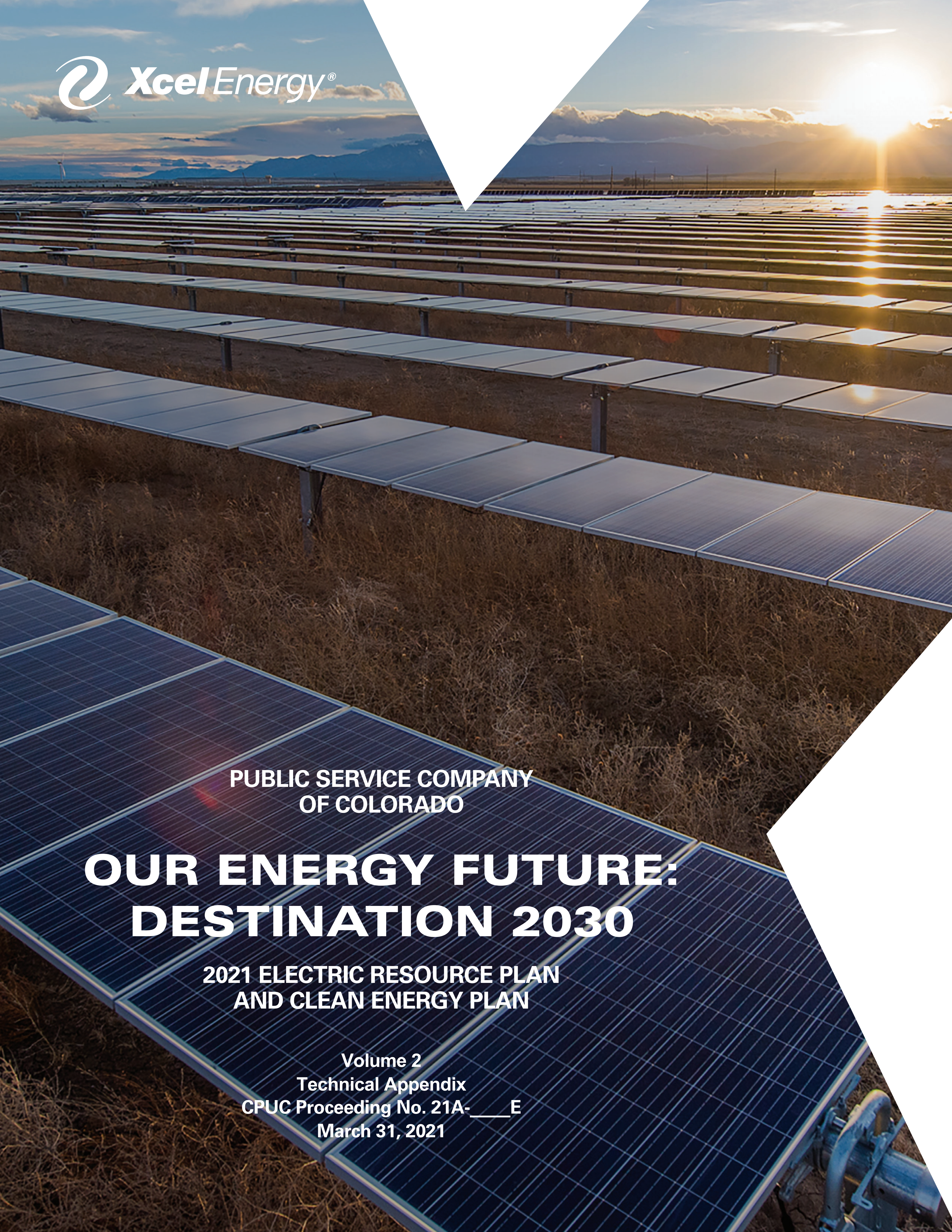

Xcel Energy®

PUBLIC SERVICE COMPANY
OF COLORADO

OUR ENERGY FUTURE: DESTINATION 2030

2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN

Volume 2
Technical Appendix
CPUC Proceeding No. 21A-____E
March 31, 2021

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2.0 CONTENTS OF THE ELECTRIC RESOURCE PLAN

Rule 3604 of the Colorado Public Utilities Commission's ("Commission") Electric Resource Planning Rules, 4 CCR 723-3-3600 *et seq.* ("ERP Rules") sets forth the required contents of the Electric Resource Plan ("ERP").

