types it does capture.

Realistically, the model primarily captures what is called “bottoming” curtailments, i.e., curtailment associated with excess generation above the hourly load obligation.[60] With the added modeling enhancements recognizing the curtailment costs associated with compensation for lost tax credits now in place, the model is able to determine the optimal level of overall curtailment, as well as which resources would be curtailed, much more effectively. However, the model still has limitations that make the forecast results more a “best possible case scenario” than a realistic expectation of what would occur in real time operations.

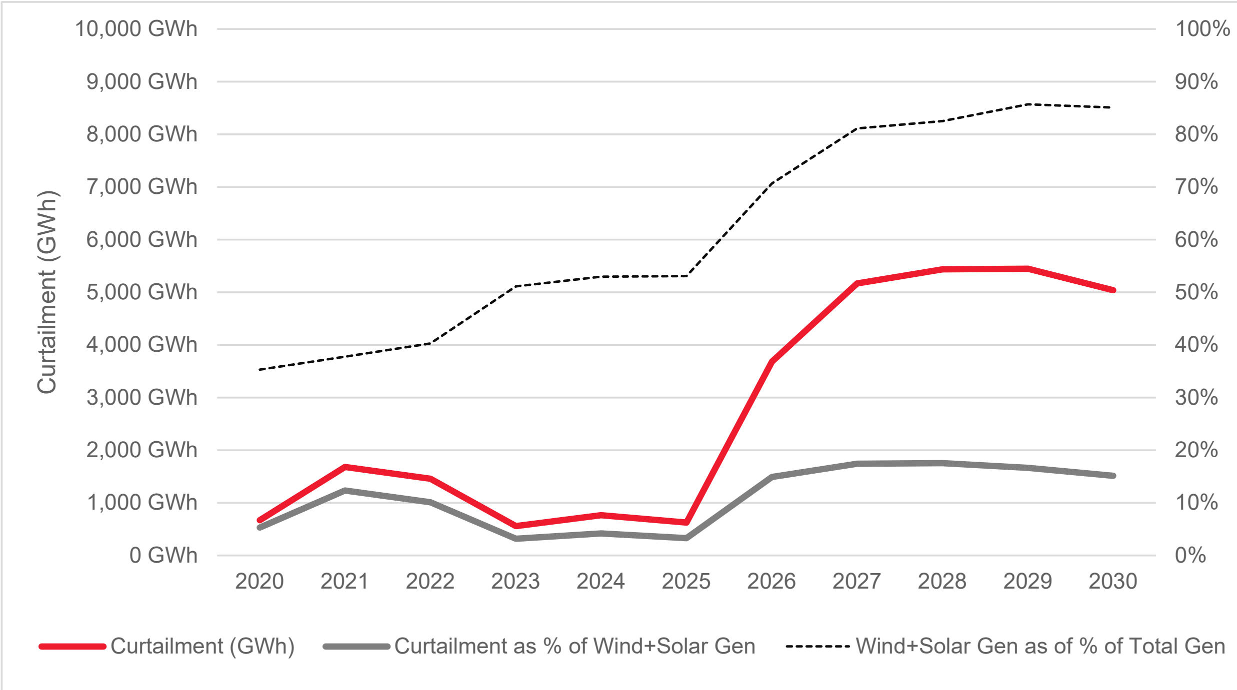
Additionally, a large percentage of curtailment is the result of real time perturbations in the system that are not captured in the model, such as transmission line outages and orders from the transmission system operator to run units out of economic order (i.e. “must run” a unit that would otherwise be offline) to solve local congestion or reliability events.

One final limitation is in the solution logic of the model itself. The Company uses the “simplified commitment” logic in EnCompass to complete production costing runs, which relaxes some operational constraints to both solve faster and provide more of an “expected value” or median result over a long study period. The primary simplification is relaxing the minimum loading levels for generators at the hourly level, which means in a certain hour a unit (primarily thermal) might be running at a level below the actual physical limitations of the unit. In real time, this unit might be running at a higher level (its minimum loading) which would tend to increase potential curtailments accrued. Conversely, it might be offline, thereby reducing curtailment, but this modeling construct would most likely tend towards under-forecasting curtailment over the long haul.

With the substantial increase in the amount of weather dependent generation being added to the system in the Preferred Plan, it would be naturally expected that curtailment would increase as well. However, largely due to the beneficial impact of the large amount of existing and planned storage on the system, curtailments are expected to be maintained at manageable levels, as shown in the figure below of the modeled curtailments from the Preferred Plan. It is important to note that the EnCompass model took into consideration the cost impacts of curtailment, and the resulting balance of additional renewable generation and associated curtailment was the optimal economic balance determined by the model.

[60] Load would include available charging load for storage such as batteries or pumped hydro that is not currently fully charged.

Figure 19 – Modeled Curtailments in the Preferred Plan



4.0 Additional Phase II Portfolios

This Section 4.0 provides an overview of the suite of bid portfolios developed to comply with Attachment 1 of the approved Updated Settlement Agreement and other Commission directives in the Phase I Decision. This Section provides an overview of the portfolios not previously discussed, which were developed to meet the required portfolios outlined in Paragraph 14 and Attachment 1 of the Updated Settlement Agreement (as well as the ERP "business as usual" portfolio consistent with the Phase I Decision).[61] See Appendix A for a Phase II EnCompass Model Run Matrix.

To assess how changes to key modeling assumptions impact the costs and benefits of bid portfolios, a range of sensitivities were evaluated by the Company as part of the bid evaluation process as required by the terms of the Updated Settlement Agreement and other Commission directives from the Phase I Decision. Sensitivities typically involve repricing the various bid portfolios developed under base case assumptions by varying a single base assumption such as future gas prices. These types of sensitivities do not result in changes to the timing or mix of bids in a portfolio. Other sensitivities, such as alternatives where the underlying load forecast is changed, require both the creation of a new portfolio to match the changed load as well as the production costing run to determine costs and operational characteristics. Results from these sensitivities are presented in this Section and in Appendix U and Appendix V.

Each portfolio presented in this Report was developed using two alternative views of the cost impact of carbon emissions. One view utilizes the SCC[62] in accordance with statutory specifications in the capacity expansion phase of the modeling. This selects resources and portfolio size inclusive of the societal impacts of carbon emissions. This cost was removed in the production cost modeling of the final portfolios. The costs for these SCC portfolios are presented throughout the document and appendices without including costs for carbon (labeled "PVRR") and also with adding the social costs of both carbon and methane determining post modeling by multiplying the carbon and methane emissions by the appropriate social costs. These results with the social costs of emissions included are labeled "PVSC."

Additional information as to the specific bids/projects contained within each of these portfolios and the characteristics of those portfolios can be found in Appendix S and Appendix T. Moreover, the Phase I Decision provides that "Public Service shall clearly delineate in each optimized portfolio the various categories of costs and savings set forth in the statute. Public Service must also do this for the Phase II ERP portfolio."[63]

[61] Decision No. C22-0459, at ¶ 331.
[62] The values for the social cost of carbon are included in the Modeling Assumptions Update provided as Appendix D.
[63] Phase I Decision, at ¶ 320.

The Company interprets this as requiring data to show net present value revenue requirements ("NPVRRs") for each presented portfolio and savings (e.g., the fuel-related savings as set forth in Section 2.8 for the Preferred Plan), and this data is captured in the respective appendices supporting the portfolios.

Reference Case

Primarily created to have a baseline cost comparison for regulatory and ratemaking purposes, the Company created several versions of a Reference Case. These Reference Cases, numbered as Portfolio 0, do not include the approved coal actions from Phase I regarding Pawnee and Comanche 3, and are also not required to meet the clean energy targets. Reference Cases were created for both the SCC and $0CO2 views, as well as special purpose Reference Cases that included the prospective new load. These prospective new load Reference Cases are to support development of a record for possible Commission approval of the Prospective New Load Scenario and provide a consistent cost comparison to the Preferred Plan that includes the additional load. The portfolio details and annual costs of these portfolios are contained in the appendices (Highly Confidential Appendices S and T),[64] but a summary comparison of the Preferred Plan (SCC) and the Reference Case (SCC) is shown below in Table 22. A comparison of these portfolios without carbon costs, Preferred Plan ($0C02) and Reference Case ($0C02) is shown in Table 23.

[64] Consistent with Paragraph 211 of the Phase I Decision, Appendix W provides executable annual nominal cash flows associated with each portfolio presented in this Report.

Table 22 - SCC Preferred Plan and Reference Case Comparison

Portfolios' Comparison of Key Characteristics

	1 - Preferred Plan (SCC)	0 - Reference Case Plan (SCC)
Nameplate Capacity (MW)		
Biomass	19	-
Gas	628	619
Solar	1,969	2,169
Storage	1,170	1,420
Wind	3,406	2,906
TOTAL Nameplate Additions (MW)	7,192	7,114
Flexible Capacity (MW)	1,817	2,039
Colorado Power Pathway (CPP) Trx Utilization (MW)	4,411	4,361
CPP May Valley-Longhorn Extension Trx Utilization (MW)	1,206	1,206
Accredited Capacity (MW)	1,621	1,633
Section 123 Capacity (MW)	19	-
Owned Capacity (MW)	4,787	4,540
Owned Capacity (%)	66.6%	63.8%
Owned Energy (%)	69.7%	74.7%
Accredited Capacity Position		
2028 Capacity Position Long/(Short) (MW)	100	112
2028 Actual Reserve Margin (%)	19.7%	19.9%
Planning Period Present Value Revenue Requirement (PVRR) ($M)		
NPV Base Portfolio Costs ($M)	$ 41,708	$ 41,531
NPV Trx PO-PF Interconnection Costs ($M)	$ 130	$ 127
NPV Trx Network Upgrades for Delivery ($M)	$ 2,353	$ 2,353
TOTAL PVRR ($M)	$ 44,191	$ 44,011
PVRR Delta vs. Preferred Plan ($M)	$ -	$ (180)
Emissions		
2023-2030 CO2 (M Tons)	69,322,272	85,864,922
2023-2055 CO2 (M Tons)	93,063,889	165,308,267
2023-2055 CO2 Delta vs. Preferred Plan (M Tons)	-	72,244,378
2030 CO2 Reduction from 2005 (%)	-87.4%	-74.8%
2023-2055 NPV CO2 at SCC ($M)	$ 6,288	$ 10,370
2023-2055 NPV Methane at SCM ($M)	$ 57	$ 35
TOTAL Present Value Societal Cost (PVSC) ($M)	$ 50,535	$ 54,415
PVSC Delta vs. Preferred Plan ($M)	$ -	$ 3,880
Other		
2023-2055 Natural Gas Burn (MMBtu)	648,263,108	401,216,266
2028 Renewable Energy MWh (%)	83.0%	77.5%

Table 23 - 0CO_2$ Cost Preferred Plan and Reference Case Comparison

Portfolios' Comparison of Key Characteristics

Nameplate Capacity (MW)	1 - Preferred Plan ($0CO2)	0 - Reference Case Plan ($0CO2)
Biomass	19	-
Gas	669	800
Solar	1,619	1,084
Storage	1,848	1,420
Wind	1,700	1,700
TOTAL Nameplate Additions (MW)	5,854	5,004
Flexible Capacity (MW)	2,535	2,220
Colorado Power Pathway (CPP) Trx Utilization (MW)	2,933	2,905
CPP May Valley-Longhorn Extension Trx Utilization (MW)	-	-
Accredited Capacity (MW)	1,580	1,567
Section 123 Capacity (MW)	68	-
Owned Capacity (MW)	3,152	3,149
Owned Capacity (%)	53.8%	62.9%
Owned Energy (%)	67.7%	68.7%
Accredited Capacity Position		
2028 Capacity Position Long/(Short) (MW)	59	45
2028 Actual Reserve Margin (%)	19.1%	18.9%
Planning Period Present Value Revenue Requirement (PVRR) ($M)		
NPV Base Portfolio Costs ($M)	$ 42,249	$ 41,339
NPV Trx PO-PF Interconnection Costs ($M)	$ 96	$ 82
NPV Trx Network Upgrades for Delivery ($M)	$ 1,972	$ 1,841
TOTAL PVRR ($M)	$ 44,317	$ 43,262
PVRR Delta vs. Preferred Plan ($M)	$ -	$ (1,055)
Emissions		
2023-2030 CO2 (M Tons)	73,516,151	92,644,556
2023-2055 CO2 (M Tons)	103,173,800	183,711,272
2023-2055 CO2 Delta vs. Preferred Plan (M Tons)	-	80,537,472
2030 CO2 Reduction from 2005 (%)	-85.1%	-69.0%
2023-2055 NPV CO2 at SCC ($M)	$ 6,895	$ 11,462
2023-2055 NPV Methane at SCM ($M)	$ 69	$ 46
TOTAL Present Value Societal Cost (PVSC) ($M)	$ 51,280	$ 54,769
PVSC Delta vs. Preferred Plan ($M)	$ -	$ 3,489
Other		
2023-2055 Natural Gas Burn (MMBtu)	786,871,016	528,147,603
2028 Renewable Energy MWh (%)	77.6%	69.1%

Informational Least Cost Plan

This informational portfolio utilizes no ownership minimum in the EnCompass modeling. The purpose of this portfolio is to provide a benchmark for whether the Preferred Plan and the Company ownership included within it can be acquired at a “reasonable cost and rate impact,” consistent with § 40-2-125.5(5)(b), C.R.S. This portfolio includes a minimum of an 80 percent emission reduction by 2030 from 2005 levels. This portfolio is the lowest cost portfolio and serves as the prerequisite for the 40% Ownership (Portfolio 4), Midpoint Ownership (Portfolio 5), and the portfolio that satisfies extreme summer needs. In comparison with the Preferred Plan development, the informational Least Cost Plan does not meet the strategic and essential Alamosa reliability needs, Transmission support, nor address Just Transition considerations by omitting the inclusion of Bid 0986, Bid 0989, and the Hayden Biomass project, respectively. As this portfolio was created with the least amount of constraints within EnCompass, it serves as an informational comparison against the other portfolios. The portfolio details and annual costs are contained in Highly Confidential Appendices S, T, and U, but an illustrative comparison of the Preferred Plan (SCC) and the Least-Cost Portfolio (SCC) was previously provided in Table 6.

40 Percent Ownership Test Portfolio with No Upper Constraint

One of the derivate portfolios of the informational Least Cost Plan was the 40 Percent Ownership Test Portfolio with No Upper Constraint. This portfolio utilized a 40 percent ownership minimum constraint in the EnCompass modeling, with the purpose being to provide a benchmark and test for whether the Preferred Plan and the Company ownership included within it can be acquired at a “reasonable cost and rate impact,” consistent with § 40-2-125.5(5)(b), C.R.S. However, the Least Cost Plan (SCC) resulted in 58.1% capacity ownership, exceeding a 40 percent minimum target without an ownership constraint being applied. Therefore, it can be assumed that imposing minimum 40% ownership will not be binding and will not result in a different bid portfolio. But to verify this intuition, the minimum 40% ownership constraint was applied as the only additional constraint as compared to the informational Least Cost Plan and an additional model run was performed. The result was identical bids selected as in the Least Cost Plan, verifying the ownership constraint was non-binding.

Midpoint Ownership Portfolio

As part of the Updated Settlement Agreement, the Company planned to provide an additional portfolio if the midpoint between the level of ownership in the statute (i.e., 50 percent) and the informational Least Cost Plan was more than five (5) percentage points greater or less than the 40 percent Portfolio. The modeled ownership minimum for purposes of this portfolio was to be the midpoint of the difference between the statutory ownership target and the informational Least Cost Plan. However, if the informational Least Cost Plan contained more than 50 percent ownership, then the Company was not to provide this Midpoint Ownership Portfolio as part of this Report.

Because the 40 percent ownership constraint was not binding, this portfolio is no longer applicable as set forth in the Updated Settlement Agreement.

Extreme Weather Portfolio

The Extreme Summer Portfolio is meant to demonstrate a portfolio that satisfies the 2028 summer operational reliability requirements of the “Extreme Summer” sensitivity. The capacity by technology type determined in the informational Least Cost Plan was used as the minimum starting point for this portfolio since the informational Least Cost Plan portfolio meets the reliability requirements described in detail in Section 2, and an additional 200 MW of gas-fired resources and 200 MW of storage resources were required to be added to this portfolio to ensure no violations are reflected in the July 2028 modeling test year. An illustrative comparison of the Least Cost Plan (SCC) and the informational Least Cost Plan (SCC) - Extreme Weather is provided below, which reflects a higher resulting 2028 reserve margin of 24.2% for this portfolio.

Table 24 - Least Cost Plan (SCC) and Least Cost Plan (SCC) – Extreme Weather Comparison

Portfolios' Comparison of Key Characteristics

Nameplate Capacity (MW)		3 - Least Cost Plan (SCC)		3 - Least Cost Plan (SCC) - Extreme Weather
Biomass		-		-
Gas		619		819
Solar		2,369		2,369
Storage		1,420		1,620
Wind		3,406		3,406
TOTAL Nameplate Additions (MW)		7,814		8,214
Flexible Capacity (MW)		2,039		2,439
Colorado Power Pathway (CPP) Trx Utilization (MW)		4,861		4,861
CPP May Valley-Longhorn Extension Trx Utilization (MW)		1,206		1,206
Accredited Capacity (MW)		1,673		1,908
Section 123 Capacity (MW)		-		-
Owned Capacity (MW)		4,540		4,940
Owned Capacity (%)		58.1%		60.1%
Owned Energy (%)		65.7%		65.9%
Accredited Capacity Position				
2028 Capacity Position Long/(Short) (MW)		152		387
2028 Actual Reserve Margin (%)		20.5%		24.2%
Planning Period Present Value Revenue Requirement (PVRR) ($M)				
NPV Base Portfolio Costs ($M)	$	41,497	$	41,940
NPV Trx PO-PF Interconnection Costs ($M)	$	135	$	138
NPV Trx Network Upgrades for Delivery ($M)	$	2,353	$	2,353
TOTAL PVRR ($M)	$	43,984	$	44,431
PVRR Delta vs. Least Cost Plan ($M)	$	-	$	447
Emissions				
2023-2030 CO2 (M Tons)		68,822,125		68,624,386
2023-2055 CO2 (M Tons)		90,731,893		90,045,317
2023-2055 CO2 Delta vs. Least Cost Plan (M Tons)		-		(686,576)
2030 CO2 Reduction from 2005 (%)		-88.1%		-88.3%
2023-2055 NPV CO2 at SCC ($M)	$	6,160	$	6,121
2023-2055 NPV Methane at SCM ($M)	$	54	$	53
TOTAL Present Value Societal Cost (PVSC) ($M)	$	50,197	$	50,605
PVSC Delta vs. Least Cost Plan ($M)	$	-	$	408
Other				
2023-2055 Natural Gas Burn (MMBtu)		611,327,790		599,454,737
2028 Renewable Energy MWh (%)		83.7%		84.1%

Lower Gas Portfolios

In these portfolios, the Company imposed restrictions on the gas thermal resources that the EnCompass model was able to select to meet the needs of the RAP. Both portfolios were still subject to the summer/winter and PRM reliability tests in EnCompass and Plexos, respectively. For this reason, both portfolios were a feasibility study on how many renewable and energy limited resources would need to be acquired to cover the loss of firm dispatchable generation caused by upcoming retirements as well as fill the needs of the growing system. Table 25 below provides a side-by-side comparison of both portfolios and the informational Least Cost Plan.

<u>No Gas Build Portfolio</u>

The more restrictive portfolio of the two, this case prohibits the selection of any natural gas resources through 2030. In order to pass all reliability tests, this portfolio needed to add 13,025 MW of nameplate resources. For reference, this is more than doubling the amount of renewable and energy limited resources existing on the Public Service system at the start 2023. In comparison to the informational Least Cost Plan, the No Gas Plan added 534 MW of more solar, 2,279 MW of more storage, and 3,017 MW of more wind resources. The PVRR for the No Gas Plan is approximately $5.6 billion more than the PVRR of the Least Cost Plan with a corresponding increase to the rate impact for this portfolio.

<u>No New Natural Gas Build Portfolio</u>

In the No New Gas Build Plan, EnCompass was only restricted from selecting any new gas resources, meaning it was able to add bids that were PPA extensions or already existing gas resources bid into the RFP. In total, that meant that the model had approximately 253 MW of gas available to select to fill capacity needs. Table 25 below shows that while the number of resources needed to solve reliability constraints was less than the No Gas Portfolio, there was still a significant amount of resources needed. In total, 10,955 MW of nameplate resources were added, amounting to 559 MW of more solar, 2,316 MW of more storage, and 632 MW of more wind resources than the informational Least Cost Plan. The PVRR was also $3.2 billion greater than the PVRR of the Least Cost Plan.

The Company recognizes that the results of these two portfolios provide valuable insight into meeting the needs of the future Public Service system while striving to reach our clean energy goals with the existing technology available. Further penetration of similar technology types causes a significant decrease in capacity credit attributed to renewable and energy limited resources and a significant increase in the amount of added resources required to continue to serve our customers and maintain reliability. Considering that these cases have 4,225 MW of gas thermal capacity in 2028 which will continue to decrease in future years, these results highlight the need for further advancements in technology and a more diverse portfolio of resources may be needed to help economically reach our clean energy goals in the future.

Table 25 - Least Cost Plan (SCC), No Gas Plan (SCC), and No New Gas Plano (SCC) Comparison

Portfolios' Comparison of Key Characteristics

Nameplate Capacity (MW)	3 - Least Cost Plan (SCC)	8 - No Gas Plan (SCC)	8 - No New Gas Plan (SCC)
Biomass	-	-	-
Gas	619	-	253
Solar	2,369	2,903	2,928
Storage	1,420	3,699	3,736
Wind	3,406	6,423	4,038
TOTAL Nameplate Additions (MW)	7,814	13,025	10,955
Flexible Capacity (MW)	2,039	3,699	3,989
Colorado Power Pathway (CPP) Trx Utilization (MW)	4,861	9,159	7,102
CPP May Valley-Longhorn Extension Trx Utilization (MW)	1,206	2,370	1,866
Accredited Capacity (MW)	1,673	1,531	1,559
Section 123 Capacity (MW)	-	-	-
Owned Capacity (MW)	4,540	6,269	5,587
Owned Capacity (%)	58.1%	48.1%	51.0%
Owned Energy (%)	65.7%	56.8%	66.1%
Accredited Capacity Position			
2028 Capacity Position Long/(Short) (MW)	152	9	37
2028 Actual Reserve Margin (%)	20.5%	18.3%	18.8%
Planning Period Present Value Revenue Requirement (PVRR) ($M)			
NPV Base Portfolio Costs ($M)	$ 41,497	$ 47,007	$ 44,633
NPV Trx PO-PF Interconnection Costs ($M)	$ 135	$ 223	$ 200
NPV Trx Network Upgrades for Delivery ($M)	$ 2,353	$ 2,353	$ 2,353
TOTAL PVRR ($M)	$ 43,984	$ 49,582	$ 47,186
PVRR Delta vs. Least Cost Plan ($M)	$ -	$ 5,598	$ 3,202
Emissions			
2023-2030 CO2 (M Tons)	68,822,125	62,282,423	64,700,021
2023-2055 CO2 (M Tons)	90,731,893	72,272,523	78,146,241
2023-2055 CO2 Delta vs. Least Cost Plan (M Tons)	-	(18,459,371)	(12,585,653)
2030 CO2 Reduction from 2005 (%)	-88.1%	-94.0%	-91.4%
2023-2055 NPV CO2 at SCC ($M)	$ 6,160	$ 5,104	$ 5,444
2023-2055 NPV Methane at SCM ($M)	$ 54	$ 34	$ 39
TOTAL Present Value Societal Cost (PVSC) ($M)	$ 50,197	$ 54,721	$ 52,669
PVSC Delta vs. Least Cost Plan ($M)	$ -	$ 4,523	$ 2,471
Other			
2023-2055 Natural Gas Burn (MMBtu)	611,327,790	369,977,093	428,542,897
2028 Renewable Energy MWh (%)	83.7%	93.0%	89.3%

Gas Price Sensitivities

High and low gas re-pricing sensitivities were run for the scenarios shown in Figure 20 through Figure 25 below. High and low gas price sensitivities adjust the annual growth rate up and down by 50 percent from the base gas price starting in year 2025 when the long-term fundamentals-based forecasts are blended with the market information. Costs presented in the tables below are the delta from the Preferred Plan.