On February 27, 2019, the Commission issued a Notice of Proposed Rulemaking ("NOPR") in Proceeding No. 19R-0096E to amend several areas of the Commission's Rules Regulating Electric Utilities, including amendments to the ERP Rules. The Company and many other stakeholders filed numerous rounds of comments and participated in several hearings over the course of the rulemaking proceeding.

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.[1] However, during their deliberations, the Commission notified the Company of three issue areas in which interested stakeholders had general agreement, that they expect will be addressed in the Company's 2021 Electric Resource Plan and Clean Energy Plan ("2021 ERP & CEP") filing, including:

1. **Energy and Demand Forecasting:** Specifically, the Commission noted the several interested stakeholders filed blueline revisions to Rule 3606(b) on December 20, 2019 in response to Decision No. C20-0207-I. The Company then filed bluelines in response on January 16, 2020. A consensus on Rule 3606(b)(I)-(II) was achieved. The Company has complied with the spirit of Proposed Rule 3606(b)(I)-(II) by developing base, low, and high (Roadmap) forecast scenarios as discussed in Section 2.2 of this Volume 2;

2. **Joint Transmission Proposal:** On October 30, 2020, the Company filed Updated Joint Transmission Proposal and Joint Final Comments in response to Decision No. C20-0661-I in Proceeding No. 19R-0096E (the "Joint Transmission Proposal"). The Joint Transmission Proposal aimed to better align transmission planning and resource planning by allowing for bidding into bid-eligible planned transmission projects in the Phase II competitive solicitation without burdening developers with costs from the transmission project.[2]

   During their deliberations, the Commission directed the Company to address in its 2021 ERP & CEP, to the extent necessary, how the Company has incorporated the Joint Transmission Proposal into its 2021 ERP & CEP filing recognizing that since the development of this proposal the Company has filed Colorado's Power

[1] As of the writing of this document, the Commission's written Decision is pending.

[2] Proceeding No. 19R-0096E, Updated Joint Transmission Proposal and Joint Final Comments to Decision No. C20-0661-I (filed Oct. 30, 2020), at 9-10.

Pathway 345 kV Transmission Project in Proceeding No. 21A-0096E. The Joint Transmission Proposal is discussed in Section 2.8 of this Volume 2.

3. **Best Value Employment Metrics:** During their deliberations, the Commission noted that the Company worked closely with Rocky Mountain Environmental Labor Coalition and Colorado Building and Construction Trades Council, AFL-CIO (jointly, "RMELC/CBCTC") to propose rule revisions (reflected in Proposed Rule 3613) that could improve the existing best value employment metrics ("BVEM") requirements given past disputes over the proper application of BVEM related rules. The Commission indicated that their decision closing Proceeding No. 19R-0096E will articulate that bidders will be required to provide the more detailed BVEM information reflected in Proposed Rule 3613 and that bidders should know that this information is now required to be obtained as a result of Senate Bill 19-236 ("SB 19-236") (§ 40-2-129, C.R.S.). The Commission further stated that it expects the Company to include a request for the more detailed BVEM requirements as outlined in Proposed Rule 3613 in its Request for Proposal ("RFP") documents. BVEM is discussed further in Section 2.16 of this Volume 2.

In addition to the three issues discussed above, the Company has also addressed several other Proposed Draft Rules that were the product of significant stakeholder engagement, including:

- **Proposed Draft Rule 3607(c):** Benchmarking for the purpose of identifying existing resources that potentially are not performing cost-effectively as compared to other resources available in the market (Section 2.5);

- **Proposed Draft Rule 3604(l):** Assessment of potential cost-effective early retirements of utility-owned resources (Section 2.6); and

- **Proposed Draft Rule 3607(d):** Ancillary services assessment of existing resources (Section 2.7).

Table 2.0-1 below, which reflects the current rules as of the date of the Company's filing, provides a matrix of the applicable rule requirements and indicates where the information can be found throughout Volume 2, and/or Volume 3 of the Company's 2021 ERP & CEP. Table 2.0-2 further below reflects the select Proposed Draft Rules the Company has also addressed in its 2021 ERP & CEP filing.

Table 2.0-1 ERP Rules Compliance Matrix

CPUC Rule	Required Information	Where
Rule 3604	**Contents of the Resource Plan**	
	The utility shall file a plan with the Commission that contains the information specified below. When required by the Commission, the utility shall provide work-papers to support the information contained in the plan. The plan shall include the following:	
Rule 3604	**Resource Acquisition Period and Planning Period**	
3604(a)	A statement of the utility-specified resource acquisition period and planning period. The utility shall consistently use the specified resource acquisition and planning periods throughout the entire resource plan and resource acquisition process. The utility shall include a detailed explanation as to why the specific period lengths were chosen in light of the assessment of the needs of the utility system.	Volume 2, Section 2.1
Rule 3604(b) & 3606	**Electric Demand and Energy Forecast**	
3604(b)	An annual electric demand and energy forecast developed pursuant to rule 3606.	Volume 2, Section 2.2
3606(a)	Forecast requirements. The utility shall prepare the following energy and demand forecasts for each year within the planning period:	
3606(a)(I)	Annual sales of energy and coincident summer and winter peak demand in total and disaggregated among Commission jurisdictional sales, FERC jurisdictional sales, and sales subject to the jurisdiction of other states.	
3606(a)(II)	Annual sales of energy and coincident summer and winter peak demand on a system wide basis for each major customer class.	
3606(a)(III)	Annual energy and capacity sales to other utilities; and capacity sales to other utilities at the time of coincident summer and winter peak demand.	
3606(a)(IV)	Annual intra-utility energy and capacity use at the time of coincident summer and winter peak demand.	
3606(a)(V)	Annual system losses and the allocation of such losses to the transmission and distribution components of the system. Coincident summer and winter peak system losses and the allocation of such losses to the transmission and distribution components of the systems.	
3606(a)(VI)	Typical day load patterns on a system-wide basis for each major customer class. This information shall be provided for peak-day, average-day, and representative off-peak days for each calendar month.	Volume 2, Section 2.3

CPUC Rule	Required Information	Where
3606(b)	Range of forecasts. The utility shall develop and justify a range of forecasts of coincident summer and winter peak demand and energy sales that its system may reasonably be required to serve during the planning period. The range shall include base case, high, and low forecast scenarios of coincident summer and winter peak demand and energy sales, based on alternative assumptions about the determinants of coincident summer and winter peak demand and energy of coincident summer and winter peak demand and energy sales during the planning period.	Volume 2, Section 2.2
3606(c)	Required detail.	
3606(c)(I)	In preparing forecasts, the utility shall develop forecasts of energy sales and coincident summer and winter peak demand for each major customer class. The utility shall use end-use, econometric or other supportable methodology as the basis for these forecasts. If the utility determines not to use end-use analysis, it shall explain the reason for its determination as well as the rationale for its chosen alternative methodology.	
3606(c)(II)	The utility shall maintain, as confidential, information reflecting historical and forecasted demand and energy use for individual customers in those cases when an individual customer is responsible for the majority of the demand and energy used by a particular rate class. However, when necessary in the resource plan proceedings, such information may be disclosed to parties who intervene in accordance with the terms of non-disclosure agreements approved by the Commission and executed by the parties seeking disclosure.	
3606(d)	Historical data. The utility shall compare the annual forecast of coincident summer and winter peak demand and energy sales made by the utility to the actual coincident peak demand and energy sales experienced by the utility for the five years preceding the year in which the plan under consideration is filed. In addition, the utility shall compare the annual forecasts in its most recently filed resource plan to the annual forecasts in the current resource plan.	
3606(e)	Description and justification. The utility shall fully explain, justify, and document the data, assumptions, methodologies, models, determinants, and any other inputs upon which it relied to develop its coincident peak demand and energy sales forecasts pursuant to this rule, as well as the forecasts themselves.	Volume 2, Section 2.2
3606(f)	Format and graphical presentation of data. The utility shall include graphical presentation of the data to make the data more understandable to the public and shall make the data available to requesting parties in such electronic formats as the Commission shall reasonably require.	