Figure 20 – High Gas Price Scenario Compared to High Gas Price Preferred Plan SCC

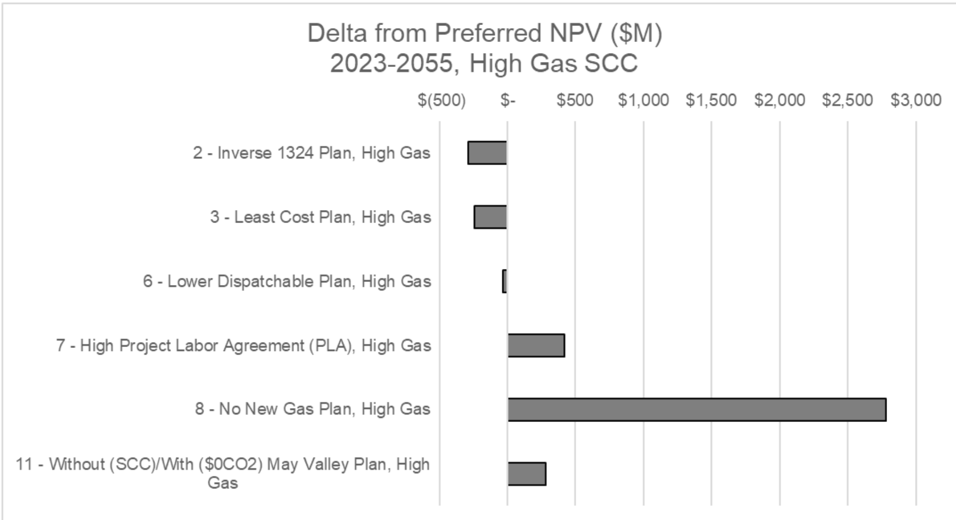


Figure 21 – Base Scenario Compared to Base Preferred Plan SCC

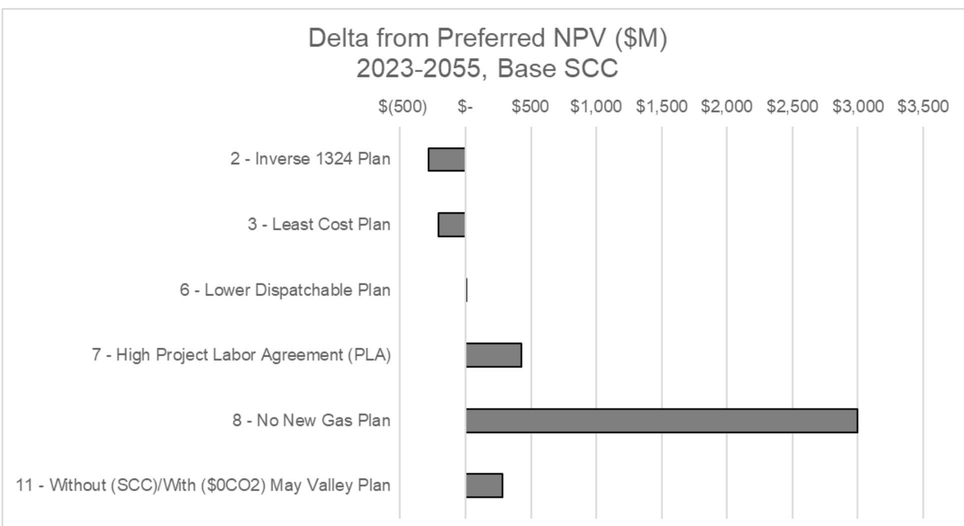


Figure 22 – Low Gas Price Scenario Compared to Low Gas Price Preferred Plan SCC

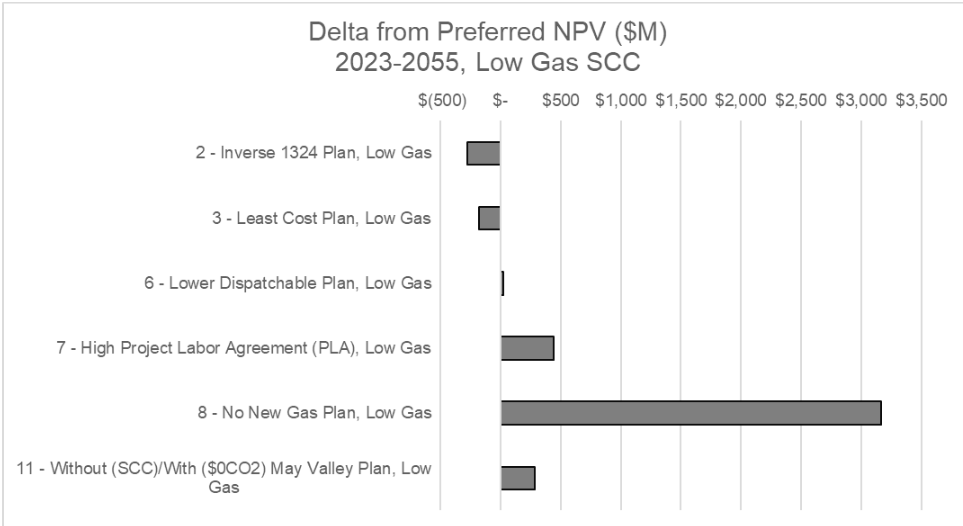


Figure 23 – High Gas Price Scenario Compared to High Gas Price Preferred Plan $0CO2

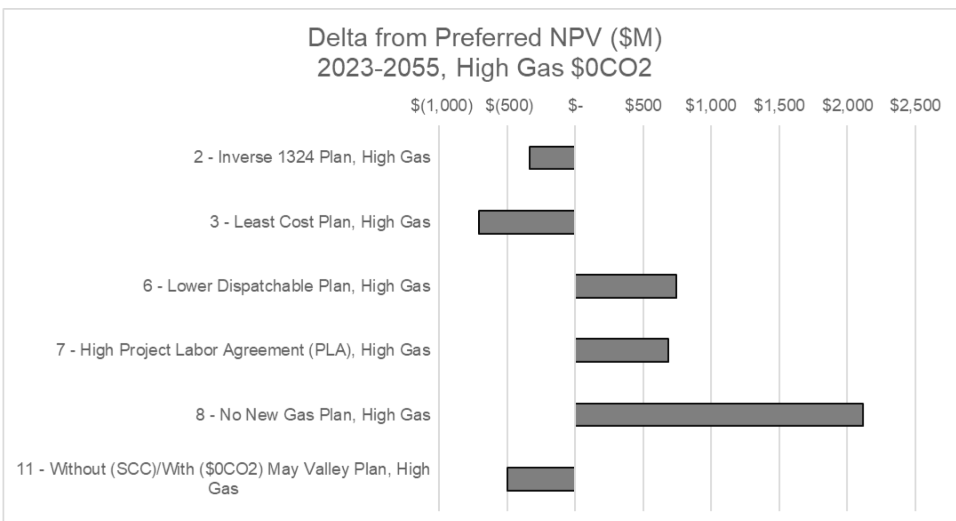


Figure 24 – Base Scenario Compared to Base Preferred Plan $0CO2

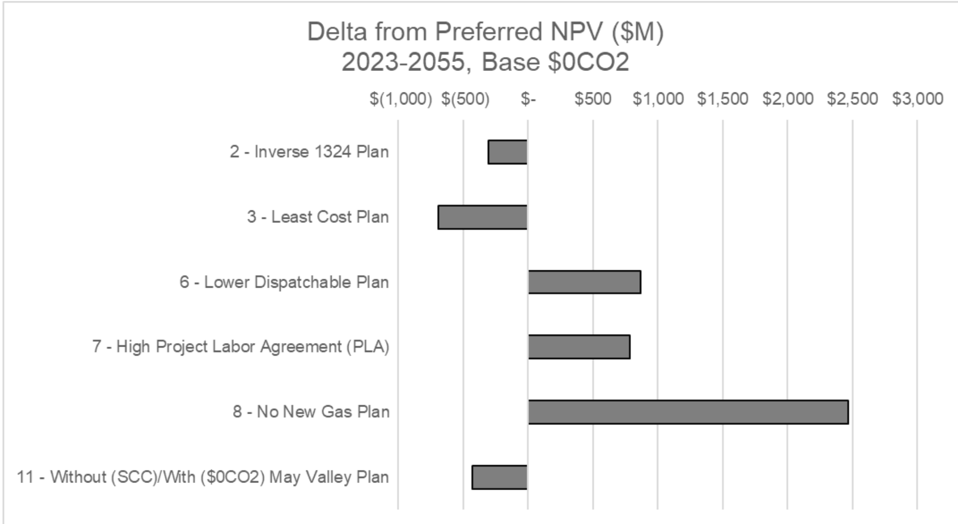
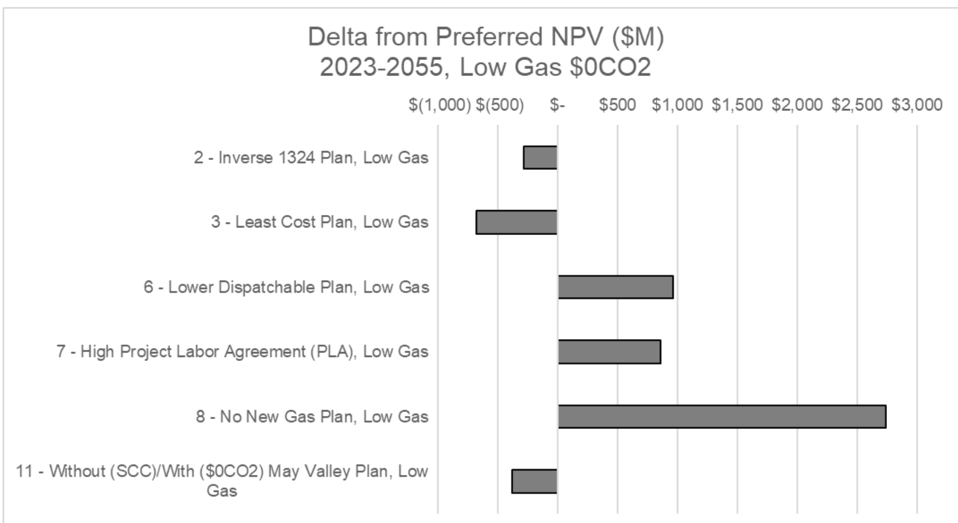


Figure 25 – Low Gas Price Scenario Compared to Low Gas Price Preferred Plan $0CO2



Load Sensitivities

The Preferred Plan Portfolio was reoptimized with four sensitivities of high load, low load, demand response and resource adequacy. Table 26 below provides a side-by-side comparison of the Preferred Plan and the Preferred Plan with the sensitives. The high and low load sensitivities are of the High (Roadmap) and Low forecasts.[65] The Roadmap scenario assumes a faster rate of electric vehicle ("EV") adoption and further beneficial electrification of space heating and water heating, based on the E3 study used to develop the State Greenhouse Gas Roadmap.[66]

As ordered in Paragraph 191 of Decision No. C22-0459, DR reoptimized sensitivity on the Preferred Plan assumes an increased amount of DR consistent with Staff's proposal of obtaining 25 MWs per year from 2023 through 2030 for a total of 200 MWs of additional DR.[67]

The Company has also modeled a sensitivity with the PPA extensions approved in Proceeding No. 23A-0046E unlocked. This sensitivity will provide additional information to the Commission and intervenors regarding the interaction of bids advanced to computer-based modeling and the resource mix the model selects to fill capacity in the near-term years of the RAP as compared to the short-term PPA resources approved in Proceeding No. 23A-0046E.

[65] Hrg. Exh. 109 (Goodenough Direct), p. 16:3-11; see also Hrg. Exh. 101 (Jackson Direct), Att. AKJ-2, Rev. 2, pp. 46-52 and 284-85.
[66] Phase I Decision, at ¶ 176.
[67] Phase I Decision, at ¶ 191.

Table 26 - Preferred Plan (SCC) and Sensitivities Comparison

Portfolios' Comparison of Key Characteristics

Nameplate Capacity (MW)		1 - Preferred Plan (SCC)		1 - Preferred Plan (SCC), High Load Sensitivity		1 - Preferred Plan (SCC), Low Load Sensitivity		1 - Preferred Plan (SCC), Demand Response Sensitivity		1 - Preferred Plan (SCC), Resource Adequacy Sensitivity
Biomass		19		19		19		19		22
Gas		628		704		428		628		704
Solar		1,969		2,869		1,969		2,169		2,369
Storage		1,170		1,170		1,170		1,170		1,170
Wind		3,406		3,406		3,504		3,406		3,435
TOTAL Nameplate Additions (MW)		7,192		8,167		7,090		7,392		7,700
Flexible Capacity (MW)		1,817		1,893		1,617		1,817		1,896
Colorado Power Pathway (CPP) Trx Utilization (MW)		4,411		5,311		4,509		4,611		4,811
CPP May Valley-Longhorn Extension Trx Utilization (MW)		1,206		1,206		1,202		1,206		1,206
Accredited Capacity (MW)		1,621		Not Modeled		Not Modeled		Not Modeled		Not Modeled
Section 123 Capacity (MW)		19		19		19		19		19
Owned Capacity (MW)		4,787		4,787		5,185		4,787		4,787
Owned Capacity (%)		66.6%		58.6%		73.1%		64.8%		62.2%
Owned Energy (%)		69.7%		61.8%		80.2%		68.0%		65.5%
Accredited Capacity Position										
2028 Capacity Position Long/(Short) (MW)		100		Not Modeled		Not Modeled		Not Modeled		Not Modeled
2028 Actual Reserve Margin (%)		19.7%		Not Modeled		Not Modeled		Not Modeled		Not Modeled
Planning Period Present Value Revenue Requirement (PVRR) ($M)										
NPV Base Portfolio Costs ($M)	$	41,708	$	44,027	$	42,830	$	41,719	$	41,858
NPV Trx PO-PF Interconnection Costs ($M)	$	130	$	157	$	126	$	133	$	157
NPV Trx Network Upgrades for Delivery ($M)	$	2,353	$	2,353	$	2,353	$	2,353	$	2,353
TOTAL PVRR ($M)	$	44,191	$	46,537	$	45,309	$	44,205	$	44,368
PVRR Delta vs. Preferred Plan ($M)	$	-	$	2,346	$	1,118	$	14	$	177
Emissions										
2023-2030 CO2 (M Tons)		69,322,272		71,549,760		67,594,248		69,174,308		68,633,425
2023-2055 CO2 (M Tons)		93,063,889		98,200,301		89,394,036		92,294,690		90,705,434
2023-2055 CO2 Delta vs. Preferred Plan (M Tons)		-		5,136,412		(3,669,853)		(769,199)		(2,358,455)
2030 CO2 Reduction from 2005 (%)		-87.4%		-86.4%		-88.8%		-87.6%		-87.9%
2023-2055 NPV CO2 at SCC ($M)	$	6,288	$	6,585	$	6,068	$	6,246	$	6,155
2023-2055 NPV Methane at SCM ($M)	$	57	$	63	$	53	$	56	$	54
TOTAL Present Value Societal Cost (PVSC) ($M)	$	50,535	$	53,185	$	51,430	$	50,506	$	50,577
PVSC Delta vs. Preferred Plan ($M)	$	-	$	2,649	$	894	$	(29)	$	42
Other										
2023-2055 Natural Gas Burn (MMBtu)		726,374,585		726,374,585		601,108,746		636,812,607		616,901,277
2028 Renewable Energy MWh (%)		83.0%		83.4%		84.2%		83.3%		84.0%

Other Optimized or Sensitivity Portfolios

Lower Flexible and Fully Dispatchable Alternate Portfolio

This portfolio ("Lower Dispatchable Plan") was developed by limiting the nameplate capacity level of flexible and fully dispatchable generation to the level in the Preferred Plan less 20 percent. Because the Preferred Plan under SCC resulted in over 600 MW of gas-fired resources, this portfolio was limited to approximately 500 MW of gas-fired resources and reoptimized using the technology-specific minimum capacities from the Preferred Plan. As a result, an additional 400 MW of solar capacity was selected in the southeast region where no other solar bids had been selected previously, maximizing the accredited capacity to replace the approximately 100 MW decrease in gas-fired resources. Table 27 shows a comparison of the Preferred Plan (SCC) with the Lower Dispatchable Plan (SCC).

Table 27 - Preferred Plan (SCC) and Lower Dispatchable Plan Comparison

Portfolios' Comparison of Key Characteristics

Nameplate Capacity (MW)	1 - Preferred Plan (SCC)	6 - Lower Dispatchable Plan (SCC)
Biomass	19	19
Gas	628	504
Solar	1,969	2,369
Storage	1,170	1,170
Wind	3,406	3,406
TOTAL Nameplate Additions (MW)	7,192	7,467
Flexible Capacity (MW)	1,817	1,693
Colorado Power Pathway (CPP) Trx Utilization (MW)	4,411	4,811
CPP May Valley-Longhorn Extension Trx Utilization (MW)	1,206	1,206
Accredited Capacity (MW)	1,621	1,545
Section 123 Capacity (MW)	19	19
Owned Capacity (MW)	4,787	4,587
Owned Capacity (%)	66.6%	61.4%
Owned Energy (%)	69.7%	65.7%
Accredited Capacity Position		
2028 Capacity Position Long/(Short) (MW)	100	24
2028 Actual Reserve Margin (%)	19.7%	18.5%
Planning Period Present Value Revenue Requirement (PVRR) ($M)		
NPV Base Portfolio Costs ($M)	$ 41,708	$ 41,682
NPV Trx PO-PF Interconnection Costs ($M)	$ 130	$ 157
NPV Trx Network Upgrades for Delivery ($M)	$ 2,353	$ 2,353
TOTAL PVRR ($M)	$ 44,191	$ 44,192
PVRR Delta vs. Preferred Plan ($M)	$ -	$ 1
Emissions		
2023-2030 CO2 (M Tons)	69,322,272	68,775,275
2023-2055 CO2 (M Tons)	93,063,889	91,044,125
2023-2055 CO2 Delta vs. Preferred Plan (M Tons)	-	(2,019,764)
2030 CO2 Reduction from 2005 (%)	-87.4%	-87.8%
2023-2055 NPV CO2 at SCC ($M)	$ 6,288	$ 6,175
2023-2055 NPV Methane at SCM ($M)	$ 57	$ 54
TOTAL Present Value Societal Cost (PVSC) ($M)	$ 50,535	$ 50,421
PVSC Delta vs. Preferred Plan ($M)	$ -	$ (114)
Other		
2023-2055 Natural Gas Burn (MMBtu)	648,263,108	620,831,187
2028 Renewable Energy MWh (%)	83.0%	83.9%

High Project Labor Agreement ("PLA") Portfolio

This portfolio was designed maximize the number of bids that propose the use of a PLA. Therefore, this portfolio was developed by excluding bids with BVEM scores less than 50%. As a result, relative to the Preferred Plan, the minimum BVEM score of the projects in the portfolio increased from 1% to 61%, the portfolio average BVEM score increased from 57% to 79%, and the number of projects selected with 100% BVEM scores increased from five to seven.

Table 28 - Preferred Plan (SCC) and High Project Labor Agreement (PLA) (SCC) Comparison

Portfolios' Comparison of Key Characteristics

Nameplate Capacity (MW)	1 - Preferred Plan (SCC)	7 - High Project Labor Agreement (PLA) (SCC)
Biomass	19	19
Gas	628	647
Solar	1,969	2,119
Storage	1,170	1,187
Wind	3,406	3,608
TOTAL Nameplate Additions (MW)	7,192	7,580
Flexible Capacity (MW)	1,817	1,853
Colorado Power Pathway (CPP) Trx Utilization (MW)	4,411	5,418
CPP May Valley-Longhorn Extension Trx Utilization (MW)	1,206	1,862
Accredited Capacity (MW)	1,621	Not Modeled
Section 123 Capacity (MW)	19	19
Owned Capacity (MW)	4,787	5,339
Owned Capacity (%)	66.6%	70.4%
Owned Energy (%)	69.7%	79.3%
Accredited Capacity Position		
2028 Capacity Position Long/(Short) (MW)	100	n/a
2028 Actual Reserve Margin (%)	19.7%	n/a
Planning Period Present Value Revenue Requirement (PVRR) ($M)		
NPV Base Portfolio Costs ($M)	$ 41,708	$ 42,159
NPV Trx PO-PF Interconnection Costs ($M)	$ 130	$ 109
NPV Trx Network Upgrades for Delivery ($M)	$ 2,353	$ 2,353
TOTAL PVRR ($M)	$ 44,191	$ 44,620
PVRR Delta vs. Preferred Plan ($M)	$ -	$ 429
Emissions		
2023-2030 CO2 (M Tons)	69,322,272	69,892,489
2023-2055 CO2 (M Tons)	93,063,889	92,647,344
2023-2055 CO2 Delta vs. Preferred Plan (M Tons)	-	(416,545)
2030 CO2 Reduction from 2005 (%)	-87.4%	-87.8%
2023-2055 NPV CO2 at SCC ($M)	$ 6,288	$ 6,278
2023-2055 NPV Methane at SCM ($M)	$ 57	$ 56
TOTAL Present Value Societal Cost (PVSC) ($M)	$ 50,535	$ 50,954
PVSC Delta vs. Preferred Plan ($M)	$ -	$ 419
Other		
2023-2055 Natural Gas Burn (MMBtu)	648,263,108	640,480,632
2028 Renewable Energy MWh (%)	83.0%	83.6%

Annuity Method Sensitivity Portfolios

The terms “annuity method” and “replacement chain method” represent different approaches for backfilling bids with lives that expire within the 2021-2054 Planning Period. In Paragraph 4 of the Updated Settlement Agreement, the Company agreed that for the selected portfolios in Attachment 1, the Company will create sensitivities that optimize the EnCompass model runs in Phase II using the annuity method in addition to the replacement chain method to bookend the measurement of the modeled effects of generation with different lives during the Planning Period (i.e., through 2055). These portfolios are portfolios 1, 2, 4, 5 and 9 (i.e., Preferred Portfolio, Preferred Portfolio with House Bill 21-1234 Resources, 40 Percent Ownership Test Portfolio with No Upper Constraint, Midpoint Ownership Portfolio, and Accelerated CO2 Reduction Portfolio).

As discussed in Section 3.6, the Accelerated CO2 Reduction Portfolio was not modeled as the original portfolio already exceeded the early carbon reduction target, so only four portfolios remained to model using the annuity method. These four portfolios were developed under the two carbon pricing assumptions ($0CO2 and SCC).

When developed, the 40 Percent Ownership Test Portfolios with the annuity method sensitivity exceeded 40% ownership, as similarly observed in the replacement chain scenarios. Thus, the Midpoint Ownership Portfolio using the annuity method was no longer applicable and not modeled.

In general, the annuity method sensitivity resulted in portfolios with more shorter-term PPA investments, especially gas-fired resources, and a reduction in the ownership percentage due to more PPA capacity. This is as expected, as the construct of the annuity method sets the replacement cost of the expiring bids equal to the initial costs (on an annuitized basis). As an example, a ten-year PPA with a levelized cost of $25/MWh is assumed to have a replacement for the next ten years also at $25/MWh; accordingly, it has no inflation or escalation throughout the modeling period. This makes shorter term contracts look more attractive on a NPV basis over the modeling period, all else being equal.

It is not appropriate to compare the costs of an annuity method sensitivity portfolio with a base assumptions portfolio and make a conclusion that one portfolio has higher/lower costs to customers. The annuity method sensitivity is a fundamentally different view of the future where resources can be replaced at a later time at lower cost than today, and any cost differences are related to this different viewpoint, not an inherent cost difference in the portfolios themselves. The annuity method sensitivity is most useful for seeing what bids would be selected given this different view of future costs, and not for comparing the costs directly.

The results of the annuity portfolios are shown below in Table 29 for the SCC view and Table 30 for the $0CO2 view.

Table 29 - Preferred Plan (SCC) Annuity and Annuity Plans (SCC) Comparison

Portfolios' Comparison of Key Characteristics

Nameplate Capacity (MW)	1 - Preferred Plan (SCC), Annuity Tail	2 - Inverse 1324 Plan (SCC), Annuity Tail	4 - 40% Ownership Test Plan (SCC), Annuity Tail	1 - Preferred Plan (SCC) - with Prospective New Load, Annuity Tail
Biomass	19	-	-	19
Gas	605	605	619	900
Solar	2,619	2,319	2,369	2,369
Storage	1,220	1,220	1,420	1,798
Wind	3,406	3,406	3,406	3,406
TOTAL Nameplate Additions (MW)	7,869	7,550	7,814	8,491
Flexible Capacity (MW)	1,844	1,825	2,039	2,717
Colorado Power Pathway (CPP) Trx Utilization (MW)	5,111	4,611	4,861	5,039
CPP May Valley-Longhorn Extension Trx Utilization (MW)	1,206	1,206	1,206	1,206
Accredited Capacity (MW)	Not Modeled	Not Modeled	Not Modeled	Not Modeled
Section 123 Capacity (MW)	19	-	-	19
Owned Capacity (MW)	4,137	4,118	4,540	4,787
Owned Capacity (%)	52.6%	54.5%	58.1%	56.4%
Owned Energy (%)	60.4%	62.8%	65.7%	65.6%
Accredited Capacity Position				
2028 Capacity Position Long/(Short) (MW)	Not Modeled	Not Modeled	Not Modeled	Not Modeled
2028 Actual Reserve Margin (%)	Not Modeled	Not Modeled	Not Modeled	Not Modeled
Planning Period Present Value Revenue Requirement (PVRR) ($M)				
NPV Base Portfolio Costs ($M)	$ 41,665	$ 41,327	$ 41,348	$ 42,776
NPV Trx PO-PF Interconnection Costs ($M)	$ 152	$ 152	$ 135	$ 142
NPV Trx Network Upgrades for Delivery ($M)	$ 2,353	$ 2,353	$ 2,353	$ 2,353
TOTAL PVRR ($M)	$ 44,170	$ 43,831	$ 43,835	$ 45,270
PVRR Delta vs. Preferred Plan ($M)	$ -	$ (338)	$ (334)	$ 1,101
Emissions				
2023-2030 CO2 (M Tons)	68,851,013	69,299,858	68,822,125	70,070,363
2023-2055 CO2 (M Tons)	89,955,069	91,936,124	90,731,793	93,671,660
2023-2055 CO2 Delta vs. Preferred Plan (M Tons)	-	1,981,055	776,724	3,716,591
2030 CO2 Reduction from 2005 (%)	-88.2%	-87.7%	-88.1%	-87.5%
2023-2055 NPV CO2 at SCC ($M)	$ 6,121	$ 6,230	$ 6,160	$ 6,337
2023-2055 NPV Methane at SCM ($M)	$ 53	$ 55	$ 54	$ 57
TOTAL Present Value Societal Cost (PVSC) ($M)	$ 50,345	$ 50,117	$ 50,049	$ 51,664
PVSC Delta vs. Preferred Plan ($M)	$ -	$ (227)	$ (296)	$ 1,320
Other				
2023-2055 Natural Gas Burn (MMBtu)	605,544,521	632,663,679	611,325,742	650,741,860
2028 Renewable Energy MWh (%)	84.2%	83.4%	83.7%	83.4%

Table 30 - Preferred Plan ($0CO2) Annuity and Annuity Plans ($0CO2) Comparison

Portfolios' Comparison of Key Characteristics

Nameplate Capacity (MW)	1 - Preferred Plan ($0CO2), Annuity Tail	2 - Inverse 1324 Plan ($0CO2), Annuity Tail	4 - 40% Ownership Test Plan ($0CO2), Annuity Tail	1 - Preferred Plan ($0CO2) - with Prospective New Load, Annuity Tail
Biomass	19	-	-	19
Gas	681	681	800	824
Solar	1,619	1,619	1,419	2,069
Storage	1,848	1,848	1,420	2,248
Wind	1,700	1,700	2,001	2,906
TOTAL Nameplate Additions (MW)	5,866	5,847	5,640	8,066
Flexible Capacity (MW)	2,548	2,529	2,220	3,091
Colorado Power Pathway (CPP) Trx Utilization (MW)	2,933	2,933	3,206	4,789
CPP May Valley-Longhorn Extension Trx Utilization (MW)	-	-	-	1,206
Accredited Capacity (MW)	Not Modeled	Not Modeled	Not Modeled	Not Modeled
Section 123 Capacity (MW)	19	-	-	19
Owned Capacity (MW)	3,131	3,112	3,785	4,787
Owned Capacity (%)	53.4%	53.2%	67.1%	59.3%
Owned Energy (%)	67.6%	67.2%	74.1%	75.8%
Accredited Capacity Position				
2028 Capacity Position Long/(Short) (MW)	Not Modeled	Not Modeled	Not Modeled	Not Modeled
2028 Actual Reserve Margin (%)	Not Modeled	Not Modeled	Not Modeled	Not Modeled
Planning Period Present Value Revenue Requirement (PVRR) ($M)				
NPV Base Portfolio Costs ($M)	$ 42,047	$ 41,765	$ 41,453	$ 42,820
NPV Trx PO-PF Interconnection Costs ($M)	$ 95	$ 93	$ 93	$ 114
NPV Trx Network Upgrades for Delivery ($M)	$ 1,972	$ 1,972	$ 1,972	$ 2,353
TOTAL PVRR ($M)	$ 44,114	$ 43,830	$ 43,518	$ 45,287
PVRR Delta vs. Preferred Plan ($M)	$ -	$ (284)	$ (597)	$ 1,173
Emissions				
2023-2030 CO2 (M Tons)	73,383,754	73,396,269	73,015,545	72,246,441
2023-2055 CO2 (M Tons)	102,381,931	102,392,278	103,013,414	99,162,215
2023-2055 CO2 Delta vs. Preferred Plan (M Tons)	-	10,346	631,483	(3,219,716)
2030 CO2 Reduction from 2005 (%)	-85.4%	-85.4%	-85.1%	-86.3%
2023-2055 NPV CO2 at SCC ($M)	$ 6,851	$ 6,852	$ 6,876	$ 6,670
2023-2055 NPV Methane at SCM ($M)	$ 68	$ 68	$ 69	$ 64
TOTAL Present Value Societal Cost (PVSC) ($M)	$ 51,033	$ 50,750	$ 50,463	$ 52,021
PVSC Delta vs. Preferred Plan ($M)	$ -	$ (283)	$ (571)	$ 988
Other				
2023-2055 Natural Gas Burn (MMBtu)	775,598,987	775,949,453	790,851,382	726,384,453
2028 Renewable Energy MWh (%)	77.6%	77.4%	78.0%	81.5%

5.0 Natural Gas Considerations

This Section 5.0 provides an overview and discussion of natural gas considerations and related issues that resulted from the Phase I process. First, the Company provides a discussion as to why existing gas units were not re-bid for longer life extensions based on its evaluation of Company-owned gas generation units with retirement dates within the RAP, followed by a brief discussion of potential short-term life extensions due to transmission considerations in the Denver metro constraint. Next, this Section provides a discussion of requirements established in Phase I for natural gas resources, including depreciation lives, clean fuels capability, and fuel requirements. Finally, this Section discusses how the gas resources included in the Preferred Plan meet each of the Phase I requirements.

5.1 Rebidding of Existing Company-Owned Gas Units in the RFP

Background

In Paragraph 23 of the Updated Settlement Agreement (approved by Paragraph 282 of the Phase I Decision), the Company agreed it would re-bid any existing gas units that are scheduled for retirement in the RAP (i.e., 2021-2030) so long as the unit does not have to be retired pursuant to the Colorado State Implementation Plan under the Clean Air Act ("SIP") and is reasonably expected to perform in a manner that can balance the Company's system.

The Company-owned gas units that are scheduled for retirement prior to 2030 (and are not otherwise scheduled for retirement pursuant to the SIP) include Alamosa, Fruita, Fort Lupton, and Valmont 6—all of which are scheduled to retire in 2026.[68] Pursuant to the terms of Paragraph 23 of the Updated Settlement Agreement, the Company evaluated whether to re-bid any particular gas unit, with additional capital investment and O&M necessary to life extend the unit for at least several years, based on whether the unit: (1) has the flexibility necessary to assist in the integration of the increasing levels of variable generation that the Company expects as part of this 2021 ERP & CEP; and (2) assists in maintaining a reliable system. Based on this evaluation, and as discussed in further detail below, the Company chose not to re-bid these gas units.

Summary of Company Findings

The Company's detailed evaluation of rebidding opportunities determined that re-bidding the existing units at Alamosa, Ft. Lupton, Fruita, and Valmont 6 would create undue future reliability risks and come at high cost. This determination was principally due to the age and condition of the units and the lack of replacement parts.

[68] See Table 2.4-2 of Volume 2, Technical Appendix, Rev. 2 filed on December 6, 2021.

As part of its evaluation, the Company engaged in discussions with General Electric ("GE"), the original manufacturer of all of the existing CT units at issue, to determine what equipment could be restored to conditions allowing for re-bidding and a sustained life extension. This included discussion as to what components of the units would need to be replaced in order to facilitate a re-bid and corresponding life extension for each unit. These discussions led the Company to the conclusion that rebuilding the units to a reliable condition would be a long, complex, and costly task; moreover, it was likely that the Company would find an extensive number of obsolete elements in the restoration process, leading to uncertainty about the total amount of costs in the process. More specifically, many of the parts for the units would need to be made to order and future replacements would have a long lead time (while GE was unable to provide an estimated lead time, the Company expects an approximately six months to one year lead time). As summarized in Table 31 below, the units have been in-service for approximately 50 years and are at or near the end of life. At a minimum, the generator, generator step up ("GSU") transformer, electrical gear, combustion turbine auxiliaries, and wiring would need to be replaced due to the age of the materials and equipment to ensure the reliability and unit operating flexibility needed to support the system needs. Additionally, the foundations and associated structures would need to have a detailed evaluation to determine if they are in good condition and whether they could support the extended life of the units. If not, foundations and associated structures would need to be repaired or replaced, with corresponding cost and timing impacts for restoration.

Table 31 - Summary of Existing Company-owned Gas Units

Unit	Size (MW)*	Fuel	Original Year of Operation	Plant Age	End of Operation Year	Book Life Retirement Year
Alamosa 1	13	Natural Gas/Oil	1973	50	2026	2026
Alamosa 2	14	Natural Gas/Oil	1977	46	2026	2026
Ft. Lupton 1	44	Natural Gas	1972	51	2026	2026
Ft. Lupton 2	44	Natural Gas	1972	51	2026	2026
Fruita	14	Natural Gas/Oil	1973	50	2026	2026
Valmont 6	43	Natural Gas	1973	50	2026	2026

The process, estimated timeframe, equipment inspection requirements, and the steps required to restore the units to a reliable condition to support the system in the future are discussed below.

The unit restoration process would involve the following steps:

- Plan extended outage (i.e., approximately 18 months) so unit can be disassembled, inspected, and restored.
- Develop equipment list and material list of all items that may need to be replaced.
- Obtain Company and contract resources to disassemble unit so it can be inspected.

- Mobilize resources and equipment needed for inspection.
- Perform inspection, record condition and findings of equipment, including cables, wiring, piping, instrumentation, and enclosures.
- Review findings and develop list of items that need to be replaced, rebuilt, or repaired, with a plan to replace or rebuild with new materials all items that have extensive wear, material degradation, cracks, loss of performance/reliability, or other issues.
- Determine source of supply for equipment needed; based on this sourcing determination develop specification and issue request for proposal to obtain pricing and lead time.
- For items that need to be rebuilt or repaired, first develop process and procedures to restore the equipment. Second, develop a list of the resources and material needed for the restoration and a cost and schedule for each of the restoral items.
- Develop cost estimate and schedule for all work that would need to be performed to restore the unit to the condition needed to allow for reliable continued service.
- Manage the process of developing the contracts and specifications to obtain the resources and materials to complete the restoration.
- Develop testing and inspection plans for each of the items both for manufacturing and field restoral activities.
- Monitor and track all work to ensure quality, safety requirements, and compliance with design specifications.
- Once all materials have been obtained and resources are available, then rebuild unit.
- Develop commissioning plan for the unit.
- Commission the unit.

Table 32 - Equipment Inspection Requirements

Instrumentation Components	Gas Turbine Ventilation
Instrument Cabling	Water Wash System
Motor Control Centers	Filter Houses
Natural Gas System	Pulse Jet Systems
Control Valves	Atomizing Air
Generator Protection System	Liquid Fuel Systems
Turbines (overall condition)	Liquid Fuel Storage Tanks
Gas Turbine Enclosure	Turbine Instruments
Starting Systems	Generators Excitatory Power Mgt System
Accessory Gearboxes	Generator Cooling System
Auxiliary Cooling System	Generator Stator Core and Field
Lube Oil System	Demineralized Water System
Load Gearboxes	Demineralized Water Storage Tanks
Accessory Gearboxes	Instrument Air Compressors
Auxiliary Cooling System	Fire Water Pumps and Distribution System
Exhaust Stack and Silencers	Fire Water / Raw Water Storage Tank

<u>Schedule of Rebuild</u>

As shown in Table 32 above, the units are scheduled be retired at the end of 2026. To rebuild the units, starting at the end of 2026, the Company would begin the effort by putting contracts in place for disassembly and inspection of the units. The disassembly and inspection process is estimated to take approximately three to four months. The lead time required for equipment replacement is not known at this time, but GSU lead times are running approximately 18 months. Equipment known to need replacement would be ordered ahead of the outage to minimize the outage time. Further, and most important from a resource adequacy perspective, the Company estimates it would require a planned outage of approximately 18 months to ensure all work that needs to be performed could be completed. The Company notes that this planned outage down time may not be acceptable from a reliability standpoint, so it would require the purchase of replacement power while the unit is down, the cost of which will depend entirely upon market conditions and availability of such power, with an unknown emissions impact as sources cannot be identified this far in advance.

In summary, the Company determined that the age of the equipment, over 50 years in most cases, made it unacceptable to expect reliable operation of these existing units for an extended period in the future beyond their current 2026 end of life. Much of the equipment would need to be replaced or completely rebuilt. Since the equipment is not currently supported by the original manufacturer, replacement parts would need to be built to order, resulting in long lead times and high cost. For these reasons, the Company decided not to re-bid these existing gas units, as they would not reasonably assist in maintaining a reliable system without significant capital investment and O&M to extend the life of the units.

5.2 Potential Short-term Extension of Select Existing Company-Owned Gas Units

Due to the transmission considerations discussed in Section 3.8, primarily the challenges and solutions regarding the Denver metro constraint, the Company is currently analyzing the potential for a very short-term life extension (e.g., 12 to 36 months) of the Valmont 6 and Fort Lupton 1&2 CTs, subject to any required Commission approvals. As discussed in the prior section, the units are not candidates for full life extension because the Company does not believe they can contribute to the long-term reliability of the system or integrate the Company's large renewable portfolio. However, while these units may not be suitable for long-term extensions, very short-term extensions may be technically feasible. The Company will continue to investigate this option and come back to the Commission in a future filing if this option proves beneficial.

5.3 Phase I Requirements for New Natural Gas Resources

Depreciation Lives of New Gas Assets

Consistent with Paragraph 24 of the Settlement Agreement, for Phase II modeling purposes, the Company limited the depreciation lives for new natural gas assets to 25 years. In its Phase I Decision, the Commission found that limiting the depreciation lives of new natural gas assets to 25 years for purposes of Phase II modeling better aligns with state policy and the 100 percent clean energy goal by 2050, better aligns with the Company's own public commitment regarding clean energy by 2050, and better aligns with the term for third party-owned gas units as set forth in the PPAs.[69] For any new natural gas assets included in a final approved resource plan, the Company will address the depreciable life for such assets for ratemaking purposes through an appropriate future depreciation study.

Clean Fuel Capability

Paragraph 23 of the Settlement Agreement affirmed that the Company would retain requirements regarding clean fuel capability for new natural gas generation bids as proposed in its Phase I Direct Case.[70] Specifically, the Company included language in the RFP document that encouraged bids proposing a new CT facility or new reciprocating engine facility to provide an option for the facility to be capable of burning, at a minimum, 30 percent clean fuel (by volume), over the entire operating range of the

[69] Decision No. C22-0459, at ¶278.
[70] Hrg. Ex. 104, (Hill Direct Testimony), at pgs. 74-75.

unit (i.e., from minimum MW loading to maximum MW loading) while meeting emission permit requirements. This alternative fuel capability will allow the Company to transition toward our goal of a carbon-free future by 2050. Additionally, as provided in Paragraph 23 of the Settlement Agreement, the Company will ensure the final contract terms for any clean fuel-capable resource includes the option for clean fuel, as bid, including the unique bidder proposed model PPA terms and conditions associated with the clean fuel option.

In Paragraph 279 of its Phase I Decision, the Commission approved the provisions of Paragraph 23 of the Settlement Agreement but made further modifications to encourage bidders to voluntarily report the *maximum* hydrogen mixing capability. The Commission found that doing so could provide valuable information regarding where the market is at and whether it provides a pathway to achieve the State's 100 percent clean energy target by 2050.

<u>Backup Fuel and Other Dispatchable Resource Capabilities</u>

In its Phase I Direct Case, the Company also proposed amending the model PPA for dispatchable resources to have the following capabilities:[71]

- the Company is able to remotely start simple cycle facilities at all hours;
- any new, repowered, or rebid generating units within a plant is able to start simultaneously;
- a unit can start on either natural gas or fuel oil at the Company's election and can switch between fuel oil and gas without interruption;
- simple-cycle generators are capable of starting within ten minutes (fast start capability);
- sellers must provide a bid that includes a plan to have fuel and any ancillary product on site necessary to permit the facility to run continuously for a minimum of 72 hours at maximum load on alternative fuel; and
- firm gas transportation contracts could serve as a substitute for the requirement to have an alternative such as fuel oil on site.

Regarding the capability to run continuously for 72 hours, during the evidentiary hearing in December 2021, Company witness Mr. John Welch testified that this 72-hour period could reasonably be extended to four or five days based on conditions experienced

[71] Hrg. Ex., 117 (Fowler Direct Testimony), at pgs. 7-8; Hrg. Ex. 106 (Welch Direct Testimony), at pgs. 18-21.

during Winter Storm Uri.[72] In Paragraph 280 of its Phase I Decision, the Commission found it reasonable to extend the 72-hour onsite fuel requirement to at least five days given the uncertainty regarding the length of cold weather events like Storm Uri and Mr. Welch's testimony at the evidentiary hearing.

The Commission approved both the alternative fuel requirement and the other dispatchable resource capabilities listed above for new gas resources in Paragraph 281 of its Phase I Decision. However, the Commission urged the Company to be flexible in applying these requirements to existing gas units such that an existing gas unit's rebid shall not be discarded automatically if the unit is unable to meet one of the requirements and directed the Company to use good judgment when evaluating the rebid of existing gas units to enable the continued use of these units over the construction of new units wherever possible.

5.4 Consistency of New Gas Resources with Phase I Requirements

Description of New Gas Resources Advanced to Computer-Based Modeling

Of the 44 individual gas generation bids that were received in the RFP, 33 bids were advanced to computer-based modeling, with 28 of those bids being new gas builds. The following discussion addresses each of the Phase I requirements listed above as it pertains to the 12 bids that were included in the various portfolios discussed in this Report. Five of the 12 bids are extensions of existing PPAs, and as discussed in Section 5.3, were not automatically disqualified even though they are unable to meet all of the Phase I requirements. Table 33 provides a summary of gas bids that were included in the various portfolios presented in this Report.

[72] Hearing Transcript, December 13, 2021, at pgs. 239-241.

Table 33 -Summary of Gas Bids Included in Portfolios[73]

Bid ID	Preferred Plan/Backup Bid	Commercial Structure	Nameplate (MW)	Summer NDC (MW)	Configuration	New Gas Resource	Fuel Flexible	Firm gas	Fuel Storage/Alternate Available
0011		Own	49.5	27.5	[redacted]	Yes	Yes	No	Company to Develop
0235	Backup Bid	PPA	219	209	Simple Cycle Combustion Turbine	Yes	Yes	Yes	No
0510	Backup Bid	PPA	147	127	Combined Cycle - 2 x 1	No	No	Yes	No
0514	Backup Bid	PPA	30	25	Simple Cycle Combustion Turbine	No	No	Yes	No
0517		PPA	147	147	Combined Cycle - 2 x 1	No	No	Yes	No
0538		PPA	30	25	Simple Cycle Combustion Turbine	No	No	Yes	No
0986	Preferred Plan	Own	28.4	22.9	Dual Fuel Aeroderivative Combustion Turbine	Yes	Yes	No	Fuel Oil Storage
0989	Preferred Plan	Own	200	189.7	Dual Fuel Simple Cycle Combustion Turbine	Yes	Yes	No	Fuel Oil Storage
0991		Own	400	379.4	2 - Simple Cycle Combustion Turbines	Yes	Yes	Yes	Alternate Fuel Oil Storage Bid Available
0997		Own	200	189.7	Simple Cycle Combustion Turbine	Yes	Yes	Yes	Alternate Fuel Oil Storage Bid Available
1000	Preferred Plan	Own	400	379.4	2 - Simple Cycle Combustion Turbines	Yes	Yes	Yes	Alternate Fuel Oil Storage Bid Available
1061		PPA	75.5	68	Combined Cycle - 1 x 1	No	No	Yes	No

<u>Depreciation Lives of New Gas Assets</u>

In the development of revenue requirements used in bid evaluation, the Company confirms that the depreciation lives of new natural gas assets were limited to 25 years.

<u>Clean Fuel Capability</u>

When considering the modeling discussion presented in Section 3, and the need for firm dispatchable resources to meet the reliability constraints in each of the portfolios except for the No Gas Plan, the clean fuel capability of natural gas bids is of critical importance. We believe that the capabilities present in the bids received will allow new firm dispatchable resources to be a viable capacity backstop for our increasing portfolio of renewable and energy limited resources without compromising progress toward emissions reduction objectives. In fact, all the new gas generation bids advanced to modeling will be able to burn 30% clean fuels beginning on the COD, which was the minimum amount of clean fuel combustion desired by the Company and affirmed by the Commission in this RFP. The two major combustion turbine manufacturers represented in the bids are GE and Siemens, both of which are developing clean fuel combustion systems for their turbine platforms.