CPUC Rule	Required Information	Where
Rule 3604(c) & 3607	**Evaluation of Existing Resources**	
3604(c)	An evaluation of existing resources developed pursuant to rule 3607.	
3607(a)	Existing generation resource assessment. The utility shall describe its existing resources, all utility-owned generating facilities for which the utility has obtained a Certificate of Public Convenience and Necessity (CPCN) from the Commission pursuant to § 40-5-101, C.R.S., at the time the plan is filed, and existing or future purchases from other utilities or non-utilities pursuant to agreements effective at the time the plan is filed. The description shall include, when applicable, the following:	Volume 2, Section 2.4
3607(a)(I)	Name(s) and location(s) of utility-owned generation facilities and energy storage systems.	
3607(a)(II)	Rated capacity and net dependable capacity of utility-owned generation facilities.	
3607(a)(III)	Fuel type, heat rates, annual capacity factors and availability factors projected for utility- owned generation facilities availability factors for utility-owned energy storage systems over the resource acquisition period.	
3607(a)(IV)	Estimated in-service dates for utility-owned generation facilities for which a CPCN has been granted but which are not in service at the time the plan under consideration is filed.	
3607(a)(V)	Estimated remaining useful lives of existing generation facilities and energy storage systems without significant new investment or maintenance expense.	
3607(a)(VI)	The amount of capacity and energy from generation facilities, energy storage systems, and demand-side resources purchased from utilities and non-utilities, the duration of such purchase contracts and a description of any contract provisions that allow for modification of the amount of capacity and energy from generation facilities or energy storage systems purchased pursuant to such contracts.	

CPUC Rule	Required Information	Where
3607(a)(VII)	The amount of capacity and energy provided from generation facilities and energy storage systems pursuant to wheeling or coordination agreements, the duration of such wheeling or coordination agreements, and a description of any contract provisions that allow for modification of the amount of capacity and energy from generation facilities or energy storage systems provided pursuant to such wheeling or coordination agreements.	Volume 2, Section 2.4
3607(a)(VIII)	The performance characteristics of utility-owned energy storage systems including but not limited to discharge rates and durations, charging rates, response time; and cycling losses and limitations.	
3607(a)(IX)	The physical and performance characteristics of energy storage systems purchased from utilities and non-utilities including but not limited to: storage technology; discharge rates and durations; charging rates; response time; and cycling losses and limitations.	
3607(a)(X)	The projected emissions, in terms of pounds per MWH and short-tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for the resources identified under this paragraph 3607(a).	
3607(a)(XII)	The expected demand-side resources during the resource planning period from existing measures installed through utility-administered programs; and, from measures expected to be installed in the future through utility-administered programs in accordance with a Commission-approved plan.	
3607(b)	Utilities required to comply with these rules shall coordinate their electric resource plan filings such that the amount of electricity purchases and sales between utilities during the planning period is reflected uniformly in their respective plans. Disputes regarding the amount, timing, price, or other terms and conditions of such purchases and sales shall be fully explained in each utility's plan. If a utility files an interim plan as specified in rule 3603, the utility is not required to coordinate that filing with other utilities.	
Rule 3604(d) & 3608	**Transmission Resources**	
3608(a)	The utility shall report its existing transmission capabilities, and future needs during the planning period, for facilities of 115 kilovolts and above, including associated substations and terminal facilities. The utility shall generally identify the location and extent of transfer capability limitations on its transmission network that may affect the future siting of resources.	Volume 2, Section 2.8
3608(b)	With respect to future needs, the utility shall submit a description of all transmission lines and facilities appearing in its most recent report filed with the Commission pursuant to § 40-2-126, C.R.S., that, as identified in that report, could reasonably be placed into service during the resource acquisition period.	