For example, in the case of Bid 0235, the Siemens SGT6-5000F is described as being able to currently burn up to 30% hydrogen by volume, with plans to reach 100% hydrogen blending in the future. Bid 0011 is a [redacted] that is already capable of 100% clean fuel combustion due to its unique design. The bid explicitly provides hydrogen, ammonia, and biogas as fuel source options, and states that the units can switch fuels "on the fly" to meet changing dispatch needs. Finally, the other new gas

[73] "Fuel Flexible" refers to a unit's ability to burn fuel blends that contain a percentage of clean fuels by volume.

bids propose different GE combustion turbine options, with one being the LM2500Xpress aeroderivative turbine and the others being one or two 7F.05 simple cycle turbines. The LM2500 is currently capable of burning up to 30% hydrogen by volume, with a modification package in development that would allow the unit to be converted to 100% hydrogen by 2030. The 7F.05 is currently capable of 5% combustion of hydrogen by volume, with plans to achieve 30% by 2026 (and ready for project COD) and the ability to install combustion upgrades that would allow 100% hydrogen fuel by 2035. In summary, the new gas bids received in this ERP satisfy the clean fuel requirements laid out in Phase I and would provide the opportunity to maintain a diverse portfolio of resources and firm dispatchable generation that is critical to reliability as the availability and cost effectiveness of clean fuels progress.

<u>Backup Fuel and Other Dispatchable Resource Capabilities</u>

All bids that were advanced to EnCompass modeling are compliant with the requirement for either onsite backup fuel storage or firm gas transportation contracts. In some cases, a project was bid into the RFP with both a gas option and an alternate option for backup fuel oil and storage. As there were no limitations on the natural gas supply in the model, the EnCompass model did not select the fuel oil storage bids due to economics. The backup fuel is never utilized; therefore, the model would see any extra cost as providing no benefit and would not select the backup fuel bid if the gas option was less expensive and available. Thus, the bids that included both the option for firm gas and backup fuel were included in the model with the least cost option, generally firm gas, and the decision to select the backup fuel option instead is a risk assessment of the incremental costs versus potential utilization of the backup fuel and associated benefit. For any bid that did not have fuel oil storage backup, the Company included estimates for firm gas transportation contracts in the fuel costs added to the bid.

Of the twelve bids included in portfolios, two are dual fuel units that will have onsite fuel oil storage that would allow five days of operation on fuel oil at full load. Both of these units are included in the Preferred Plan. A third, Bid 0011, is the [redacted] that is designed to provide fuel flexibility for future operations, but only operates on gaseous fuels. Therefore, it would not be eligible for traditional fuel oil backup storage that is common to dual fuel gas turbines and cannot take advantage of fuel oil on the Alamosa site. The bidder did not include secondary fuel storage in their pricing but discussed the potential to develop onsite storage of either hydrogen or propane for 72-hour operations should the Company want to explore that option. As this bid is a Company ownership proposal, the Company included an estimate for developing a 5-day LNG storage solution in the fixed fuel costs assigned to the bid in modeling.

While this means that nine of the twelve bids would rely on firm gas contracts in lieu of onsite fuel oil storage to meet the Commission requirements, three of the bids were submitted with alternate bids that provided an option for dual fuel with fuel oil storage. Two of those three also included another option for both fuel oil storage and black start capability. Table 34 below shows a cost comparison for these alternate bids. Should the Commission decide it would prefer a specific project be included in the final plan with fuel oil storage or with fuel oil storage and black start capability, the Table below shows the estimated incremental cost for the additional options.

Table 34 - Cost Comparison Between Gas Only Bids and Alternate Options

Bid ID	Preferred Plan or Backup Bid	Natural Gas Only	Dual Fuel, Fuel Oil Storage	Dual Fuel, Fuel Oil, Black Start	PVRR ($M)	Delta ($M)
0991	-	x			$709	$ -
1119	-		x		$769	$60
1120	-			x	$851	$142
0997	-	x			$293	$ -
1005	-		x		$326	33
1000	Preferred	x			$607	$ -
1115	-		x		$662	$55
1118	-			x	$752	$145

The other capabilities discussed in Phase I address the ability of the Company to dispatch units quickly to respond to an increasingly dynamic system and to trust that a unit will operate when its capacity is needed.

Each of the new gas bids that are included in portfolios are simple cycle configuration and equipped with fast start and shutdown capability, allowing for fast response to system demands. Due to the compact, modular nature of the [redacted] Bid 0011 claims to be able to reach minimum load in two minutes, with 100% load reached within 10 minutes. The Siemens SGT6-5000F in Bid 0235 is being described as able to reach minimum load in five minutes, while reaching 70% load in 10 minutes and full load in 15 minutes. The GE LM2500Xpress in Bid 0986 comes with varying quick start packages, with this specific bid reaching minimum load in five minutes and full load in 10 minutes. The larger GE 7F.05 presented in the rest of the new gas bids is understandably slower to ramp up to full load than its smaller counterparts but is still able to reach minimum load in 10 minutes with full load achievable within 30 minutes. Regarding the other dispatchable resource capabilities, the Company confirms that it did include the requirement for remote and simultaneous start on natural gas (or fuel oil if applicable) at all hours in Article 10 – Operations and Maintenance of the PSCo Model Dispatchable PPA. This requirement was not disputed in Model PPA redlines.

<u>New Gas Resources in the Preferred Plan</u>

In summary, the Preferred Plan includes three new gas resource bids that have fully met the requirements laid out in Phase I and provide reliability in multiple ways. First, two of the three bids include dual fuel capability with five days of fuel oil storage backup which will allow the units to maintain reliability in extreme weather conditions and through disturbances in natural gas supply. These two units are also strategically located to provide necessary firm dispatchable generation in the San Luis Valley or within the Denver metro area. All three bids include gas turbines that have a proven track record of durability and reliability and will incorporate clean fuel capable combustion systems from day one with a path towards 100% clean fuel combustion in the near future. We believe that the units presented in the Preferred Plan are the optimal solution for providing the reliability and capacity that is needed as we continue to move towards a zero-carbon future.

6.0 Transmission

This Section describes the transmission investments necessary to support this resource acquisition, as well as the drivers of those investments, with a focus on the Preferred Plan.

6.1 Introduction

For purposes of this Phase II process, the Company's Transmission team embarked on Public Service's most thorough transmission analysis to accompany an ERP to date. The challenge to the Company in interconnecting a portfolio of this size and accommodating generation retirements is a substantial one. The Company is a first mover in addressing this issue and is building infrastructure to accommodate thousands of MWs of inverter-based variable energy resources for a large and growing load base that is geographically isolated. Leveraging the Company's experience developing transmission projects to support large-scale resource acquisitions, our team started from the ground up: our first step was to re-analyze the transmission system as it exists today. We then spent numerous hours running power flow studies, scenario modeling, and running tabletop exercises to develop project scoping and cost estimates leading to a comprehensive, albeit preliminary, package of transmission investments identified in this Report. Recognizing that the processes and technologies involved in making this a reality while maintaining reliability and affordability will continue to be tested and to evolve, the results of this effort are discussed in detail in the 2021 ERP & CEP Phase II Transmission Report, included in Appendix Q.

While earlier stages of clean energy-driven transmission planning were primarily focused on connecting remotely located wind and solar generation to load centers, the Company's analysis of the clean energy resource acquisitions proposed in this Phase II process clearly demonstrated that it is not only the generation mix that must change to enable the clean energy transition: the transmission system must evolve as well. The Company's transmission portfolio is tailored to its Preferred Plan; however, it is critical to understand that similar investment would be needed to support *any* of the Clean Energy Plan portfolios identified in this Report due to the magnitude of clean energy being acquired. Given the width and breath of this historic task, the investment is significant. The Company's current estimate for these investments is $2.82 billion.[74]

Our studies identified a significant need to develop transmission projects that allow for the Company to deliver electricity within and around our largest (and still growing) load center, the Denver metro area. Delivery of remote resources is, and will remain, an important consideration in transmission planning, as evidenced by the foundational role

[74] As discussed in Section 6.2, this estimate does not account for generator interconnection costs.

that the CPP plays and the cost-effectiveness of the MVLE in the Preferred Plan. In addition to this consideration, though, as the Company moves toward a grid powered primarily by renewable resources, transmission investments are increasingly focused on enhancing the capacity and resilience of the entire transmission grid—especially those parts of the grid located closest to our customers' homes and businesses. System operations will be hamstrung without these investments, and we would expect to see increased curtailments as well as an increase in the dispatch and operation of carbon-based resources.

Furthermore, the identified transmission investments are not limited to infrastructure that delivers renewable electricity to our customers. The transition away from grid-synchronized generators to a system powered primarily by inverter-based renewable resources requires additional projects to maintain the voltage and strength of the transmission system. The Company expects the need for devices such as Static Synchronous Compensators ("StatComs") and synchronous condensers and continues to evaluate the scope of this work.

We all must recognize that with the historic achievements the Preferred Plan seeks to deliver, transmission projects cannot and should not be developed to fit a specific set of inputs directly before us. The transmission projects identified here are being planned with an eye towards the future as well. The transmission portfolio presented here will create substantial value for customers by helping to facilitate, in part, future system growth and electric resource planning processes that will continue to increase the deployment of clean energy resources in Colorado.

6.2 Transmission Cost Estimate by Category

In conducting our analysis of the Preferred Plan, we developed project cost estimates based on preliminary project scopes using the Company's cost estimation process, experience from recent projects, and indicative cost estimate guides to inform our analysis while making adjustments to account for inflation and project risks. The Phase II Transmission Report, provided as Appendix Q, describes in detail the practices that the Company implemented in support of developing the portfolio of transmission projects and associated cost estimates, while also providing insights into how key assumptions and variables could affect the final cost of transmission projects. The Company will keep stakeholders and the Commission apprised of updated project scopes and refined cost estimates through the appropriate forums, such as annual Rule 3206 Reports or applications for CPCNs filed pursuant to Commission Rules 3102 and 3206.

As the Company discussed in Phase I of this proceeding, transmission projects are broken-down into the following categories: (1) Denver metro area upgrades, (2) grid (strength) reinforcement, (3) reactive/voltage support, and (4) generation interconnection facilities. While these classifications still broadly represent the transmission facilities that the Company has identified in support of the Preferred Plan,

Table 35 below provides the Company's transmission cost estimates for three categories of investment needed to support the Preferred Plan. Table 35 identifies the Company's cost estimates for: (1) the MVLE, consistent with the Commission's directive in Proceeding No. 21A-0096E, (2) network upgrades for the Denver metro and San Luis Valley areas, and (3) the combined scope of both grid strength reinforcements and reactive/voltage support projects. The specific transmission projects that fall within these categories are all identified and discussed in detail in the Phase II Transmission Report. The Company discusses interconnection cost estimates separately below as the cost estimates developed for the purposes of this 120-Day Report do not provide a comparable estimate to those developed for other categories of transmission projects.

Table 35 - Transmission Portfolio Cost Estimate by Category

Transmission Cost Category	Estimated Cost ($M)
Denver Metro Transmission Network Upgrades	$2,146
San Luis Valley Transmission Network Upgrades	$176
May Valley – Longhorn Extension (MVLE)	$252
Grid Strength Reinforcement and Reactive/Voltage Support	$250
Total	$2,820

As described in the Phase II Transmission Report, the generation interconnection costs developed for this Report—approximately $123 million in capital costs—were developed in accordance with the bid evaluation procedures outlined in Phase I and were appropriate for purposes of selecting bids and creating portfolios. However, given their upfront use in the bid evaluation process, the Company's interconnection cost estimate was developed in a different manner than other transmission costs included in this Report, relying on publicly available historic interconnection studies and their associated cost estimates instead of project scope developments. As such, the Company anticipates that the actual costs that will be incurred in constructing these facilities will vary from this estimate. The Company will develop refined interconnection cost estimates for resources selected in this Phase II process as part of its FERC-governed interconnection process set forth in the Large Generator Interconnection Process ("LGIP") contained in Xcel Energy's Open Access Transmission Tariff ("OATT") and will present this information to the Commission in necessary future filings.

6.3 The Need for Transmission System Investments

Growth, portfolio size, and the nature of the bid pool are key drivers of the transmission investment need identified above and explained in more detail in the 2021 ERP & CEP Phase II Transmission Report.

Public Service acknowledges the transmission cost estimate discussed here and in the Phase II Transmission Report is higher than initially estimated in prior proceedings. The scope of the review, and the challenge our transmission system must meet, evolved significantly as theoretical planning exercises transitioned to accounting for the specifics (in size and location) of concrete generation projects. As a result, changes to Public Service's generation system driven by this 2021 ERP & CEP have resulted in higher-than-expected transmission needs in the Denver metro area, as well as the identification of additional network upgrades within the San Luis Valley.

The Company's transmission network is most complex in the Denver metro area due to the concentrated amount of load in and around the region. There are many connections among the different substations which provide reliability and support in the event of a transmission line outages. The step down or conversion to lower voltages that occurs at these substations is a critical element in how the transmission network provides service to our customers. The lower voltage network within the Denver metro area is fed from the Company's higher voltage network that is primarily responsible for delivering electricity from the Company's large-scale generators and remotely located renewable resources. As power is imported into the Denver metro area, this energy is largely moved on the higher voltage 230 kilovolt ("kV") system under normal system operations. However, under contingencies caused by transmission facility outages, that flow seeks a new path to the load and in some cases causes overloads on the underlying lower voltage system or on the transformers that link these systems. The interconnectivity of these systems increases the reliability and resilience of the transmission system as a whole, but also increases the vulnerability of the 115 kV system to overloads under standard planning assumptions and requires the expansion of those facilities to maintain that reliable and resilient operation.

The Denver metro area is no stranger to growth—in fact, the Denver metro area's population growth rate has consistently outpaced the national rate in every decade since the 1930s.[75] Colorado's economic environment, as well as the region's steady population growth, is dependent on the continued availability of a robust electric system capable of providing customers with affordable, reliable, and clean electricity. However, this growth also creates challenges for developing the infrastructure necessary to provide that service to our customers as the availability of land suitable for transmission facilities dwindle and property costs increase. Public Service's existing transmission system is capable of reliably serving our customers today, but the energy transition cannot be accomplished with only minor changes to the transmission system.

These needs are compounded by two other dynamics driving the transmission investment needed to facilitate the Preferred Plan or any of the others plans presented in this Report. First, the scale and location of new generation that the Company is

[75] https://www.metrodenver.org/regional-data/demographics/population

acquiring in the Preferred Plan (and other plans) results in increasing levels of load that is served by generation located in remote areas. Second, the level of investment is significantly influenced by the lack of cost-effective bids in the Denver metro area in the Phase II competitive solicitation. More specifically, planned generation retirements, discussed in Section 5.1 above, combined with the lack of bids for new or existing generation located within the Denver metro area transmission constraint, did not allow for the selection of resources within the Denver metro area to replace the departing generation. New projects within the Denver metro area constraint would have reduced the magnitude of transmission system work within the Denver metro area; however, projects did not materialize.

Building on that dynamic, as the location of electric generation sources change from within the Denver metro area to outside of it, the transmission system will see significant changes in its power flows, even to the extent that predominant flows may change. Because transmission planning cannot be conducted with perfect foresight of the evolution of the electric system, the Company's transmission system was not designed to meet these types of conditions.

This Phase II transmission portfolio resolves the challenges that arise in implementing the Preferred Plan by alleviating the constraints that arose from the natural progression of system expansion and generation changes. The Company's selection of Bid 0989, as discussed in Section 2.6, provides value to the transmission system in addressing Denver metro area constraint issues, but the overall reduction in generation resources within the Denver metro area is a significant driver of the transmission projects identified by the Company's analysis.

Our Preferred Plan cannot meet its goals without the right infrastructure in place. The CPP was the first step in this direction, and with this Phase II Transmission Report we identify the additional investments necessary to enable the full portfolio. Based on the Company's review of transmission needs in this Phase II process, many of our existing substations lack the space for expansions necessary to eliminate overloads and expand the system's capacity. While the Company's transmission portfolio maximizes the capabilities of our existing facilities through projects such as transmission line reconductoring, the Company has nevertheless identified significant needs for new substations and new transmission lines. Moreover, siting, permitting, and the need for extensive undergrounding in the Denver metro area add cost and complexity to many of the network upgrade projects we have identified. In recognition of current siting and construction challenges within the Denver metro area, our approach to transmission planning creates value for customers by ensuring long-life transmission assets are built with a reasonable eye toward the future—these projects not only enable the Preferred Plan but are designed to accommodate future renewable development and growth in electricity demand.

While the scope of needed projects has grown beyond what was anticipated in the preliminary Phase I transmission analysis, the cost estimates in this Report have also been affected by unexpected macroeconomic trends that have sharply increased the costs and decreased the availability of the materials and labor necessary to construct transmission projects since the Company initially filed the 2021 ERP & CEP.

The Company does not expect that there are simple solutions to many of the constraints identified in the Denver metro area, but the scale of the challenge could potentially result in competitive advantages for the deployment of advanced technologies as transmission solutions. The Company's study refinements will fully evaluate the appropriate alternative projects and technologies to gauge whether they can be implemented on Public Service's system and to ensure that the portfolio we construct delivers the value of the Preferred Plan to our customers in the most cost-efficient manner.

6.4 Conclusion

As the Commission previously recognized in Decision No. C22-0559, Public Service "has little time prior to the 120-Day Report to definitively capture the projected transmission requirements for the various portfolios."[76] Accordingly, the Commission directed the Company to "provide in the 120-Day Report transmission cost estimates at a similar level of specificity as the Company provided in the 120-Day Report for the 2016 ERP process," while also recognizing that Public Service "will likely need additive transmission studies after Phase II concludes to determine the full extent of the transmission investment necessary to implement a portfolio."[77] The Company approached its Phase II transmission analysis with the equally important objectives of continuous improvement through implementing our learnings from past ERPs and transmission planning efforts and transparently explaining our findings. The Company will continue to hone its transmission analysis and cost estimates. These estimates do not rise to the level of confidence that the Company typically provides in CPCN applications, though the process improvements and diligence we put into this Phase II transmission analysis has nonetheless increased our level of confidence in these cost estimates compared to previous ERPs.

The Company's strategic vision for the CPP created significant value by creating a transmission backbone on Colorado's eastern plans to enable the Preferred Plan, but as we indicated in both Phase I and the CPP proceeding, more investment in transmission is necessary to deliver the value of the Preferred Plan to our customers. Through the analysis discussed in the Phase II Transmission Report, the Company has developed its transmission project plan to prioritize transmission projects as they are needed to resolve system constraints. However, given the scope of the Company's identified transmission projects needed to build out the robust system for the future of

[76] Decision No. C22-0559, at ¶ 95.
[77] Decision No. C22-0559, at ¶ 95.

delivering clean energy, all of the transmission required cannot reasonably be deployed within the same timeframe as the generation resources in the Preferred Plan. The Company will maintain reliable service for customers as the transmission portfolio is constructed using operational tools such as generator curtailment and redispatch. The expeditious development of this transmission portfolio will allow the Company and our customers to realize the full value of the Preferred Plan.

Through the analysis conducted in support of this Phase II process, the Company has developed a transmission portfolio that: (1) will alleviate transmission congestion allowing for our customers to receive the full benefit of the Preferred Plan, and (2) the Company can effectively implement as planned through its expertise in transmission project management. The Company has implemented robust project management processes described in the Phase II Transmission Report that will be applied to the development, monitoring, and control of project scope, estimates/budget, schedule, and risk management to prudently implement these transmission investments.

7.0 Section 123 Resources

This Section 7 discusses the bids that claimed Section 123 resource status and the Company's evaluation of these bids. Of the 1,073 individual projects bid into the 2022 All-Source Solicitation, six projects claimed Section 123 status. However, only five of the total number of projects that claimed Section 123 status meet the criteria established by Paragraph 501 of the Commission's Phase I Decision. Section 123 claims were received from gas, biomass, and storage generation technology types. Regardless of whether a bid qualifies for Section 123 status or not, it was evaluated in the Phase II bid evaluation process. The details of these bids were discussed in Section 3 of the Company's 30-Day Report filed on March 31, 2023.

7.1 Regulatory Background

Section 40-2-123, C.R.S., requires the Commission give the fullest possible consideration to the cost-effective implementation of new energy technology or demonstration projects. In an ERP context, the Commission defines such projects as "Section 123 Resources" as set forth in Rule 4 CCR 723-3-3602(q). In Paragraph 493 of its Phase I Decision in this Proceeding, the Commission referenced Decision No. C13-0094, in which the Commission held that a Section 123 Resource must be both new and clean pursuant to the statute and defined the terms "new" and "clean" as follows:

> A new project shall either: (1) incorporate one or more technologies, representing a substantial portion of its overall installed cost, that have not been regularly commercially demonstrated, up to the point in time that the resource is formally bid, or if not bid, acquired; or (2) be a project used to demonstrate the feasibility of a technology not before implemented in its proposed configuration. 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.[78]

In Phase I of this 2021 ERP & CEP Proceeding, Public Service suggested that the Commission focus on the requirement that Section 123 resources be "new" and specifically that a new technology is one that incorporates "technologies… that have not been regularly commercially demonstrated." The Company further suggested this would specifically "not include any standalone wind, solar, or lithium-ion based battery storage of any duration and any combination of those technologies together with other

[78] Consolidated Proceeding Nos. 11A-869E, 12A-782E, and 12A-785E, Decision No. C13-0094, p. 34 (mailed January 24, 2013) (footnote 41 omitted).

resources (*e.g.*, combined solar and wind projects, and solar and wind hybrids)" as these technology combinations are well commercialized and would provide negligible innovation benefits.[79]

In Phase I, Public Service reiterated that Commission clarity on the issue of determining Section 123 resources is necessary and pointed to the Company's 2017 All-Source Solicitation where it received 72 bids claiming Section 123 status and all but two of those included wind, solar, or short-duration battery storage. The Company offered an illustrative list of technologies that it contends merit Section 123 status, including:

> • Long-duration (10 hours or more) storage that can be held in a fully charged state for multiple days without losses or negatively impacting the short and long-term operating characteristics. Flow batteries or similar technologies would likely meet such a definition; and
>
> • Dispatchable generation projects employing low or no carbon-containing fuels on a firm supply basis.[80]

In Phase I, the Company also offered two options (Option A and Option B) by which Section 123 resources could move forward to computer modeling in the Phase II process. In Option A, Public Service proposed to rank eligible Section 123 bids by technology and cost, and lock one or two lowest-cost resources into the EnCompass model for re-optimization and let them "compete" for placement in the preferred portfolio. In Option B, the Company proposed to identify Section 123 bids below a MW level cap (*e.g.,* 20 MWs), sort and rank them, and add each least-cost bid by technology directly to the Company's preferred portfolio without re-optimization. Under this option, compliant Section 123 bids would simply be added to the Company's preferred portfolio with the added costs and impacts isolated for Commission consideration.

Commission'*s Directives on Evaluating Section 123 Resources*

In Paragraph 501 of its Phase I Decision, the Commission adopted the criteria Public Service suggested in Phase I regarding Section 123 resource determination. Specifically, the Commission stated that Section 123 resources must be new, innovative, not commercialized technology, and provide unique, scalable and beneficiation attributes as to future costs, emissions reduction, or reliability benefits. In addition, the Commission stated that standalone wind, solar, or lithium-ion based battery storage of any duration and any combination of those technologies together with other resources are not Section 123 Resources.[81]

[79] Hrg. Exhibit 130 (Scholl Rebuttal), pp. 63-64.
[80] *Id.* at p. 66.
[81] *See* Decision No. C22-0459, at ¶501.

In Paragraph 502 of its Phase I Decision, the Commission directed the Company to apply the Company's proposed Option A in which it will rank Section 123 bids by technology and cost and forward them to EnCompass modeling for portfolio re-optimization and presentation in the 120-Day Report with the least-cost Section 123 bids by technology "locked in."[82]

7.2 Section 123 Bid Discussion

The original intent of Option A for Section 123 bid analysis assumed that there would be multiple bids per generation technology that could qualify for Section 123 status. As there were only five Section 123 bids eligible for modeling, there was no need to rank lowest cost bids within technology types and have the top choices compete for placement in the Preferred Plan. While the hydrogen fuel cell and [redacted] bids could both be categorized as long duration storage, they are technologies that are so distinct that they were given individual EnCompass runs instead of directly competing with one another.

Another assumption was that the Preferred Plan would not include a Section 123 bid, and so the Company would "lock in" a Section 123 resource and reoptimize the plan to determine the cost impacts to the Preferred Plan if a Section 123 resource was included. However, for the reasons discussed in Section 2.5, the Company included the Hayden biomass project in the Preferred Plan. This means that in order to complete the review of Section 123 resources, the Company reoptimized the Preferred Plan with the biomass project removed. This provided a reference case to then compare the impacts of adding the other Section 123 resources individually. Table 36 shows the comparison of the Preferred Plan and the plan optimized after removing the biomass project. For the rest of this discussion, this portfolio will be referred to as Section 123 E.

[82] *See* Decision No. C22-0459, at ¶502.

Table 36 - Comparison of Preferred Plan and Section 123 E

Portfolios' Comparison of Key Characteristics

	1 - Preferred Plan (SCC)	12 - Section 123 E Biomass (SCC)
Nameplate Capacity (MW)		
Biomass	19	-
Gas	628	647
Solar	1,969	2,169
Storage	1,170	1,170
Wind	3,406	3,406
TOTAL Nameplate Additions (MW)	7,192	7,392
Flexible Capacity (MW)	1,817	1,817
Colorado Power Pathway (CPP) Trx Utilization (MW)	4,411	4,611
CPP May Valley-Longhorn Extension Trx Utilization (MW)	1,206	1,206
Accredited Capacity (MW)	1,621	Not Modeled
Section 123 Capacity (MW)	19	-
Owned Capacity (MW)	4,787	4,568
Owned Capacity (%)	66.6%	61.8%
Owned Energy (%)	69.7%	67.3%
Accredited Capacity Position		
2028 Capacity Position Long/(Short) (MW)	100	Not Modeled
2028 Actual Reserve Margin (%)	19.7%	Not Modeled
Planning Period Present Value Revenue Requirement (PVRR) ($M)		
NPV Base Portfolio Costs ($M)	$ 41,708	$ 41,450
NPV Trx PO-PF Interconnection Costs ($M)	$ 130	$ 132
NPV Trx Network Upgrades for Delivery ($M)	$ 2,353	$ 2,353
TOTAL PVRR ($M)	$ 44,191	$ 43,934
PVRR Delta vs. Preferred Plan ($M)	$ -	$ (257)
Emissions		
2023-2030 CO2 (M Tons)	69,322,272	69,216,473
2023-2055 CO2 (M Tons)	93,063,889	92,564,388
2023-2055 CO2 Delta vs. Preferred Plan (M Tons)	-	(499,501)
2030 CO2 Reduction from 2005 (%)	-87.4%	-87.5%
2023-2055 NPV CO2 at SCC ($M)	$ 6,288	$ 6,261
2023-2055 NPV Methane at SCM ($M)	$ 57	$ 56
TOTAL Present Value Societal Cost (PVSC) ($M)	$ 50,535	$ 50,251
PVSC Delta vs. Preferred Plan ($M)	$ -	$ (285)
Other		
2023-2055 Natural Gas Burn (MMBtu)	648,263,108	640,717,763
2028 Renewable Energy MWh (%)	83.0%	83.2%

While maintaining the generation type capacity minimums and model constraints of the Preferred Plan, the optimization of Portfolio Section 123 E makes up for the removed biomass capacity by exchanging one of the two combustion turbines found in Bid 1000 for an extra 19 MW of nameplate capacity in Bid 0235. There is also a 200 MW increase in solar resources, which is likely a result of the impact of the SCC on economic dispatch, as the model replaced the carbon-free energy served by the biomass plant which runs at above an 80% capacity factor in the Preferred Plan. Portfolio Section 123 E is the reference from which the other Section 123 resources are evaluated.

Only one Section 123 resource is selected as an option in any other primary portfolio presented in this report, with the [redacted] included in the $0CO2 Preferred Plan ($0C02) and alternative versions of that plan. This indicates that the Section 123 resources are typically not part of the optimal economic solution. However, the purpose of Section 123 is to promote the development of technology that may become part of the system in the future, beyond only economic considerations. Therefore, the following discussion will address potential benefits and risks of each resource and include a comparison table to the Section 123 E portfolio for the Commission to consider the impact of adding a Section 123 resource to the final portfolio.

[redacted]

As discussed in Section 5.4, Bid 0011 is a [redacted] technology that is attractive for its ability to dispatch now on a variety of clean fuels, including 100% Hydrogen or Ammonia. It is also able to swap fuels without interruption, which ultimately provides the Company flexibility in how it would prefer to dispatch the units, or how it might need to dispatch the units based on what fuels are available. These units can also meet the needs of a rapidly changing environment because they are capable of fast ramp rates, [redacted] The project is also located in the San Luis Valley, which is a strategic location for placing firm dispatchable generation. Another benefit is the scalability of the technology. The plant is comprised of blocks of [redacted] Finally, this technology is beginning to be adopted in the industry and has demonstrated success on smaller scales, meaning it is one of the more mature Section 123 projects being considered in this RFP. As the plant design and implementation is more straightforward than some of the other Section 123 resources, bringing it to utility scale for the Public Service system carries less construction and development risk as well.

While the Company finds these characteristics attractive, there are certain factors that raise the question as to whether this is the optimal setting for this bid. First, the Alamosa site proposed does not have firm gas supply, and therefore requires secondary fuel storage for reliability. As the [redacted] does not run on liquid fuel oil, this bid cannot take advantage of fuel oil storage at Alamosa, and so it incurs the costs of constructing onsite fuel storage. The clean fuels market is still developing, and this would likely lead to developing a type of natural gas storage onsite (the Company estimated costs for LNG storage in evaluating the bid) to ensure reliability today, and therefore does not leverage one of the bid's most attractive features. The bid also reports [redacted] For comparison, the other gas thermal generation proposed in this RFP only sees [redacted] from winter to summer operation. When comparing this bid to competition in the San Luis Valley, the difference in capacity between Bid 0011 and Bid 0986 [redacted] Table 37 below provides a comparison of Section 123 E and Section 123 A.

Table 37 - Comparison of Section 123 E and Section 123 A

Portfolios' Comparison of Key Characteristics	12 - Section 123 E Biomass (SCC)	[redacted]
Nameplate Capacity (MW)		
Biomass	-	-
Gas	647	650
Solar	2,169	2,369
Storage	1,170	1,170
Wind	3,406	3,406
TOTAL Nameplate Additions (MW)	7,392	7,594
Flexible Capacity (MW)	1,817	1,820
Colorado Power Pathway (CPP) Trx Utilization (MW)	4,611	4,611
CPP May Valley-Longhorn Extension Trx Utilization (MW)	1,206	1,206
Accredited Capacity (MW)	Not Modeled	Not Modeled
Section 123 Capacity (MW)	-	50
Owned Capacity (MW)	4,568	4,789
Owned Capacity (%)	61.8%	63.1%
Owned Energy (%)	67.3%	66.2%
Accredited Capacity Position		
2028 Capacity Position Long/(Short) (MW)	Not Modeled	Not Modeled
2028 Actual Reserve Margin (%)	Not Modeled	Not Modeled
Planning Period Present Value Revenue Requirement (PVRR) ($M)		
NPV Base Portfolio Costs ($M)	$ 41,450	$ 41,493
NPV Trx PO-PF Interconnection Costs ($M)	$ 132	$ 146
NPV Trx Network Upgrades for Delivery ($M)	$ 2,353	$ 2,353
TOTAL PVRR ($M)	$ 43,934	$ 43,991
PVRR Delta vs. Section 123 E ($M)	$ -	$ 57
Emissions		
2023-2030 CO2 (M Tons)	69,216,473	69,043,631
2023-2055 CO2 (M Tons)	92,564,388	91,641,280
2023-2055 CO2 Delta vs. Section 123 E (M Tons)	-	(923,108)
2030 CO2 Reduction from 2005 (%)	-87.5%	-87.7%
2023-2055 NPV CO2 at SCC ($M)	$ 6,261	$ 6,210
2023-2055 NPV Methane at SCM ($M)	$ 56	$ 55
TOTAL Present Value Societal Cost (PVSC) ($M)	$ 50,251	$ 50,257
PVSC Delta vs. Section 123 E ($M)	$ -	$ 6
Other		
2023-2055 Natural Gas Burn (MMBtu)	640,717,763	627,193,871
2028 Renewable Energy MWh (%)	83.2%	83.5%

<u>Hydrogen Fuel Cell</u>

Bid 0106 is a hydrogen based long duration storage project located outside of Brush, Colorado. The project is co-located with Bid 0044 and 0045 and features a [redacted]

When evaluating this project, there are certainly benefits that the Commission should consider. First, as discussed in Section 3.5, the increasing penetration of 2- to 4-hour battery storage is creating significant downward pressure on the marginal ELCC of further incremental storage. As the hourly load curves continue to flatten, energy limited resources are required to cover more and more hours for equal capacity credit, which is why 2 and 4-hour storage ELCCs diminish. A long duration storage project like Bid 0106 could be part of the solution to that problem, gaining a much higher capacity credit as it can stretch out the benefit of stored energy for much longer periods of time. Effective long duration storage is very attractive to the Company and meets one of the sought-out characteristics of Section 123 resources in this RFP.

Second, this project pairs the production of clean fuels with utility scale generation that would have synergy with the Company's future plans. As discussed in Section 5, clean fuels will be instrumental in unlocking the potential of gas thermal generation to be part of the clean energy future. A strategic partnership with [redacted] would help the growth and development of hydrogen production in the industry. The [redacted] so there may be an opportunity to begin developing a clean fuels pipeline to the Company's thermal units, opening the door to test gas fleet operations on clean fuel blends.

Finally, there could be technical value in demonstrating the application of fuel cells in power generation. The proposed project partners with [redacted] to leverage well established fuel cell technology that could demonstrate higher efficiencies than combustion turbine operations, which interests the Company. There could be a tradeoff between efficiency, capacity, and the cost of a premium fuel worth studying on utility scale.

After considering the benefits of this project, the Company acknowledges there are perceived development risks that make it difficult for this project's inclusion in the Preferred Plan. First, while the pricing of the bid is certainly attractive and cost competitive with more traditional forms of storage bid into this RFP, there are two factors that could present economic risk to the project. The production of more hydrogen than storage capacity coupled with the low $/MWh energy price of the bid indicates that the bidder may be relying on a developing market for hydrogen sales to make profits. If they cannot develop a market for their product, the Company is unsure if they would be able to maintain the pricing of their bid. Adding risk to the pricing and economics of the bid is the uncertainty surrounding the tax benefit the project could receive. The PPA provides that the Company would be responsible for providing the project with renewable power for purposes of receiving the 45V Hydrogen Production Tax Credit under the IRA. However, the IRS has yet to produce official guidance on how to calculate the carbon intensity of electrolysis-based hydrogen, which puts the pricing as presented in the bid at risk. The Company also does not currently have a way to ensure 100% renewable energy is used to support the project. Table 38 below provides a comparison of Section 123 E and Section 123 B.

Table 38 - Comparison of Section 123 E and Section 123 B

Portfolios' Comparison of Key Characteristics

Nameplate Capacity (MW)		12 - Section 123 E Biomass (SCC)		12 - Section 123 B Hydrogen Fuel Cell (SCC)
Biomass		-		-
Gas		647		628
Solar		2,169		2,369
Storage		1,170		1,218
Wind		3,406		3,406
TOTAL Nameplate Additions (MW)		7,392		7,621
Flexible Capacity (MW)		1,817		1,846
Colorado Power Pathway (CPP) Trx Utilization (MW)		4,611		4,659
CPP May Valley-Longhorn Extension Trx Utilization (MW)		1,206		1,206
Accredited Capacity (MW)		Not Modeled		Not Modeled
Section 123 Capacity (MW)		-		48
Owned Capacity (MW)		4,568		4,768
Owned Capacity (%)		61.8%		62.6%
Owned Energy (%)		67.3%		66.2%
Accredited Capacity Position				
2028 Capacity Position Long/(Short) (MW)		Not Modeled		Not Modeled
2028 Actual Reserve Margin (%)		Not Modeled		Not Modeled
Planning Period Present Value Revenue Requirement (PVRR) ($M)				
NPV Base Portfolio Costs ($M)	$	41,450	$	41,470
NPV Trx PO-PF Interconnection Costs ($M)	$	132	$	135
NPV Trx Network Upgrades for Delivery ($M)	$	2,353	$	2,353
TOTAL PVRR ($M)	$	43,934	$	43,958
PVRR Delta vs. Section 123 E ($M)	$	-	$	23
Emissions				
2023-2030 CO2 (M Tons)		69,216,473		68,962,029
2023-2055 CO2 (M Tons)		92,564,388		91,322,663
2023-2055 CO2 Delta vs. Section 123 E (M Tons)		-		(1,241,725)
2030 CO2 Reduction from 2005 (%)		-87.5%		-87.8%
2023-2055 NPV CO2 at SCC ($M)	$	6,261	$	6,193
2023-2055 NPV Methane at SCM ($M)	$	56	$	54
TOTAL Present Value Societal Cost (PVSC) ($M)	$	50,251	$	50,205
PVSC Delta vs. Section 123 E ($M)	$	-	$	(46)
Other				
2023-2055 Natural Gas Burn (MMBtu)		640,717,763		621,900,224
2028 Renewable Energy MWh (%)		83.2%		83.5%

[redacted]

Bid 0269 proposes a process improvement to typical [redacted] that helps it qualify for Section 123 status. [redacted] has proposed an [redacted] The project is located in Morgan County, in an area that was originally part of the Windy Hill project, which was intended to develop four salt storage caverns for natural gas storage. While that project was never constructed, [redacted] intends to use the known favorable geology to develop salt storage caverns to be used for clean energy.

This project is the only other long duration storage bid that was received in this RFP, and as such, should receive consideration for the benefits of 10-hour storage described in the previous section on the hydrogen fuel cell project. Should the technology work as proposed, it would provide the Company with 10 hours of clean dispatchable generation that would be straightforward to "recharge" [redacted] If selected, the project would also help to demonstrate [redacted] on a utility scale. There is a growing interest in [redacted] due to its potential to be deployed at retiring thermal generation facilities to take advantage of existing infrastructure for power generation. [redacted] Further demonstration of their technology could help promote beneficial reuse of retiring infrastructure in the future. This project is also cost competitive with other storage projects due to the nature of its design. While the upfront capital cost to develop the [redacted] is higher than battery storage, the LCC is competitive because of the amount of energy storage available compared to typical 2- and 4-hour storage. While it would also have similar capital-intensive components to a CT, the ongoing cost of fuel for combustion is removed, as this technology is driven by [redacted] In theory, the [redacted] is also scalable, as [redacted] increasing storage duration from 10 hours to 12 hours. In addition, [redacted] has stated that the entire size of the project could be expanded [redacted] should the Company want to pursue that option.

However, there are inherent risks that should also be considered. Although the project wisely considered the partners responsible for each technology, e.g., experience in salt cavern development, in [redacted] development, etc., the organization of the project has major components that all have to come together in a tight development window (project proposes end of 2026 COD). With so many moving parts, the risk that the project is developed to the capacity and specifications of the bid exists. Furthermore, [redacted] scaling to 150 or 300 MW [redacted] introduces even more risk. The viability of this project hinges on the ability to [redacted] If that step is not accomplished, then the benefit of [redacted] could be lost. It is not necessarily the Company's position that this cannot be done, or that the project will not meet its specifications, but the Company sees inherent risk to the deliverable capacity and commercial deadlines that would be agreed to in negotiations. Table 39 below provides a comparison of Section 123 E and Section 123 C.

Table 39 - Comparison of Section 123 E and Section 123 C

Portfolios' Comparison of Key Characteristics

Nameplate Capacity (MW)	12 - Section 123 E Biomass (SCC)	[redacted]
Biomass	-	-
Gas	647	628
Solar	2,169	2,169
Storage	1,170	1,320
Wind	3,406	3,406
TOTAL Nameplate Additions (MW)	7,392	7,523
Flexible Capacity (MW)	1,817	1,948
Colorado Power Pathway (CPP) Trx Utilization (MW)	4,611	4,411
CPP May Valley-Longhorn Extension Trx Utilization (MW)	1,206	1,206
Accredited Capacity (MW)	Not Modeled	Not Modeled
Section 123 Capacity (MW)	-	150
Owned Capacity (MW)	4,568	4,768
Owned Capacity (%)	61.8%	63.4%
Owned Energy (%)	67.3%	67.8%
Accredited Capacity Position		
2028 Capacity Position Long/(Short) (MW)	Not Modeled	Not Modeled
2028 Actual Reserve Margin (%)	Not Modeled	Not Modeled
Planning Period Present Value Revenue Requirement (PVRR) ($M)		
NPV Base Portfolio Costs ($M)	$ 41,450	$ 41,505
NPV Trx PO-PF Interconnection Costs ($M)	$ 132	$ 132
NPV Trx Network Upgrades for Delivery ($M)	$ 2,353	$ 2,353
TOTAL PVRR ($M)	$ 43,934	$ 43,990
PVRR Delta vs. Section 123 E ($M)	$ -	$ 55
Emissions		
2023-2030 CO2 (M Tons)	69,216,473	68,902,722
2023-2055 CO2 (M Tons)	92,564,388	91,449,029
2023-2055 CO2 Delta vs. Section 123 E (M Tons)	-	(1,115,359)
2030 CO2 Reduction from 2005 (%)	-87.5%	-87.8%
2023-2055 NPV CO2 at SCC ($M)	$ 6,261	$ 6,198
2023-2055 NPV Methane at SCM ($M)	$ 56	$ 54
TOTAL Present Value Societal Cost (PVSC) ($M)	$ 50,251	$ 50,242
PVSC Delta vs. Section 123 E ($M)	$ -	$ (9)
Other		
2023-2055 Natural Gas Burn (MMBtu)	640,717,763	621,555,682
2028 Renewable Energy MWh (%)	83.2%	83.1%

Geothermal

Bid 0552 is a next generation geothermal power plant located in Weld County. The project claims to be an improvement over traditional geothermal power applications in that it is able to mine the water found in Hot Sedimentary Aquifers ("HSA") that exist beneath oil and gas basins and are more abundant than natural hydrothermal systems (only about 2% of the earth's surface) that existing technologies have relied on. The project narrative claims that HSAs are globally abundant, and with the demonstration of their technology, the scalability problem of traditional geothermal can be solved. In this application, [redacted] has leveraged extensive knowledge of the Denver-Julesburg Basin to explore mining the hot (~135 degrees C), saline non-potable aquifer contained within a permeable sandstone formation. When brought to the surface, the heat is extracted and used in [redacted] he water is then reinjected back into the HSA.

As presented, this project supports Governor Polis' "Heat Beneath Our Feet" initiative, and the successful demonstration of this technology could harness a large resource found in the Denver-Julesburg basin, the largest oil and gas formation in the state. The resource would be firm dispatchable generation, as the power produced from the facility would not be weather dependent like wind or solar generation, or energy limited as in the case of battery storage. It would simply depend on the plant's ability to mine the water from the HSA, extract heat, and operate the [redacted] For reference, the bid currently proposes a 5 MW plant at [redacted]

While the bid states that the technology is both economical and scalable, the specific proposal is for 5 MW priced at [redacted] This creates cost challenges when compared toother resources the Company would utilize to supply the needs of the system during the RAP. Table 40 below provides a comparison of Section 123 E and Section 123 D.

Table 40 - Comparison of Section 123 E and Section 123 D

Portfolios' Comparison of Key Characteristics

Nameplate Capacity (MW)	12 - Section 123 E Biomass (SCC)	12 - Section 123 D Geothermal (SCC)
Geothermal	-	5
Gas	647	628
Solar	2,169	2,169
Storage	1,170	1,221
Wind	3,406	3,406
TOTAL Nameplate Additions (MW)	7,392	7,429
Flexible Capacity (MW)	1,817	1,854
Colorado Power Pathway (CPP) Trx Utilization (MW)	4,611	4,661
CPP May Valley-Longhorn Extension Trx Utilization (MW)	1,206	1,206
Accredited Capacity (MW)	Not Modeled	Not Modeled
Section 123 Capacity (MW)	-	5
Owned Capacity (MW)	4,568	4,768
Owned Capacity (%)	61.8%	64.2%
Owned Energy (%)	67.3%	67.7%
Accredited Capacity Position		
2028 Capacity Position Long/(Short) (MW)	Not Modeled	Not Modeled
2028 Actual Reserve Margin (%)	Not Modeled	Not Modeled
Planning Period Present Value Revenue Requirement (PVRR) ($M)		
NPV Base Portfolio Costs ($M)	$ 41,450	$ 41,528
NPV Trx PO-PF Interconnection Costs ($M)	$ 132	$ 144
NPV Trx Network Upgrades for Delivery ($M)	$ 2,353	$ 2,353
TOTAL PVRR ($M)	$ 43,934	$ 44,025
PVRR Delta vs. Section 123 E ($M)	$ -	$ 90
Emissions		
2023-2030 CO2 (M Tons)	69,216,473	69,170,745
2023-2055 CO2 (M Tons)	92,564,388	92,111,001
2023-2055 CO2 Delta vs. Section 123 E (M Tons)	-	(453,387)
2030 CO2 Reduction from 2005 (%)	-87.5%	-87.7%
2023-2055 NPV CO2 at SCC ($M)	$ 6,261	$ 6,237
2023-2055 NPV Methane at SCM ($M)	$ 56	$ 55
TOTAL Present Value Societal Cost (PVSC) ($M)	$ 50,251	$ 50,317
PVSC Delta vs. Section 123 E ($M)	$ -	$ 66
Other		
2023-2055 Natural Gas Burn (MMBtu)	640,717,763	633,771,137
2028 Renewable Energy MWh (%)	83.2%	83.3%

Summary

While comparison tables were provided in each individual technology section above comparing the Section 123 E reference to a reoptimized Preferred Plan that includes a specific resource, Table 41 below shows a comparison of each Section 123 portfolio side by side.

Table 41 - PVRR and CO2 Impacts of Each Section 123 Portfolio[83]

Bid_ID	Bidder	Project	Technology	Nameplate (MW)	Portfolio PVRR Delta vs. Section 123 E ($M)	Portfolio 2023-2055 CO2 Delta vs. Section 123 E (M Tons)
0011	[redacted]	[redacted]	[redacted]	49.5	$ 57	(923,108)
0106	[redacted]	[redacted]	[redacted]	48.0	$ 23	(1,241,725)
0269	[redacted]	[redacted]	[redacted]	150.0	$ 55	(1,115,359)
0552	[redacted]	[redacted]	[redacted]	5.0	$ 90	(453,387)

According to the EnCompass model, all portfolios in the above table would further reduce emissions from 2023-2055 on top of the other benefits discussed for each portfolio, reinforcing the concept that these projects could help advance progress towards the State’s clean energy targets and emissions reduction goals. However, when considering the total portfolio of resources available to the Company and the needs of the RAP, the Section 123 resources could not be placed in the Preferred Plan as an optimal solution.

For example, the technology proposed in Bid 0011 is certainly attractive, and would give the Company an asset that is ready to test dispatch on a variety of clean fuels. However, the exact application of this technology might not be the most ideal. It would be better if the project were located where firm gas was available so that extra capital expenditures would not be needed to operate in short term on natural gas while the clean fuels market develops. It could also be better suited to be strategically co-located with a clean fuels project such as an electrolyzer. Therefore, the Company would be interested to reconsider this technology further in a future RFP. For Bid 0552, the proposed capacity and price per megawatt hour seems to be most in conflict with the directive to consider the cost-effective implementation of developing technologies or demonstration projects.