CPUC Rule	Required Information	Where
3608(c)	For each transmission line or facility identified in paragraph (b), the utility shall include the following information detailing assumptions to be used for resource planning and bid evaluation purposes:	
3608(c)(I)	Length and location.	
3608(c)(II)	Estimated in-service date.	
3608(c)(III)	Injection capacity.	
3608(c)(IV)	Estimated costs.	
3608(c)(V)	Terminal points.	
3608(c)(VI)	Voltage and megawatt rating.	
3608(d)	In order to equitably compare possible resource alternatives, the utility shall consider the transmission costs required by, or imposed on the system by, and the transmission benefits provided by a particular resource as part of the bid evaluation criteria.	
3608(e)	The resource plan shall describe and shall estimate the cost of all new transmission facilities associated with any specific resources proposed for acquisition other than through a competitive acquisition process.	N/A
Rule 3604(e) & 3609	**Planning Reserve Margin & Contingency Plans**	
3604(e)	An assessment of planning reserve margins and contingency plans for the acquisition of additional resources developed pursuant to rule 3609.	Volume 2, Section 2.9
3609(a)	The utility shall provide a description of, and justification for, the means by which it assesses the desired level of reliability on its system throughout the planning period (e.g., probabilistic or deterministic reliability indices).	
3609(b)	The utility shall develop and justify planning reserve margins for the resource acquisition period for the base case, high, and low forecast scenarios established under rule 3606, to include risks associated with: (1) the development of generation, (2) losses of generation capacity, (3) purchase of power, (4) losses of transmission capability, (5) risks due to known or reasonably expected changes in environmental regulatory requirements, and (6) other risks. The utility shall develop planning reserve margins for its system over the planning period beyond the resource acquisition period for the base case forecast scenario. The utility shall also quantify the recommended or required reliability performance criteria for reserve groups and power pools to which the utility is a party.	
3609(c)	Since actual circumstances may differ from the most likely estimate of future resource needs, the utility shall develop contingency plans for the resource acquisition period. As a part of its plan, the utility shall provide, under seal, a description of its proposed contingency plans for the acquisition of (1) additional resources if actual circumstances deviate from the most likely estimate of future resource needs developed pursuant to rule 3610, or (2) replacement resources in the event that resources are not developed in accordance with a Commission-approved plan under rule 3617. The utility will identify the estimated costs it will incur in developing the contingency plan for addressing the acquisition of these resources (*e.g.,* purchasing equipment options, establishing sites, engineering). The Commission will consider approval of contingency plans only after the utility	

CPUC Rule	Required Information	Where
	receives bids, as described in subparagraph 3618(b)(II). The provisions of paragraph 3617(d) shall not apply to the contingency plans unless explicitly ordered by the Commission.	
3604(f) & 3610	**Assessment of Need for Additional Resources**	
3604(f)	An assessment of the need for additional resources developed pursuant to rule 3610.	Volume 2, Section 2.11 & 2.12
3610(a)	By comparing the electric energy and demand forecasts developed pursuant to rule 3606 with the existing level of resources developed pursuant to rule 3607, and planning reserve margins developed pursuant to rule 3609, the utility shall assess the need to acquire additional resources during the resource acquisition period.	
3610(b)	In assessing its need to acquire additional resources, the utility shall also: (I) determine the additional eligible energy resources, if any, the utility will need to acquire to comply with the Commission's RES rules; (II) take into account the demand-side resources it must acquire to meet the energy savings and peak demand reduction goals established under §40-3.2-104 C.R.S. To that end, the Commission shall permit the utility to implement cost-effective demand-side resources to reduce the need for additional resources that would otherwise be met through a competitive acquisition process pursuant to rule 3611; (III) consider the benefits energy storage systems may provide to increase integration of intermittent resources, improve reliability, reduce the need for increased generation facilities to meet periods of peak demand; and avoid, reduce, or defer investments.	
3610(b)(I)	Determine the additional renewable energy resources (*e.g.,* retail distributed generation (DG), wholesale DG, non-DG) resources, if any, the utility will need to acquire to comply with the Commission's Renewable Energy Standard Rules.	
3610(b)(II)	Take into account the demand-side resources it must acquire to meet the energy savings and peak demand reduction goals established under § 40-3.2-104, C.R.S. To that end, the Commission shall permit the utility to implement cost-effective demand-side resources to reduce the need for additional resources that would otherwise be met through a competitive acquisition process pursuant to rule 3611.	
3610(b)(III)	Consider the benefits energy storage systems may provide to increase integration of intermittent resources, improve reliability; reduce the need for increased generation facilities to meet periods of peak demand; and avoid, reduce, or defer investments.	Volume 2, Section 2.10