In the case of Bid 0106 and Bid 0269, the Company believes there could be long term benefits to the system and to the industry if their projects are successful. However, with the risks previously discussed, the Company did not believe it to be prudent to depend on the successful development of both projects in the timeframe and at the bid price proposed in order to meet resource needs. If the Commission were to approve either of these projects *in addition to* the proposed Preferred Plan and without removing

[83] Comparison table does not include the biomass project, as it is already in the Preferred Plan.

resources needed for energy or capacity, the Company would be interested in proceeding in negotiations with both bidders for the purpose of developing their projects.

8.0 Pre-Construction Development Assets

In this Section, the Company discusses the PCDA concept and process that came out of Phase I and its relationship to the Company's contingency plan contemplated by ERP Rule 3609(c).

8.1 Background

In its Phase I Decision, the Commission acknowledged that the record in this Proceeding demonstrates an "unprecedented amount of uncertainty" as compared to prior ERPs. For example, the Commission noted that recent climate events suggest that history may not fully capture future climate extremes and the impact on peak demand and energy usage, and that the record in this Proceeding suggests that issues surrounding supply chain disruptions, inflation, rising interest rates, labor costs, and solar tariffs could further impact the ability to timely and cost-effectively bring new resources online. Moreover, core issues surrounding the future costs and performance of clean energy technologies—involving, for example, wind, solar, storage, electric vehicles, and air-source heat pumps—continue to create uncertainty during this ERP RAP as they have in the past.[84] The Commission went on to acknowledge that under the terms of the Updated Settlement Agreement, the parties addressed issues of uncertainty by, for example, presenting a more flexible ELCC approach for calculating intermittent resource capacity values, developing a process for dealing with changed circumstances, created an interim ERP approach through the Pueblo Just Transition Plan process that allows for accelerated between-ERP cycle resource acquisitions, among other issues.[85]

Notwithstanding various terms of the Updated Settlement Agreement approved by the Commission, the Commission found that some significant reliability and cost concerns remain. For instance, the Commission referenced hearing testimony of Company witness Mr. John Welch, that the CT development process could take at least 18 months to find a site, procure air quality permits and complete engineering designs, and another 16 months to construct and test a new CT. Given these timing realities, the Commission found that material risk remains that Public Service's system may need more capacity sooner because of extreme weather, extended unit unavailability, or an inability to build some of the CT resources selected out of Phase II of this proceeding and, it could take a year to run an acquisition process and at least three years to build additional CTs. The Commission also noted potential cost issues and uncertainties and referenced the hearing testimony of Company witness Ms. Alice Jackson regarding the

[84] Decision No. C22-0459, at ¶¶396-400.
[85] Decision No. C22-0459, at ¶¶401.

potential for significant near-term cost increases and delays due to solar tariff issues, supply chain, rising interest rates, general inflation, and increased labor costs.[86]

The Commission expressed concern that these price risks and uncertainties in current wind, solar, storage, and CT markets could potentially persist into 2023 in ways that may delay resource online dates and raise costs to Colorado customers; while at the same time, a portion of these increased costs and risks could potentially be avoided by waiting until markets settled, so long as system resilience is maintained, and the planned coal plant retirements are not delayed.

To help mitigate these near-term concerns and create optionality, the Commission requested the Company explore acquiring PCDAs for gas-fired resources[87] in a manner that would avoid building the projects now. Instead, the Company would finish development of these PCDAs over time and then potentially bid these projects into the all-source 2024 Pueblo Just Transition solicitation. Interim customer funding for these investments could occur through the Electric Commodity Adjustment ("ECA"), which would enable some Commission oversight in real time.

In its Phase I ARRR Decision, the Commission further clarified that: (1) Public Service may solicit proposals in Phase II and present any cost-effective options focused on gas-fired resources as part of its contingency plan required by Rule 3609(c) in the 120-Day Report; (2) because these are backup resources, any PCDAs acquired in Phase II of this Proceeding will not affect the Company's resource need in this Proceeding; (3) PCDAs included as part of contingency planning optionality would be brought back to the Commission for construction approval only if a qualifying event triggers the contingency plan; and (4) the in-service dates for these development assets must be within the acquisition period for this Proceeding's solicitation (i.e., through December 31, 2028) but could be as early as 2024 and how quickly a development asset could be brought online will be a factor the Commission considers when evaluating whether that particular PCDA bid is worthwhile.

8.2 PCDA Conferral and Process Overview

Decision No. C22-0559 directed the Company to confer with parties regarding the PCDA process and bring the results of that conferral back to the Commission prior to Phase II.[88] Accordingly, on October 28, 2022, the Company filed a notice of conferral outcomes ("Notice"), including an outline of the PCDA process supported by Settling Parties.[89] The PCDA process detailed in the Notice outlined the structure, general RFP

[86] Decision No. C22-0459, at ¶¶ 402-405.
[87] By Decision No. C22-0559, at ¶ 60, the Commission limited the optional PCDA process to gas-fired resources.
[88] ARRR Decision, at ¶ 61.
[89] The Company also offered and held multiple briefings for non-Settling Parties on the PCDA process.

requirements, project evaluation and 120-Day Report presentation, and project award aspects of the PCDA process. The PCDA process as outlined in the Notice is included in its entirety as Appendix G for reference and summarized below.

PCDA Structure and RFP Process

The PCDA process was structured through the RFPs with an option for bidders to check a box in the bid package and provide certain information to be eligible for PCDA treatment. Eligible natural gas fired PCDA projects may have in-service dates beginning in 2024 and through end of year 2028. The PCDA projects could be bid as variations on another bid (e.g., a PCDA version of a project bid for regular modeling treatment as a Company-owned project, build-own-transfer project, or PPA) and no separate bid fee was required. Bidders who chose the PCDA option were required to provide, in addition to a full bid package as required by the RFP: (1) milestone schedules for permitting and pre-development work to reach "shovel-ready" status, along with projected milestone payment levels; (2) the ISD and a discussion of the time frame for a project to achieve the ISD from "shovel-ready" if the contingency plan is triggered; (3) a narrative regarding how the bidder will confirm milestone achievement to the Company consistent with the proposed milestone schedule; and (4) for projects that would result in a PPA, IPP bidders must agree to hold the PPA rate through the end of 2028 and execute a binding term sheet with the Company.

PCDA Project Evaluation and 120-Day Report Presentation

From projects not included in the Preferred Portfolio(s), and selected by the bidder for PCDA eligibility, the conferral process contemplates that the Company will propose, to the extent practicable, three levels of projects for PCDA treatment in the 120-Day Report (low firm capacity, medium firm capacity, high firm capacity). The key considerations for PCDA selections will be accredited capacity and levelized cost of capacity, and the levels of firm capacity in each of the three levels outlined above will be determined based on PCDA interest. The Company agreed to provide estimates of the amounts of milestone payments that will be recovered through the ECA on an annual basis (e.g., for each year from 2023 to 2028), understanding that the actual recovery will be dependent upon milestone achievement and payment to any bidder in a given year. Parties may comment on the PCDA proposals through the Phase II notice and comment process and the Company may respond in its responsive comments. For projects included in portfolios other than the Preferred Portfolio, the Company will denote the projects that have self-selected for PCDA treatment.

PCDA Project Award

The Commission will review the list of projects proposed for PCDA treatment in this Report, as well as the projects not included in the Preferred Portfolio and back-up bids that have self-selected for PCDA treatment. The Commission will make a determination as to which projects are selected as PCDA projects in the Phase II Decision after reviewing the PCDA list, considering intervenor comments, selecting the final portfolio, and reviewing PCDA-eligible projects from the proposed back-up bids and non-selected portfolios. Bids may be PCDA eligible and selected as back-up bids. PCDA bids will not affect satisfaction of the firm resource need for any portfolio brought forward under the approved portfolio development framework. For purposes of the “safe harbor” demonstration under § 25-7-105(1)(e)(VIII)(C), C.R.S., the generic resource additions through December 31, 2030 would be used for purposes of a compliance demonstration as opposed to any approved PCDA bids. A binding term sheet will be executed for any PCDA bid approved in the Phase II Decision, with the exception of self-build PCDA projects. All bids and actions taken pursuant to projects selected and approved through as PCDA projects will be subject to Rule 3617(d). Successful PCDA bidders will receive milestone payments as achieved and not the PPA energy payment rate or other compensation for the project.

8.3 PCDA Proposals Received

For purposes of this Phase II competitive solicitation, only three IPP bids that advanced to portfolio development selected the PCDA option, as summarized in Table 42.[90]

Table 42 - Bids Selecting the PCDA Option

Bid ID	Project Name	Technology	Nameplate MW	Ownership Structure	In-Service
0011	[redacted]	[redacted]	49.5	Own	2026
0384	[redacted]	Combustion Turbine	612	PPA	2028
0392	[redacted]	Combustion Turbine	816	PPA	2028

8.4 PCDA Asset Discussion and Recommendation

The Company is not recommending any of these PCDA assets for Commission approval for several reasons. First, Bid 0011 is a newer technology type that is a Section 123 bid and does not appear to fit well with the intent of the PCDA process given the more nascent technology underlying the bid. Second, the size of the remaining two PPA bids, as well as the geographic location of these bids, render them difficult for the Company to recommend as PCDA assets with commensurate expenditures from the ECA. As noted earlier in this Report, while few bids selected the PCDA option in the bid package and no bids are being recommended by the Company as PCDA assets, the Company views this type of structure as a very positive step in

[90] The Company notes that a single bidder bid several ownership structure variations of the gas CT projects listed in Table 42 all of which selected the PCDA option; however, the Company has included in Table 42 only those bid variations that were advanced to computer-based modeling.

resource procurement and intends to consider proposing the PCDA process or a similar process in the forthcoming Pueblo Just Transition Plan solicitation. This type of structure could provide resource options in the event of a project failure or be used to procure projects with longer development timelines, and the Company appreciates the Commission's foresight in developing this process and looks forward to analyzing potential approaches in future planning cycles.

Finally, while the Company is not recommending approval of these PCDA bids as part of this Phase II process, the Company has provided the estimates of the annual milestone payments provided by the bidders in Highly Confidential Appendix H should the Commission choose to consider these bids and the PCDA structure further as part of this Phase II process.

9.0 Best Value Employment Metrics

Section 9.0 provides an overview of the statutory and regulatory framework regarding requirements for and evaluation of BVEM in the context of resource acquisition. This Section discusses the role of the labor economist and provides references to the BVEM scoring methodology and results.

9.1 Background and Regulatory Framework

BVEM received an additional review by the General Assembly in 2019 resulting in amendments to § 40-2-129, C.R.S., which establishes a framework that holds utilities and non-utility bidders to similar standards when it comes to providing BVEM information. Specifically, § 40-2-129, C.R.S. requires utilities to obtain (i.e., from bidders) and provide to the Commission the BVEM documentation in response to the four metrics, including:

> (I) the availability of training programs, including training through apprenticeship programs registered with the United States Department of Labor, Office of Apprenticeship and Training;
>
> (II) the employment of Colorado workers as compared to importation of out-of-state workers;
>
> (III) long-term career opportunities; and
>
> (IV) industry-standard wages, health care, and pension benefits.

When a utility proposes to construct new generation facilities of its own, the utility is required to provide similar information to the Commission. To ensure that the BVEM information provided by either a bidder or the utility is substantive, § 40-2-129, C.R.S. requires: (1) provision of the BVEM documentation; or (2) in the alternative, certification of compliance with objective BVEM performance standards set forth in the solicitation document. The Commission may waive the requirements of (1) and (2) where a PLA is utilized.

As discussed in Section 2.16 of Volume 2, Technical Appendix of the Company's Phase I filing, the Company explained that in Proceeding Nos. 17M-0694E (Repository Proceeding) and 19R-0096E (Comprehensive Rulemaking Proceeding), Public Service worked closely with Rocky Mountain Environmental Labor Coalition and Colorado Building and Construction Trades Council, AFL-CIO (jointly, "RMELC/CBCTC") regarding potential rule revisions that could improve the existing BVEM requirements given past disputes over the proper application of BVEM related rules. Specifically, the more detailed BVEM information requirements were reflected in Proposed Rule 3613 and to provide further detailed guidance to prospective bidders to assist them with providing detailed and robust BVEM information.

At the Commissioners' Weekly Meeting on March 24, 2021, the Commission discussed the rulemaking at length and decided to not adopt new rules as a result of the proceeding.[91] However, one of the items the Commission focused on in those deliberations was BVEM. The Commission stated that the more detailed BVEM-related provisions reflected in Proposed Rule 3613 will be required and that bidders should know that this information is necessary for their bids to be accepted. Additionally, the Commission stated that it expects the Company to include the more detailed BVEM requirements in its RFP documents. Accordingly, the Company included the more detailed BVEM information requirements in its RFP documents and indicated that the Company can and will disqualify bids that provide insufficient BVEM as part of the bid packages.

Consideration of BVEM and the Multi-Step Phase II Process

Consistent with Paragraph 69 of the Settlement Agreement approved by the Commission in its Phase I Decision,[92] the Company implemented a multi-step process in the Phase II bid evaluation to ensure consideration by the Commission of BVEM under § 40-2-129(1)(a), C.R.S. The multi-step process is generally summarized as follows:

- First, the RFP directed bidders to include quantitative information with bids regarding the four metrics detailed above. The RFP documents further noted that (1) if the contracts for the project which is bid are not yet completed, the bidders shall include the standards the bidders include in their requests for proposals to be issued to subcontractors related to these elements, and (2) to the extent that quantitative information cannot be provided for any of these categories, bidders were to explain why as part of their bid package.
- Second, as noted in the RFP, a bid that incorporates a Project Labor Agreement ("PLA") will automatically be considered to meet threshold BVEM standards.
- Third, the Company conducted an initial screen of BVEM provided and disqualified bids that did not provide sufficient BVEM, either as initially provided or following an opportunity to remedy the insufficiency, as set forth above as part of the bid package.
- Fourth, as discussed below, the Company retained a labor economist to assist in scoring bids for the BVEM provided.
- Finally, as part of its 120-Day Report, the Company will provide a cumulative BVEM score for each portfolio presented as part of the Commission-approved portfolio development framework. The cumulative BVEM score will be considered

[91] As of this writing, the Commission's written Decision is pending.
[92] Decision No. C22-0459, at ¶156.

by the Commission in its evaluation of bid portfolios, consistent with § 40-2-129(1)(a), C.R.S.

9.2 Role of the Labor Economist

In accordance with Paragraph 69 of the Settlement Agreement, the Company retained a labor economist to assist in scoring bids for the BVEM provided by bidders.[93] Following consultation with and support from labor organizations (i.e., the Rocky Mountain Environmental Labor Coalition ("RMELC"), Colorado Building Construction Trades Council ("CBCTC"), and IBEW Local 111), the Company contracted with the Leeds School of Business at the University of Colorado–Boulder ("CU Leeds") to act as the labor economist and perform the BVEM review and scoring tasks contemplated by the Settlement Agreement. Specifically, the role of CU Leeds in Phase II was to score the BVEM for all bids advanced to computer-based modeling. The team from CU Leeds participated in the bidders' conference held on December 20, 2022, where they presented to potential bidders the methodology and process for scoring BVEM information required as part of each eligible bid package. As discussed in more detail below, CU Leeds developed a scoring rubric that focuses on a macro-level perspective and avoids individual value judgements, is informed by BVEM regulation, and assumes the quality of BVEM information is higher with more detail.

<u>BVEM Scoring Methodology</u>

CU Leeds (i.e., the labor economist) evaluated bids by scoring the completeness and detail of four major categories proscribed by §40-2-129, C.R.S. noted above with discrete subcategories within each category as outlined in the BVEM guidelines in the RFP. To minimize the risk of subjectivity, CU Leeds undertook a literature review to identify best practices, reviewed projects in relation to similar projects, and considered the relevant detail provided within the BVEM guidelines. In its evaluation, CU Leeds avoided subjective determinations as to the value of BVEM reporting. Bidders received a score between 0 and 1 for each subcategory which was then averaged to develop major category scores which were then weighted to provide an overall score. Further detail is provided in Appendix I: BVEM Evaluation Rubric – Background, Design, and Implementation provided by CU Leeds.

<u>BVEM Scorecard and Documentation</u>

Consistent with Paragraph 60 of the Settlement Agreement, the Company has provided the BVEM scorecard developed by CU Leeds for each portfolio presented in this Report as Highly Confidential Appendix J for consideration by the Commission in its evaluation

[93] Costs of the labor economist will be recovered through the Electric Commodity Adjustment ("ECA") pursuant to Paragraph 69 of the Settlement Agreement and approved by Decision No. C22-0459, at ¶156.

of bid portfolios, consistent with § 40-2-129(1)(a), C.R.S. The cumulative BVEM scores for the primary portfolios presented in this Report are discussed in Section 2.6. Additionally, as required by Paragraph 157 of the Phase I Decision, the Company has provided the BVEM documentation as provided by bidders in response to the information required by the RFP as Highly Confidential Appendix K to enable the Commission to evaluate whether the final approved plan satisfies the requirements of § 40-2-129(1)(b) and (c), C.R.S. Finally, the Company developed the High PLA Portfolio consistent with the portfolio development framework in the Phase I Decision (see Section 4).

10.0 Workforce Transition and Community Assistance

Section 10.0 provides an overview of the Just Transition planning efforts the Company has and continues to engage in, including workforce transition and community assistance. This Section also provides a brief summary of key provisions of the Settlement Agreement approved by the Commission that establish substantial tax benefits for host communities and a regulatory framework for related future filings.

10.1 Background

As discussed throughout Phase I, Senate Bill 19-236 introduced workforce transition and community assistance requirements associated with accelerated coal retirements as part of the 2021 ERP & CEP process. In its Phase I Decision, the Commission approved provisions of the Settlement Agreement that: (1) provide substantial just transition benefits for the workers and communities that have supported the Hayden, Pawnee, and Comanche units over decades of service in the State of Colorado; and (2) establish a regulatory framework for related future filings, including the Pueblo Just Transition Plan solicitation and updated Just Transition Plans.[94]

Specifically, under the Just Transition Plan process established by the approved provisions of the Settlement Agreement, Routt County and Morgan County will receive six years of property tax payments post-retirement and post-conversion, respectively, unless offset by investment (e.g., new infrastructure, replacement generation) that provides tax base in these communities. Similarly, the Company commits to make payments to Pueblo County annually from 2031 through 2040 in the amount of the projected lost property tax revenues for those years, unless offset by property tax revenues from generation or transmission infrastructure sited at Comanche Station or within Pueblo County. Moreover, the Pueblo Just Transition Plan will involve a standalone competitive solicitation for the replacement of the energy and capacity associated with Comanche 3 in an effort to ensure benefits to the Pueblo community are the focus of the replacement portfolio, simultaneously seeking just transition benefits and the procurement of innovative technologies to help the Company progress towards a carbon-free future.

For purposes of this Phase II, pursuant to the terms of the Updated Settlement Agreement, the Company modeled just transition impacts (i.e., the potential future costs of both workforce transition plans and community assistance plans), consistent with the Company's Direct Case in Phase I by utilizing an escalating property tax-based proxy value that runs until the earlier of (1) a unit's original retirement date (for all units other than Comanche 3); or (2) December 31, 2040 (in the case of Comanche 3).

[94] Decision No. C22-0459, at ¶109.

Following the Commission’s Phase II Decision approving a final portfolio, the Company will file updated Just Transition Plans for Hayden, Pawnee and Comanche (see also Section 12.2 for anticipated filing timeframes). These Just Transition Plan filings will include updated workforce transition plan costs, community assistance costs, and any offsets to community assistance costs due to investments in the relevant community. These filings may also include a proposal for a cost recovery mechanism (if not already addressed in a rate case) for any Just Transition Plan costs, and future ERP cycles provide a forum for iteration on these plans as retirement dates get closer in time.

10.2 Workforce Transition

Xcel Energy, Inc. is an employer of choice among skilled workers in Colorado, providing a prevailing wage and benefits package, a safe and inclusive workplace, and apprenticeships and avenues to build and sustain a career with the Company. Based on feedback gathered from our coal plant workers, most workers prefer to stay within their community and retain a job within the Company beyond closure of the plant. We have a highly skilled workforce, and our objective is to retain these skilled workers, leverage their expertise across the organization, and help the Company as we move forward with our clean energy future.

The Company has a long and successful history of transitioning our workforce. Over the past 15 years we have closed 18 units across our service territory without any forced workforce reductions. We are committed to a transition of our workforce from coal and into clean energy jobs. Through our prescriptive methodology of workforce transition planning and guiding workers through the transition, we will identify skill and worker transition support gaps, create transition pathways, design and deploy training and other transition supports needed, and lead workers through the change.

The Company will leverage natural attrition and worker retirements to maintain appropriate staffing levels leading up to closure and beyond. The remaining workers will be up-skilled to operate and maintain the new clean energy assets, or if they choose relocated and/or transitioned and re-skilled into another job.

For example, the workers at the Hayden Station plant already hold approximately 80% (on average) of the skills needed to operate and maintain a biomass unit. Working closely with the biomass unit vendor, the Colorado Northwestern Community College (:CNCC”), the International Brotherhood of Electrical Workers Local 111 (“IBEW 111”) and building trade unions in the region, and the Council for Adult Experiential Learning (“CAEL”), we will identify the additional training needed to build, operate and maintain the unit. In partnership, this team will develop local and/or in-house training to transition the workforce. This also provides the community and the Company with the training needed to create a local talent pipeline to fill future attrition.

Another example is our Pawnee Station power plant scheduled to convert to a gas fired plant at the end of 2025. Employees at Pawnee will need to be re-skilled through development and deployment of on-the-job training to learn the new equipment and to update and follow new start up and operating procedures. At this time, we do not expect to transition any workers to a new job at another site, and all workers may remain at Pawnee. During and after the conversion, some workers would be repurposed and deployed at the Pawnee site to support system overhauls or maintenance outages, conversion related items, and to operate an adjacent facility.

Workers at Hayden, Pawnee, and Comanche may need transition supports beyond just training, which will be further explored, defined, and refined prior to closure when employee workforce transition conversations take place, pathways are established, and terms are negotiated with IBEW 111.

To further support our coal plant employees in advance of the transition, representatives from the Company's Executive team and workforce representatives have and will continue to visit the closing coal plants on a regular basis. Plant visits have taken place about every several months either as new information is made available about our filings or as we progress in meeting key milestones in building the foundation for a workforce and community transition. These plant visits are an essential part of the Company's transition commitment, are key components of our change management plans, are an opportunity to have open dialogue with our employees, provide regulatory and timeline updates, and discuss details of the plant conversion and/or retirement process.

The Company's Phase I filing included a workforce transition plan with worker programs, training, and cost estimates. As noted above, these cost estimates will be updated following the Commission's Phase II Decision and leading up to plant closures in future Just Transition Plan filings.

10.3 Just Transition Community Engagement

The Company has made community engagement a cornerstone of its clean energy transitions. Beginning with early decarbonization efforts with the Clean Air Clean Jobs Act, through the 2016 Electric Resource Plan and Colorado Energy Plan, to the current Clean Energy Plan, the Company makes engagement with its host communities and workforce a central focus of its planning efforts. Since the Company received approval of its Phase I ERP & CEP, we have continued to engage with the Hayden and Pueblo communities to explain our transition plans and the status of the Phase II competitive solicitation.

The Company's efforts in the Hayden community included several meetings with community groups prior to the filing of this 120-Day Report. Formal meetings include recurring engagements with the North West Colorado Advisory Council, Routt County

Commissioners, the Town of Hayden, Club 20,[95] and the Associated Governments of Northwestern Colorado. The meetings are not singularly dedicated to the Company resource(s) in the community and just transition planning but are a central focus as the impacts of these efforts have a significant impact on the financial health of the community because of the importance of taxes and jobs provided by Hayden station. Transparency and two-way communication are central principles to these engagements to ensure stakeholders are brought along with the process and understand the Company's work and timelines. The Company has also provided tours of the Hayden facility to some of these groups as well as the State's Attorney General, Yampa Valley Sustainability Council, Boettcher Foundation, and local Yampa Valley students and educators.

Our engagements in the Pueblo community have focused on our efforts to support the Pueblo Innovative Energy Solutions Advisory Committee ("PIESAC"), the formal name of the advisory committee convened to support the Company's community-based study of future generation and storage investments in the Pueblo area. The Company has held six meetings with PIESAC in 2023 with another five planned before the end of the year. In addition to these meetings, the Company has been publicly sharing all presentations and meeting information on a dedicated website[96] to allow interested stakeholders and community members to understand the status of PIESAC's efforts and plans. Stakeholders and community members can also ask questions or provide feedback by contacting the Company by phone or email. A final study is expected in December in preparation for the June 2024 Pueblo Just Transition Plan filing.

However, engagement in the Pueblo community is not limited to just PIESAC. The Company is planning several other engagement efforts in the fall of 2023. All engagements will include plain language materials accessible in both English and Spanish.

- *Interview sessions:* the Company will hold at least 15, one-hour interviews with state legislators, public health, labor, environmental justice organizations, local and regional governments, business and workforce development advocates, and education leadership.
- *Focus groups:* the Company will hold at least eight, two-hour groups sessions with organizations including environmental justice, business and workforce, labor, education, local governments, neighborhood leaders with a focus on disproportionately impacted communities; faith-based leaders; and other community-minded groups.

[95] https://club20.org
[96] https://co.my.xcelenergy.com/customersupport/s/projects/pueblo-energy-study

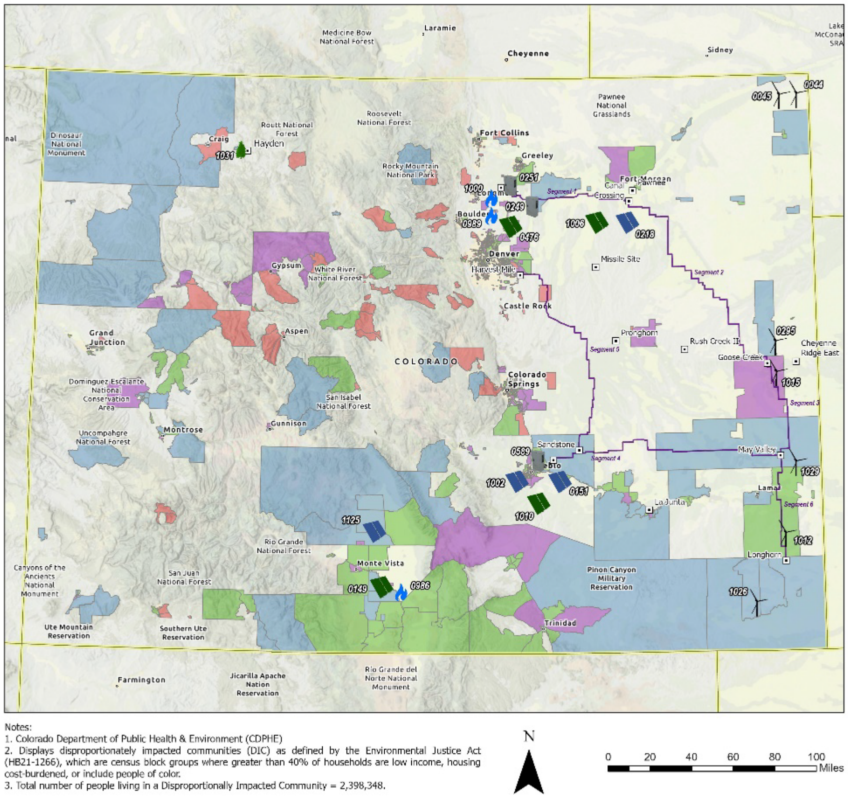
- *Open houses:* the Company will hold at least two open houses for residents of the Pueblo community to allow members to hear about the Company's clean energy transition plans, ask questions, and provide feedback.

Going forward, the Company will continue to engage with stakeholders in both communities as we approach the Pueblo Just Transition Plan and solicitation in 2024 and 2025 as well as the Hayden Just Transition Plan within 120 days of the final Phase II Decision, consistent with Paragraph 28 of the Settlement Agreement. We will continue looking for opportunities to bring clean energy jobs and economic growth to these, and other communities throughout the state, because the support of our communities is foundational to successfully achieving the clean energy transition.

10.4 Mapping of Bids in Disproportionately Impacted Communities

Pursuant to Paragraph 421 of the Phase I Decision, the Company has mapped bids included in a portfolio in this 120-Day Report against CDPHE's available mapping of disproportionately impacted communities ("DI Communities"). Three maps are provided in Appendix L and include the location of bids in relation to DI Communities as identified by CDPHE for: (1) bids included in the Preferred Plan (also shown in Figure 26 below); (2) back-up bids; and (3) bids included in all other portfolios.

Figure 26 – Map of Preferred Plan Bids and Disproportionately Impacted Communities



Notes:
1. Colorado Department of Public Health & Environment (CDPHE)
2. Displays disproportionately impacted communities (DIC) as defined by the Environmental Justice Act (HB21-1266), which are census block groups where greater than 40% of households are low income, housing cost-burdened, or include people of color.
3. Total number of people living in a Disproportionally Impacted Community = 2,398,348.

PSCo 2022 All-Source RFP Preferred Plan

Disproportionately Impacted Communities

Substation
Colorado's Power Pathway

CDPHE D.I. Community
- Housing Burden
- Low Income
- People of Color
- More than one category

Generation Type
- Biomass
- Gas
- Solar
- Solar + Storage
- Storage
- Wind

Bid ID	Gen Type	CDPHE D.I. Community Category
0044	Wind	Not Affected
0045	Wind	Not Affected
0149	Solar + Storage	Low Income
0151	Solar	Not Affected
0218	Solar	Not Affected
0249	Storage	Not Affected
0251	Storage	Not Affected
0295	Wind	Low Income
0476	Solar + Storage	Not Affected
0589	Storage	People of Color
0986	Gas	More than one
0989	Gas	Not Affected
1000	Gas	Not Affected
1002	Solar	Not Affected
1006	Solar + Storage	Not Affected
1010	Solar + Storage	More than one
1012	Wind	More than one
1015	Wind	People of Color
1026	Wind	Low Income
1029	Wind	Low Income
1031	Biomass	Not Affected
1125	Solar	Low Income

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11.0 Cost Recovery

This Section provides an overview of the treatment of cost recovery for retired coal plants, the planned use of the Colorado Energy Plan Rider ("CEPR"), a brief update on the Renewable Energy Standard Adjustment ("RESA"), and future cost considerations stemming from the negative effects of finance lease treatment and resulting imputed debt for certain PPAs.

11.1 Coal Asset Cost Recovery (Proceeding No. 22A-0515E)

In its Phase I Decision, the Commission adopted the retirement and conversion dates for all generating units as well as provisions concerning cost recovery for the early retirement of Comanche 3 without modification. However, the Commission concluded that the record on cost recovery associated with the early retirements of units Craig 2, Hayden 1, Hayden 2, and the retired coal portion of Pawnee was inadequate and ordered Public Service to address an appropriate cost recovery approach for these assets through a separate application[97] – a requirement Public Service fulfilled through its Application filed on November 16, 2022 in Proceeding No. 22A-0515E. Specifically, Paragraph 65 of the Commission's Phase I Decision ordered Public Service to "present the recovery of unamortized balances and decommissioning costs (with each cost separately quantified) at each of the coal plants using at least four different methods: regulatory asset approach, accelerated depreciation, financing at the long-term cost of debt, and securitization." The Commission's Phase I Decision also ordered the Company to address several key questions around securitization.

<u>Phase II Modeling Assumptions for Coal Cost Recovery</u>

The Settlement Agreement approved by Decision No. C23-0362 in Proceeding No. 22A-0515E established the Phase II modeling assumptions for cost recovery of retiring coal assets. Specifically, the Phase II modeling assumptions provide for the Company to recover remaining NBVs and decommissioning costs associated with the Craig Unit 2, Hayden Unit 1, and Hayden Unit 2 regulatory assets amortized over eight years from the retirement or conversion of each unit and earning a return at the Company's Commission-approved WACC while the retiring coal portion of Pawnee regulatory asset modeling will utilize a 12-year amortization period with a return at the Company's Commission-approved WACC. In addition, bundled securitization was assumed in the Phase II modeling of the Coal Regulatory Assets and Comanche 3, following the

[97] Decision No. C22-0459, ¶¶ 63-66.

retirement of Comanche 3 no later than January 1, 2031. These assumptions are to be used solely for modeling purposes, with actual and prudently incurred costs recovered through the cost recovery approach set forth in the Settlement Agreement approved in Proceeding No. 22A-0515E.

11.2 Colorado Energy Plan Revenue Rider ("CEPR")

The Company's Phase I ERP & CEP Direct Case included a proposal to recover the incremental costs of eligible energy resources with the Renewable Energy Standard Adjustment ("RESA") rider and the incremental cost of clean energy plan activities either exclusively with the CEPR rider or alternatively with a combination of the CEPR and RESA riders. The incremental costs of eligible energy resources recovered with the RESA were referred to as RESA I, and the incremental costs of clean energy plan activities recovered with either the CEPR or a combination of the RESA and CEPR riders were described as RESA II.

By the Phase I Decision, the Commission posed specific questions associated with that structure and ordered the Company to include a proposal "with significantly more detail" and with RESA II costs recovered with the CEPR. The proposal is outlined here, recognizing that the Commission also directed a standalone application filing to analyze CEPR and RESA interactions, which the Company intends to file consistent with the Phase I Decision and to build on the proposal outlined here.

The Company's Updated CEPR Proposal

The Company has incorporated the Commission's feedback and has redeveloped its cost recovery proposal, making the structure simpler while remaining consistent with statutory directives and the Phase I Decision. This includes the elimination of the RESA I and II process described above. Below, the Company describes its new process and will supplement this report with a standalone CEPR application filing soon, consistent with the directives in the Phase I Decision.

The Company compared the Preferred Plan to the ERP "business as usual" reference case without the SCC to identify the clean energy plan activities and associated costs recoverable by the CEPR. The Preferred Plan has actions and investments within the RAP that are incremental to the ERP $0/ton portfolio (referred to in this section as the "Reference Case Plan ($0CO2)"), including:

- clean energy resources;
- coal action of converting Pawnee to natural gas by 2026 rather than continuing on coal through 2041;
- coal action of reducing Comanche 3 operations beginning in 2025;

- gas storage;
- transmission;
- community assistance plans; and
- workforce transition plans.

The clean energy resources, Pawnee conversion, and the community assistance and workforce transition plans are clean energy plan activities and are eligible for CEPR recovery (noting that community assistance and workforce transition plan costs are also eligible for separate recovery mechanisms by statute, which can be considered in future JTP filings directed by the Settlement Agreement). The transmission, the fuel costs of reducing Comanche 3 operations, and the gas storage are not clean energy plan activities nor are they CEPR eligible. Transmission costs will be recovered through traditional rate recovery including the Transmission Cost Adjustment and base rates, while fuel and gas storage will be recovered through the Electric Commodity Adjustment.

Clean energy plan activities within the Preferred Plan were identified by a methodology by: (1) categorizing the resources within the Preferred Plan and the Reference Case Plan ($0CO2) portfolio as either energy resources or capacity resources; and (2) subsequently stacking the Preferred Plan energy resources based on their accredited capacity from lowest to highest levelized cost of energy (referred to in this section as the "Energy Resource Stack") and the Preferred Plan capacity resources based on their accredited capacity from lowest to highest levelized cost of capacity (referred to in this section as the "Capacity Resource Stack"). The levelized cost of energy and capacity are calculated from the EnCompass model output and the resources' accredited capacity rather than the bid terms or nominal capacity. Using the modeled cost and accredited capacity reflects the actual expected cost of the resource and also normalizes for the capacity accreditation of firm dispatchable and storage technologies. Energy resources and capacity resources in excess of the ERP "business as usual" need on an accredited capacity basis were identified to be clean energy plan activities. Marginal resources not in excess of the ERP "business as usual" need on an accredited capacity basis were identified as part of the ERP "business as usual" need and therefore were not clean energy plan activities. The marginal resource remaining with the ERP "business as usual" need avoids splitting clean energy plan activities between the ERP "business as usual" need and clean energy plan activities. Further, it alleviates cost pressure on the CEPR, which can in turn lead to a reduced reliance, if any, on the RESA to cover costs associated with the Preferred Plan. This CEPR and RESA interaction will be addressed in more detail in the Company's forthcoming standalone application regarding the CEPR.

Table 43 - Energy Resource Stack

	Bid ID	Type	Project	Structure	COD	Nameplate I	Nameplate II	Accredited	LEC
1	1012	Wind	[redacted]	Own	12/17/2026	302 MW	0 MW	34 MW	[redacted]
2	1026	Wind		Own	7/21/2027	905 MW	0 MW	103 MW	
3	0045	Wind		Own	12/31/2026	375 MW	0 MW	26 MW	
4	0044	Wind		PPA	12/31/2028	375 MW	0 MW	26 MW	
5	1029	Wind		Own	2/27/2026	500 MW	0 MW	57 MW	
6	1015	Wind		Own	3/20/2026	450 MW	0 MW	27 MW	
7	0295	Wind		PPA	12/31/2025	500 MW	0 MW	30 MW	
8	0218	Solar		PPA	3/31/2027	355 MW	0 MW	46 MW	
9	0151	Solar		PPA	12/31/2025	300 MW	0 MW	17 MW	
10	1002	Solar		Own	9/30/2026	335 MW	0 MW	19 MW	
11	1125	Solar		PPA	6/30/2026	115 MW	0 MW	16 MW	
12	0476	Solar + Storage		Own	12/31/2026	199 MW	100 MW	72 MW	
13	1010	Solar + Storage		Own	10/16/2025	325 MW	200 MW	111 MW	
14	1006	Solar + Storage		Own	5/13/2026	250 MW	200 MW	126 MW	
15	0149	Solar + Storage		PPA	5/31/2027	90 MW	72 MW	46 MW	

Figure 27 – Energy Resource Stack

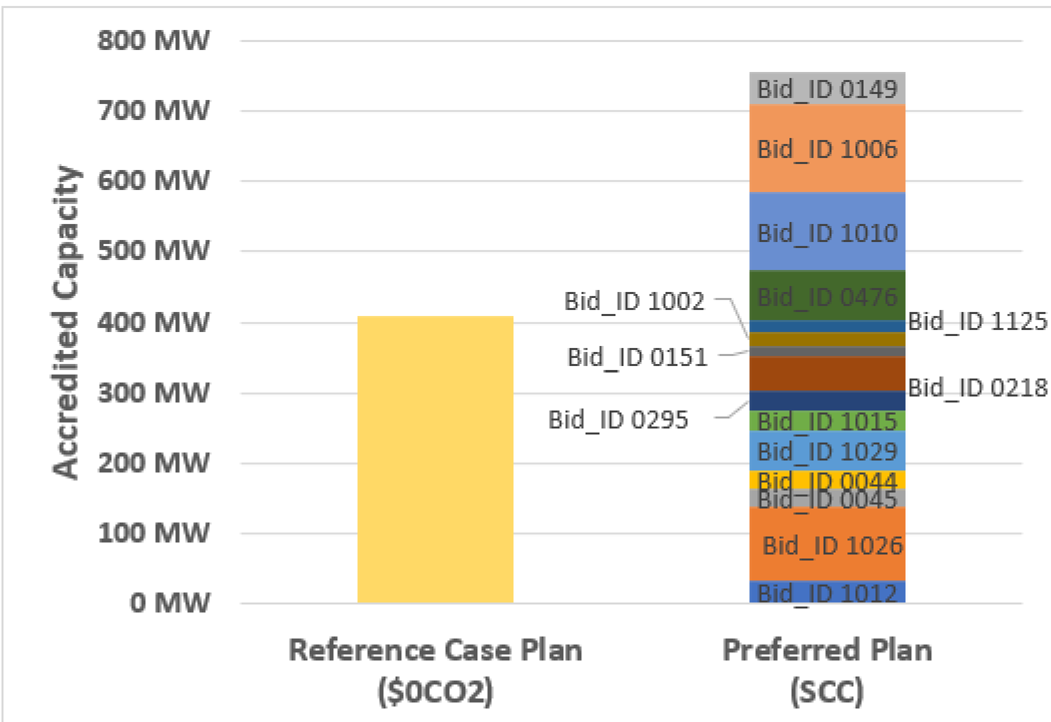
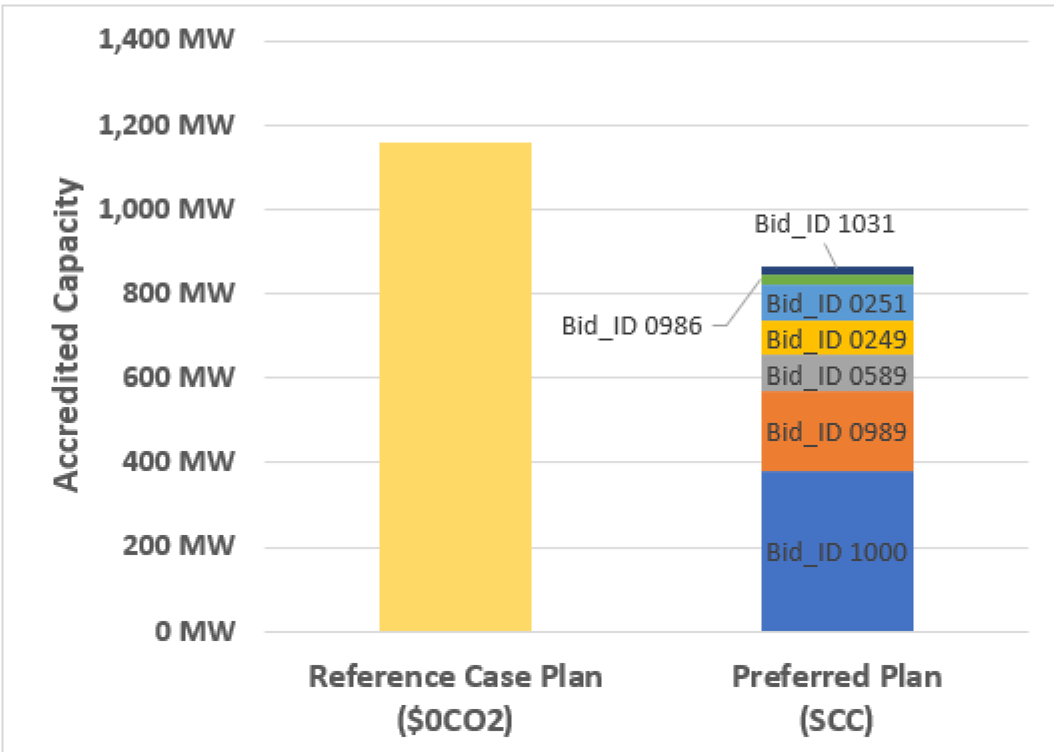


Table 44 - Capacity Resource Stack

	Bid ID	Type	Project	Structure	COD	Nameplate I	Nameplate II	Accredited	LCC
1	1000	Gas	[redacted]	Own	5/31/2027	400 MW	0 MW	379 MW	[redacted]
2	0989	Gas		Own	5/31/2027	200 MW	0 MW	190 MW	
3	0589	Storage		PPA	5/1/2027	200 MW	0 MW	85 MW	
4	0249	Storage		PPA	11/1/2026	199 MW	0 MW	84 MW	
5	0251	Storage		PPA	8/1/2026	199 MW	0 MW	84 MW	
6	0986	Gas		Own	5/31/2027	28 MW	0 MW	23 MW	
7	1031	Biomass		Own	5/31/2028	19 MW	0 MW	19 MW	

Figure 28 – Capacity Resource Stack



Based upon a comparison of the Energy Resource Stack in Figure 27, Bid 1010, 1006, and 0149 are clean energy plan activities in excess of the ERP need while Bid 0476 is a marginal resource and part of the ERP need. The same comparison of the Capacity Resource Stack in Figure 28 demonstrates that there are no clean energy plan activities in excess of the ERP need. In addition to Bid 1010, 1006, and 0149, the Company proposes to recover the Pawnee conversion costs with the CEPR. The Company has approximated this cost as the difference in the capital revenue requirements of Pawnee in the Preferred Plan minus the capital revenue requirements of Pawnee in the Reference Case Plan ($0CO2) from years 2025 through 2030. However, the actual costs to be recovered with the CEPR of the Pawnee conversion will be adjudicated in the standalone CEPR application filing. The yet-to-be-determined costs for community assistance plans and workforce transition plans cannot be appropriately estimated at this time and will be evaluated in future JTP filings. This is consistent with the Phase I Decision, which approved the Company's estimates of these JTP "costs for purposes of Phase II modeling and defers to future proceedings the adjudication and associated cost recovery of the specific workforce transition plans and community assistance plans."

CEPR Implementation

The CEPR is the primary funding mechanism for the incremental costs of the Preferred Plan. Under the proposal delineated above, the Company proposes that the full cost of clean energy plan activities that meet the requirements of CEPR eligible costs will be directly assigned to the CEPR. This will not require more complex incremental cost modeling as has traditionally been performed for the RESA. Other costs will be recovered through traditional recovery mechanisms.

For next steps, the Commission approved in the ERP Phase I Decision that "the CEP Rider impact will be determined in Phase II." The Company is prepared to file an advice letter based on Commission directives in its Phase II Decision. This advice letter would request the CEPR collections begin January 1, 2024 or January 1, 2025, depending on when the Commission issues a decision on the 120-Day Report. The CEPR is authorized by statute and should begin as soon as statute allows to collect revenues that will cover costs later in this decade.

Moreover, the CEPR Tracker will be the account for the CEPR revenue collections and the clean energy plan activity costs, for the under-collected or over-collected balance calculation, for the application of interest on the balance, and for the balance which will be handled consistent with the approved Settlement Agreement (addressed in more detail below) or added to the Company's base rates in the first rate case after implementation of the CEP.

The timing of CEPR implementation affects the projection of whether the balance will be over- or under-collected at the conclusion of the mechanism. First, assuming the recovery of the Bid IDs 1010, 1006, and 0149 and the capital revenue requirements of the Pawnee conversion, the CEPR Tracker forecast would have an over-collected $6.3 million balance by the end of year 2030 assuming a January 1, 2024, start of CEPR collections at 1.4% and a 4% symmetrical interest rate on over- or under-collected balances as shown in Table 45 below. The over-collected balance would be handled consistent with the Settlement Agreement, which provides that "the Company will apply any over-collected balance towards the undepreciated balance of the coal-related portions of Pawnee. Further, to the extent there is any remaining balance after application to Pawnee, the Company will apply it to the remaining net book value and future decommissioning costs of Comanche 3."