CPUC Rule	Required Information	Where
3610(c)	The Commission may give consideration of the likelihood of new environmental regulations and the risk of higher future costs associated with the emission of greenhouse gases such as carbon dioxide when it considers utility proposals to acquire additional resources during the resource acquisition period.	
3604(g) & 3611	**Resource Acquisition Plan**	
3604(g)	The utility's plan for acquiring these resources pursuant to rule 3611, including a description of the projected emissions, in terms of pounds per MWh and short-tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its resource plan.	Volume 2, Section 2.4 & Section 2.16
3611(a)	It is the Commission's policy that a competitive acquisition process will normally be used to acquire new utility resources. The competitive bid process should afford all resources an opportunity to bid, and all new utility resources will be compared in order to determine a cost- effective resource plan (*i.e.,* an all-source solicitation).	Volume 2, Section 2.16
3611(b)	Notwithstanding the Commission's preference for all-source bidding for the acquisition of all new utility resources under these rules, the utility may propose in its filing under rule 3603, an alternative plan for acquiring the resources to meet the need identified in rule 3610. The utility shall specify the portion of the resource need that it intends to meet through an all-source competitive acquisition process and the portion that it intends to meet through an alternative method of resource acquisition.	
3611(c)	If the utility proposes that a portion of the resource need be met through an alternative method of resource acquisition, the utility shall identify the specific resource(s) that it wishes to acquire and the reason the specific resource(s) should not be acquired through an all-source competitive acquisition process. In addition, the utility shall provide a cost-benefit analysis to demonstrate the reason(s) why the public interest would be served by acquiring the specific resource(s) through an alternative method of resource acquisition.	
3611(d)	Although the utility may propose a method for acquiring new utility resources other than all-source competitive bidding, as a prerequisite, the utility shall nonetheless include in its plan filed under rule 3603 the necessary bid policies, RFPs, and model contracts necessary to satisfy the resource need identified under rule 3610 exclusively through all-source competitive bidding.	Volume 3
3611(e)	In the event that the utility proposes an alternative method of resource acquisition that involves the development of a new renewable energy resource or new supply-side resource that the utility shall own as a rate base investment, the utility shall file, simultaneously with its plan submitted under rule 3603, an application for a CPCN for such new resource. The Commission may consolidate, in accordance with the Commission's Rules	N/A