Table 45 - CEPR Tracker Forecast ($M) starting January 1, 2024 and 1.4% Collection

	(A)	(B)	(C)	(D) = (A) + (B) + (C)	(E) = (D) * 4%	(F) = (D) + (E)	(G) = (G)' + (F)
Year	CEPR Costs Bid_ID 1010, 1006, 0149	CEPR Costs Pawnee Conversion	CEPR Revenues	Over Collection / (Under Collection)	Interest 4%	Over Collection / (Under Collection) with Interest	CEPR Tracker Balance
2024			$50.1	$50.1	$2.0	$52.1	$52.1
2025	$13.5	($9.4)	$53.8	$57.8	$2.3	$60.1	$112.3
2026	$104.8	($15.0)	$55.4	$145.2	$5.8	$151.0	$263.3
2027	($72.9)	($13.9)	$59.0	($27.9)	($1.1)	($29.0)	$234.3
2028	($131.2)	($13.0)	$60.9	($83.3)	($3.3)	($86.6)	$147.7
2029	($123.1)	($12.4)	$62.0	($73.5)	($2.9)	($76.4)	$71.2
2030	($116.8)	($11.2)	$65.5	($62.4)	($2.5)	($64.9)	$6.3

If the CEPR collection were to begin January 1, 2025 with the same costs and the CEPR collection at 1.5%, the maximum allowed by statute, the CEPR Tracker would have an under-collected balance of $19.3M by the end of year 2030 as shown in Table 46. The under-collected balance would be incorporated into base rates in the first rate case following the implementation of the plan, consistent with the statute.

Table 46 - CEPR Tracker Forecast ($M) starting January 1, 2025 and 1.5% Collection

	(A)	(B)	(C)	(D) = (A) + (B) + (C)	(E) = (D) * 4%	(F) = (D) + (E)	(G) = (G)' + (F)
Year	CEPR Costs Bid_ID 1010, 1006, 0149	CEPR Costs Pawnee Conversion	CEPR Revenues	Over Collection / (Under Collection)	Interest 4%	Over Collection / (Under Collection) with Interest	CEPR Tracker Balance
2024			$0.0	$0.0	$0.0	$0.0	$0.0
2025	$13.5	($9.4)	$57.6	$61.7	$2.5	$64.1	$64.1
2026	$104.8	($15.0)	$59.4	$149.2	$6.0	$155.1	$219.3
2027	($72.9)	($13.9)	$63.2	($23.7)	($0.9)	($24.6)	$194.6
2028	($131.2)	($13.0)	$65.3	($78.9)	($3.2)	($82.1)	$112.6
2029	($123.1)	($12.4)	$66.4	($69.1)	($2.8)	($71.8)	$40.7
2030	($116.8)	($11.2)	$70.2	($57.7)	($2.3)	($60.0)	($19.3)

The CEPR Tracker forecast is subject to further review in the forthcoming standalone CEPR filing to review the cost recovery proposal in more detail. This approach allows for the CEPR to be established for collection purposes with the details of the mechanism itself to be determined in the forthcoming standalone CEPR application filing, which the Company believes is consistent with Phase I directives.

11.3 Renewable Energy Standard Adjustment ("RESA")

The Company will file a RESA forecast through 2030 in the 2022-25 RE Plan proceeding (Proceeding No. 21A-0625EG) within 30 days of issuance of the Commission's final 2021 ERP & CEP Phase II decision. Paragraph 74 of Commission Decision No. C22-0678 in the 2022-25 Renewable Energy Plan proceeding, ordered the Company to file an update to Tables 7-2(a)-(c) of RE Plan Volume II, which project RESA revenues and expenditures through 2030. In the standalone application filing regarding the CEPR, the Company will also address the RESA consistent with Commission directives. The Company does not anticipate requiring RESA funding for implementation of the approved resource portfolio and based on the contents of the Preferred Plan.

11.4 Future Lease Considerations

In its ARRR, the Company requested the Commission reconsider the Phase I Decision's findings directing Public Service to revise its model PPA to allow solar plus storage projects to bid under two separate PPAs (one for solar energy and the other for the storage portion) rather than an energy-only rate for hybrid resources as the Company proposed and, if capacity payments are bid for the storage component, limit the lease term for the storage component to 18 years.

The Company argued an energy-only rate was necessary to avoid the creation of a finance lease classification for the storage component of the hybrid resources, which credit rating agencies would construe as debt. The Company asserted that a PPA will likely be categorized as a finance lease if either: (1) the present value of the lease payments is 90 percent or more of the fair value of the asset; or (2) if the lease term is 75 percent or more of the estimated life of the asset (this is referred to as the "90/75 limitation"). A similar issue arose regarding the PPA terms for standalone storage projects. As with solar plus storage projects, Public Service argued that standalone storage PPAs could be categorized as finance leases, which could negatively impact the Company's credit ratings. Public Service proposed that the model PPA for standalone storage contain terms that prohibit the Company from being subject to the accounting treatment that results from the classification of a PPA as a finance lease.

Public Service's ARRR requested two amendments to the Phase II modeling process if the Commission was unwilling to reverse the relevant model PPA decision points from the Phase I Decision, including: (1) allowing use of the replacement chain tail modeling methodology to "fill the gap" between the two components of a hybrid resource with generic resources to equalize the lives; and (2) allowing the Company to run a credit metrics stress test on any portfolio that includes a solar plus storage project with an energy and capacity payment structure or a standalone storage project that violates the 90/75 limitation. The credit metrics stress test is essentially a repricing sensitivity illustrating use of either a higher equity ratio or an incremental charge to customers to provide additional return on equity ("ROE") to mitigate the imputed debt issue.

In Decision No. C22-0559, the Commission maintained its initial position and continued to find that, while the finance lease issue is a legitimate concern, its approach in which the storage components of hybrid projects can receive capacity payments but are limited to an 18-year term strikes an appropriate balance between addressing the finance lease concern and allowing IPP solar plus storage bids to be more competitive. While the Commission denied Public Service's ARRR requests to place the 90/75 limitation on standalone storage and require solar plus storage projects to bid energy-only rates, the Commission accepted the Company's request to allow for two adjustments to the Phase II modeling process (i.e., the credit metrics stress test and using generic resources to "fill the gap" between the solar component and storage component of hybrid resources).

The Commission indicated that Public Service may include the credit metrics stress test in the 120-Day Report for informational purposes (i.e., this credit metrics stress test will not dictate the resources the model selects) and, if the Company chooses to present the credit metrics stress test, the Company must include a detailed explanation of the assumptions and inputs used in the stress test and why the Company concluded that these assumptions and inputs were appropriate.

Based on the current methodology, Public Service expects that when determining the Company's credit ratings, at least one of the major credit rating agencies will impute debt for all energy storage PPAs that require a capacity payment, regardless of whether the arrangements qualify as finance leases or operating leases. It is currently expected that another major agency will impute debt on PPAs that qualify as finance leases for accounting purposes, but not operating leases.

The Company has not performed its final evaluations of the economic lives of the storage facilities in the various portfolios; with uncertain economic lives for these new technologies, it is difficult to reasonably evaluate at this time whether each of the generally 18-20-year agreements will qualify as a finance lease or an operating lease. The authoritative GAAP guidance for lease accounting, Accounting Standards Codification Topic 842 *Leases*, requires this evaluation be performed/timed on the date the assets are placed in service.

However, given the reasonably certain credit rating impacts for one major agency, and possible impacts for another agency pending final determination of whether certain energy storage PPAs qualify as finance leases, through additional sensitivity analysis below, Public Service has calculated an additional cost, a "credit metrics adder", on the Preferred Plan to rebalance its debt and equity from the perspective of the credit rating agencies.

The following presents this "stress test," or summary of additional charges, in the form of a credit metrics adder sensitivity to the Preferred Plan, that the Company estimates it would need to protect credit ratings. As described above, such a charge would be necessary to mitigate negative credit rating impacts, some reasonably certain as of today, and others pending determination of finance lease treatment following the Commission's Phase I decisions.

The annual credit metrics adder is the approximate amount that Public Service would need to charge customers as ROE on a calculated amount of hypothetical equity, offsetting the debt imputed by the credit ratings agencies, and grossed up for income taxes and levelized for a consistent year-to-year charge.

The inputs to this analysis include the terms of the proposed PPAs as well as estimated income tax rates, interest rates, ROE, and debt to equity ratios generally approximating current rates and ratios (see Highly Confidential Appendix M for the actual inputs and calculations). This sensitivity is being run on the Preferred Plan, but other presented portfolios could trigger similar impacts to the extent they include projects that trigger finance lease or operating lease treatment. Table 47 below summarizes the Preferred Plan storage projects and associated annual credit metrics adder.

Table 47 - Preferred Plan Annual Credit Metrics Adder

Bid ID	Project Name	PPA Term (Years)	Storage Capacity (MW)	Annual Credit Metrics Adder ($ millions)
0149	[redacted]	18	72	$4
0589	[redacted]	18	200	$10
0249	[redacted]	20	199	$11
0251	[redacted]	20	199	$11

This adder is presented as a sensitivity here in this proceeding to quantify what Public Service believes is necessary to mitigate these impacts and can be the subject of further discussions in relevant future cases.

12.0 Next Steps, Related Future Filings and Conclusion

This Section discusses next steps and related filings that will occur following the filing of this Report within the context of this proceeding as well as follow-on proceedings and related future filing requirements before the Commission pursuant to the Updated Settlement Agreement and other Commission directives. These next steps and related filings are summarized below. Finally, this Section provides a brief conclusion and request for approval of the Preferred Plan.

12.1 Next Steps

- **CDPHE Verification**

The Company will coordinate with the Colorado Department of Public Health and Environment ("CDPHE") to provide necessary emissions reduction information to facilitate the CDPHE's emissions verification process. The CDPHE verification of the emission reductions of modeled portfolios presented in this 120-Day Report will be submitted to the Commission 30 days after filing this 120-Day Report. After the Commission issues its Phase II Decision, CDPHE will perform a "safe harbor" determination within ten days of the Phase II Decision for purposes of House Bill 19-1261 (and more specifically, § 25-7-105(1)(e)(VIII)(C), C.R.S.). There will be a subsequent "safe harbor" determination if the Phase II Decision is modified by any ARRR in any manner that affects the projected 2030 emissions associated with the Company's plan.[98] Highly Confidential and public versions of the verification workbooks are provided as Appendix X1 through X37.

- **IE Report, Comment Period, and Commission Decision**

By Decision Nos. C23-0246-I, C23-0522-I, and C23-0594-I, the Commission granted the Company's requests for extension of time to file this 120-Day Report and also granted applicable partial waivers of Rules 3613(e)-(h), which outline subsequent filing requirements that are keyed off the filing date of the 120-Day Report. At the Commissioners' weekly meeting on September 13, 2023 (written decision is pending), the Commission further modified the Phase II deadlines and set October 20, 2023 for the IE to file its report; November 8, 2023 for Parties to file comments; and November 20, 2023 for Public Service to file response comments. The Commission stated their preference to issue its Phase II Decision by the end of the year (i.e., preferably by December 18, 2023).

[98] Decision No. C22-0459, at ¶¶461-463.

- **Contract Negotiations**

Associated with issuance of the final Phase II Decision, Public Service will pursue contract negotiations/next steps with bidders in the approved plan for both IPP-owned and utility-owned generation resources consistent with Rule 3613(h) and any Commission directives of the final Phase II Decision. Due to the extensions granted by the Commission to file this Report, the inherent complexity of the details and supporting documentation of each bid, and the continuously fluctuating market and supply chain environments, on September 11, 2023 (i.e., the previous date for filing the 120-Day Report before the Commission approved the extension to file on September 18, 2023) Public Service notified bidders included in the Preferred Plan and back-up bidders, on a confidential basis, of their selection.[99] This notification allows selected bidders to begin to take steps to move forward and develop projects, understanding that the Phase II Decision will be the ultimate approval of projects in the approved resource plan. In addition, this notification allows Public Service to ensure (1) the selected bidder and their proposed project remains viable since bidder originally submitted the bid earlier this year, and (2) the proposed details and/or commitments of each proposal are accurate as bidder intended. Following assurance from each bidder of the viability and intent of their bid, on or around October 1, 2023, Public Service will begin the process of collecting the second bid fees identified in the RFP. Following the collection of each bidder's second bid fee, in order to facilitate negotiations in an efficient manner, Public Service will begin initiating negotiations of each bid prior to and in anticipation of a supportive final Phase II Decision later this year or early next year. If for any reason, any Commission directives or final Phase II Decision later causes, discourages and/or prevents a negotiation from continuing, then the affected second bid fee shall be refunded as applicable.

- **Transmission Studies**

As stated in Paragraph 326 of the Phase I Decision and discussed further in Appendix Q, once final resources are approved through the Commission's Phase II decision, the Company will then perform more detailed planning studies and begin generator interconnection studies. Following these studies, Public Service will file follow-on transmission CPCN applications, if required, with CPCN-quality cost estimates for these additional transmission investments needed to interconnect and deliver the approved generation resources.

[99] By Decision No. C23-0594-I at ¶18, the Commission affirmed the Company has never been prohibited from conferring with potential preferred bidders in finalization of its 120-Day Report and no Commission finding is required regarding conferral.

- **Performance Incentive Mechanism ("PIM") Stakeholder Coordination and Filing**

Pursuant to Paragraphs 50-51 of the Settlement Agreement and the Phase I Decision, the Company will conduct a stakeholder process to develop PIM(s) as required by the Commission, regarding: (1) emissions reductions (volume and timeliness) associated with the Preferred Portfolio, and (2) Comanche Unit 3's O&M expenses, capital costs, and availability factor.[100] In general, the PIM(s) should adhere to the Commission's guidelines outlined in Paragraph 390 of the Phase I Decision and other directives set forth in the Phase I Decision.[101]

The stakeholder process will be initiated by the Company no later than 15 days after the filing of this 120-Day Report at which the parties will attempt to reach a consensus proposal to bring to the Commission for review. The Company will file a PIM proposal, with supporting testimony, 60 days after filing the 120-Day Report. A 30-day comment period will commence upon the PIM proposal filing for any interested ERP parties (Proceeding No. 21A-0141E) that would like to comment on the PIM proposal. Moreover, pursuant to Paragraph 86 of the Phase I Decision, the Company will include a narrative describing Comanche Unit 3 planned overhauls.

- **Stakeholder Group Regarding Curtailment Processes**

As set forth in Paragraph 58 of the Settlement Agreement, the Company, Interwest members, CIEA members, COSSA members, and other interested Settling Parties will convene a stakeholder group to discuss curtailment expectations and utilization on the Public Service system and approaches to work through curtailment processes as the Company continues to transition to increasing levels of variable generation, as well as diversity benefits and ways to use the real time attributes of inverter-based resources for ancillary services to support grid reliability. The Company anticipates convening the first stakeholder group on or around September 22, 2023.

- **Pawnee Conversion CPCN (Proceeding No. 22A-0563E)**

On December 20, 2022, the Company filed an application and supporting Direct Testimony for approval of a CPCN for the conversion of the Pawnee Generating Station from coal operations to natural gas operations as required by the Phase I Decision.[102] As discussed in detail in Proceeding No. 22A-0563E, the Company will principally

[100] Decision No. C22-0559, at ¶10 removed the directive for the parties to craft a DR PIM in this Proceeding's stakeholder process.
[101] Decision No. C22-0459, at ¶¶389-395.
[102] Decision No. C22-0459, at ¶ 63 approved paragraph 31 of the Settlement Agreement which states, in part: "The Company will file a CPCN within 90 days of a final Phase I decision in this proceeding." Commission Decision No. C22-0559 (i.e., the final Phase I decision) was mailed September 21, 2022.

conduct the conversion of Pawnee in or around the Fall of 2025 in conjunction with an anticipated planned outage of the unit with estimated completion before December 2025. The timing of this conversion was carefully considered with thought given to the potential impact on resource adequacy and system reliability given the important role the unit plays. The Company does request Commission flexibility to advance this conversion in time if it believes it can reasonably do so while maintaining system reliability, resource adequacy, and the cost reviewed by the Commission through this proceeding. The Company is currently forecasting a cost of approximately $83 million in capital costs, plus an Allowance for Funds Used During Construction ("AFUDC") of approximately $4 million to conduct the conversion as detailed in the Company's Supplemental Direct Testimony filed on May 15, 2023. The Company is not seeking an advance presumption of prudence for the conversion costs but asks the Commission to confirm that Public Service will recover all costs that it reasonably and prudently incurs for the conversion, consistent with the CPCN approval.

Given the Commission's approval to extend the filing date of this 120-Day Report to September 18, 2023, on September 14, 2023, the Company filed an unopposed motion to approve a revised procedural schedule in Proceeding No. 22A-0563E so that the parties[103] have adequate time to review and address the 120-Day Report in their case presentations. The unopposed motion pending with the Commission proposes September 27, 2023 as the deadline for parties in the proceeding to file Answer Testimony, and October 25, 2023 as the deadline to file Rebuttal and Cross-Answer Testimony. The discovery procedures remain as previously agreed to by the parties, and the remaining procedural schedule is proposed to remain as previously approved in Decision No. R23-0542-I to maintain the hearing schedule of November 7 and 9, 2023.

12.2 Related Future Filings

- **CEPR Methodology Filing**

The Company will file an Application as directed by Paragraph 140 of the Phase I Decision presenting its methodology for defining and assigning costs related to additional CEP activities as between the CEP rider ("CEPR") and the RESA. As explained by the Commission, this additional proceeding is intended to allow for more robust and concrete vetting of Public Service's accounting. As discussed above in Section 11, the Company anticipates the CEPR will be set at a level below the statutory cap and does not foresee a need to utilize RESA funding.

[103] Parties to Proceeding No. 22A-0563E include Trial Staff of the Commission ("Staff"); the Colorado Office of the Utility Consumer Advocate ("UCA"); Sierra Club and Natural Resources Defense Council ("NRDC") (collectively, the "Conservation Coalition"); and Climax Molybdenum Company.

- **Certificate of Public Convenience and Necessity ("CPCN") Applications**

The Company will prepare and file all necessary CPCN applications, including for: (1) "limited scope" CPCN applications that the Commission may require for the retirement of existing generation units; (2) utility-owned generation projects; and (3) transmission facilities that are subject to CPCN requirements. Cost recovery issues associated with these generation and transmission facilities can be adjudicated before the Commission through these CPCN proceedings.

- **Just Transition Plans**

As outlined in Paragraph 26 of the Settlement Agreement, the Company will file post-Phase II Decision updated Just Transition Plans ("JTP") for each affected area where the Company is the operator of the affected coal plant and the plant is subject to a comprehensive or partial accelerated retirement under the CEP (i.e., Hayden, Pawnee, and Comanche Unit 3). The JTP filings will include Workforce Transition Plan costs, community assistance costs, and any offsets to community assistance costs due to investments in the relevant community as approved by the final Phase II Decision. The JTP filings will also include a proposal for a cost recovery mechanism (if not already addressed in a rate case) for any JTP costs. These plans could continue to be iterated through future ERP cycles as retirement dates get closer in time if their retirement is outside of this RAP (i.e., Comanche Unit 3). The Company will file an updated JTP for Hayden within 120 days of the final Phase II Decision consistent with Paragraph 28 of the Settlement Agreement. The Company will file an updated JTP for Comanche Unit 3 as part of the Pueblo Just Transition Plan solicitation filing no later than June 1, 2024 consistent with Paragraph 45 of the Settlement Agreement. While neither the Settlement Agreement nor Phase I Decision specify a timeframe for filing an updated Pawnee JTP, the Company anticipates filing an updated Pawnee JTP sometime in 2025.

- **Pueblo Just Transition Plan Solicitation**

As noted above and as outlined in Paragraphs 43-48 of the Settlement Agreement, the Company will file the Pueblo Just Transition Plan ("Pueblo JTP") by June 1, 2024. All 2029 and 2030 resource needs identified will be filled through the Pueblo JTP, which will utilize a Resource Acquisition Period through end of year 2031. The Pueblo JTP will also utilize a standalone all-source competitive solicitation for the replacement of the energy and capacity associated with Comanche 3 in an effort to ensure the Pueblo community and benefits to the community are the focus of the replacement portfolio, simultaneously seeking just transition benefits and the procurement of innovative technologies to help the Company progress towards a carbon-free future. With the exception of the updated assumptions and studies detailed in Paragraph 43 of the Settlement Agreement, the all-source competitive solicitation will utilize the modeling inputs and assumptions approved in the most recent Phase I ERP unless good cause is shown to modify the modeling inputs and assumptions. To the extent that any procedures or aspects of the Pueblo JTP filing are not addressed by the Settlement

Agreement, the application proceeding will be treated as an Interim ERP under Rule 3603(a) and will otherwise comply with applicable ERP Rules for the first and second phases of the process. The Pueblo JTP will also utilize the ownership and emission reduction target detailed in Paragraphs 44 and 45 of the Settlement Agreement.

- **Next ERP Filing**

Pursuant to Paragraph 65 of the Settlement Agreement, the Company will file its next ERP under Rule 3601 no later than October 31, 2026.[104] The Company may present a request for variance to this deadline if future circumstances warrant a change and Settling Parties in this Proceeding may advocate for a different filing deadline based on circumstances in the future.

- **Transmission Interconnection Expansion Study**

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

- **Retiring Coal Plant Cost Recovery & Securitization Analysis**

In its Phase I Decision, the Commission adopted the retirement and conversion dates for all coal generating units as well as provisions concerning cost recovery for the early retirement of Comanche 3 without modification. However, the Commission concluded that the record on cost recovery associated with the early retirements of units Craig 2, Hayden 1, Hayden 2, and the retired coal portion of Pawnee was inadequate and ordered Public Service address an appropriate cost recovery approach for these assets through a separate application. Specifically, Paragraph 65 of the Commission's Phase I Decision ordered Public Service to present the recovery of unamortized balances and decommissioning costs at each of the coal plants using at least four different methods: regulatory asset approach, accelerated depreciation, financing at the long-term cost of debt, and securitization. The Commission's Phase I Decision also ordered the Company to address specific questions around securitization. Accordingly, on November 16, 2022, the Company filed an Application in Proceeding No. 22A-0515E

[104] Decision No. C22-0459, at ¶439.

regarding its cost recovery proposal associated with the early retirements of coal generation assets.

By Decision No. C23-0362 (issued May 30, 2023), the Commission approved an Unopposed Comprehensive Settlement Agreement that establishes how the Company will recover the remaining net book values ("NBVs") and decommissioning costs associated with the early retirements of units Craig 2, Hayden 1, Hayden 2, and the retiring coal portion of Pawnee as it converts to natural gas generation (collectively, "Coal Assets"). In summary, cost recovery of the NBVs and prudently incurred decommissioning costs associated with the early retirement of the Coal Assets will be through the creation of a separate regulatory asset for each of the Coal Assets, with an amortization period of eight years, with the exception of Pawnee, for which the amortization period will be set at 12 years ("Coal Regulatory Assets").

Financing Order Application

Through the Settlement Agreement approved by Decision No. C23-0362, the Company agreed to present a bundled securitization, including the Coal Regulatory Assets together with amounts related to Comanche 3, as a part of the financing order application pursuant to paragraph 35 of the Settlement Agreement in Proceeding No. 21A-0141E, to be filed no later than April 1, 2030. The bundled securitization will be compared to regulatory asset recovery for the Coal Regulatory Assets, with the above discussed amortization periods and a return at the long-term cost of debt after 2030.

12.3 Conclusion

Under the Preferred Plan, Public Service will exit coal by the end of this decade, build an unprecedented amount of wind and solar energy, reduce carbon emissions by more than 80% from 2005 levels, and maintain a reliable grid, all with an average annual rate impact of approximately 2.25%, in line with the rate of inflation.

By bringing over 6,500 MW of clean energy resources online by 2028, the Preferred Plan maximizes the opportunities presented by both the IRA and the CPP. By leveraging the IRA, it brings billions of dollars in federal support to Colorado and delivers these benefits to the doorsteps of customers in the form of new clean energy options. More specifically, the Preferred Plan brings $10 billion in IRA benefits to customers, $14 billion in energy investment to Colorado, and $2.5 billion in tax benefits alone to local communities in the coming decades.

The Preferred Plan satisfies the public interest criteria for a Clean Energy Plan by exceeding the 2030 statutory clean energy target, maintaining a reliable and resilient system, and achieving these two objectives at reasonable cost. The Commission should make these findings and approve the Preferred Plan as the most transformational step yet in Colorado's energy transition.

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