CPUC Rule	Required Information	Where
	of Practice and Procedure, the proceeding addressing that application for a CPCN with the resource planning proceeding. The utility shall provide a detailed estimate of the cost of the proposed facility to be constructed and information on alternatives studied, costs for those alternatives, and criteria used to rank or eliminate those alternatives.	
3611(f)	The utility may participate in a competitive resource acquisition process by proposing the development of a new utility resource that the utility shall own as a rate base investment. The utility shall provide sufficient cost information in support of its proposal such that the Commission can reasonably compare the utility's proposal to alternative bids. In the event a utility proposes a rate base investment, the utility shall also propose how it intends to compare the utility rate based proposal(s) with non-utility bids. The Commission may also address the regulatory treatment of such costs with respect to future recovery.	Volume 3, Company ownership RFP
3611(g)	Each utility shall propose a written bidding policy as part of its filing under rule 3603, including the assumptions, criteria, and models that will be used to solicit and evaluate bids in a fair and reasonable manner. The utility shall specify the competitive acquisition procedures that it intends to use to obtain resources under the utility's plan. The utility shall also propose, and other interested parties may provide input as part of the resource plan proceeding, criteria for evaluating the costs and benefits of resources such as the valuation of emissions and non-energy benefits.	Volume 2, Section 2.16
3611(h)	In the event that the utility proposes to acquire specific resources through an alternative method of resource acquisition that involves the development of a new renewable energy resource or new supply-side resource that the utility shall own as a rate base investment, the utility shall provide the Commission with the following best value employment metric information regarding each resource:	N/A
3611(h)(I)-(IV)	The availability of training programs, including training through apprenticeship programs registered with the United States Department of Labor, Office of Apprenticeship and Training;	Volume 2, Section 2.16
	The employment of Colorado workers as compared to importation of out-of-state workers;	
	Long-term career opportunities; and	
	Industry-standard wages, health care, and pension benefits.	
3604(h)	**Water Resources**	
3604(h)	The annual water consumption for each of the utility's existing generation resources, and the water intensity (in gallons per MWh) of the existing generating system as a whole, as well as the projected water consumption for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its resource plan.	Volume 2, Section 2.18
3604(i)	**RFPs and Model Contracts**	
	The proposed RFP(s) the utility intends to use to solicit bids for energy and capacity resources to be acquired through a competitive acquisition process, including model contracts, pursuant to rule 3616.	Volume 3 (3.1, 3.2, 3.3)

CPUC Rule	Required Information	Where
3604(j)	**Confidential and Highly Confidential Information**	
	A list of the information related to the resource plan proceeding that the utility claims is confidential, and a list of the information related to the resource plan proceeding that the utility claims is highly confidential. The utility shall also list the information that it will provide to owners or developers of a potential resource under paragraphs 3613(a) and (b). The utility shall further explicitly list the protections it proposes for bid prices, other bid details, information concerning a new resource that the utility proposes to build and own as a rate base investment, other modeling inputs and assumptions, and the results of bid evaluation and selection. The protections sought by the utility for these items shall be specified in the motion(s) submitted under paragraph 3603(b). For good cause shown the utility may seek to protect additional information as confidential or highly confidential by filing the appropriate motion under rule 1100 of the Commission's Rules of Practice and Procedure in a timely manner.	Volume 2, Section 2.17
3604(k)	**Alternative Plans**	
	Descriptions of at least three alternate plans that can be used to represent the costs and benefits from increasing amounts of renewable energy resources, demand-side resources, or Section 123 resources as defined in paragraph 3602(q) potentially included in a cost-effective resource plan. One of the alternate plans shall represent a baseline case that describes the costs and benefits of the new utility resources required to meet the utility's needs during the planning period that minimize the net present value of revenue requirements and that complies with the Renewable Energy Standard, 4 CCR 723-3-3650 et seq., as well as with the demand-side resource requirements under § 40-3.2-104, C.R.S. The other alternate plans shall represent alternative combinations of resources that meet the same resource needs as the baseline case but that include proportionately more renewable energy resources, demand-side resources, or Section 123 resources. The utility shall propose a range of possible future scenarios and input sensitivities for the purpose of testing the robustness of the alternate plans under various parameters.	Volume 2, Section 2.13
3604(l)	**Additional Renewable Resources**	
	An assessment of the costs and benefits of the integration of intermittent renewable energy resources on the utility's system, including peer-reviewed studies, consistent with the amounts of renewable energy resources the utility proposes to acquire.	Volume 2, Section 2.14 & 2.18

CPUC Rule	Required Information	Where
3604(m)	**Energy Storage Systems Modeling Assumptions**	
	Modeling assumptions and analytical methodology proposed to assess the costs and benefits of energy storage systems including, but not limited to: integration of intermittent resources; improvement of reliability; reduction in the need for increased generation facilities to meet periods of peak demand; and avoidance, reduction, or deferral of investments.	Volume 2, Section 2.10
3604(n)	**Energy Storage Systems Smaller Than 30 MW**	
	The utility shall propose how energy storage systems smaller than 30 MW in size may be accommodated in the all-source competitive acquisition process.	Volume 2, Section 2.16

Table 2.0-2 Proposed Draft ERP Rules for Which the Company Is Providing Additional Information

Proposed Draft Rule	Proposed Rule Language	Where
3604	**Contents of the Resource Plan**	
3604(l)	An assessment of potential cost-effective early retirements of utility-owned resources with retirement dates during the planning period, including the costs associated with incremental depreciation expenses and estimated operational and capital savings. For each early retirement reviewed, the utility shall describe the replacement resource need, possible system reliability impacts, and corrective actions for such impacts.	Volume 2, Section 2.6
3606	**Electric Energy and Demand Forecasts**	
3606(b)(I)	The base forecast shall reflect the amounts of energy and demand savings from demand side resources previously approved by the Commission; the distributed energy resources expected to be interconnected, both through the utility's Commission-approved plans, and outside of utility plans; expected level of transportation electrification consistent with the base assumption used in the utility's most recent transportation electrification plan filed pursuant to § 40-5-107, C.R.S.	Volume 2, Section 2.2 & 2.14
3606(b)(II)	The utility shall provide a separate forecast of load resulting from non-transportation beneficial electrification during the resource planning period. This forecast shall include sector-specific assumptions used to develop the utility's beneficial electrification forecast.	
3607	**Evaluation (Assessment) of Existing Resources**	
3607(c)	Benchmarking. For the purpose of identifying existing resources that potentially are not performing cost-effectively as compared to other resources available in the market, the utility shall compare the costs and performance of each of its existing supply-side resources greater than 20 MW of nameplate capacity to the costs and performance of the generic resources.	Volume 2, Section 2.5
3607(d)	Ancillary services assessment. The utility shall identify its existing resources that provide various ancillary services necessary to support its distribution and transmission systems, including, but not limited to, black start resources, non-spinning reserves, spinning reserves, regulation and frequency response, reactive power, voltage control, system control, dispatch services, and energy imbalance services.	Volume 2, Section 2.7
3613	**Best Value Employment Metrics**	
3613	Best value employment metric information regarding each proposed new utility resource shall include the following information. (a) The availability of training programs, including training through apprenticeship programs registered with the United States Department of Labor, Office of Apprenticeship and Training. The utility or bidder shall provide, for example and as applicable, the following information for each craft the utility anticipates will work on the project: (I) availability of training programs; (II) the names of specific training programs available; (III) the curriculum of the specific training programs; (IV) the cost of worker training; (V) the duration of the training programs; (VI) the total number of hours of on-the-job training required; (VII) the total number of classroom hours required;	Volume 2, Section 2.16

Proposed Draft Rule	Proposed Rule Language	Where
	(VIII) the licenses and certifications obtained, if any; (IX) a copy of training program standards for each training program; and (X) a statement whether the training programs are United States Department of Labor registered apprenticeship programs and are accredited to award college credits. (b) The employment of Colorado workers as compared to importation of out-of-state workers. The utility or bidder shall provide, for example and as applicable, the following information for each craft the utility anticipates will work on the project: (I) estimated number of workers by job classification; (II) estimated length of time of service, including total man hours, by job classification; (III) percentage of Colorado workers by job classification; and (IV) percentage of project man hours earned by Colorado workers by job classification. (c) Long-term career opportunities. The utility or bidder shall provide, for example and as applicable, the following information for each craft the utility anticipates will work on the project: job classifications, licenses, certifications and skills that will be applied and the long-term career opportunities for each job classification; and (d) Industry-standard wages, health care, and pension benefits. The utility or bidder shall provide, for example and as applicable, the following information for each craft the utility anticipates will work on the project: (I) range of wages by job classification; (II) healthcare benefits by job classification; (III) pension benefits by job classification; (IV) prevailing wages and fringe benefits (healthcare benefits, pension benefits and other compensation) based on industry standards and the current Colorado labor agreements by job classification; and (V) wages and fringe benefits (healthcare benefits, pension benefits and other compensation) by job classification.	

2.1 RESOURCE ACQUISITION AND PLANNING PERIOD

Resource Acquisition Period

Rule 3602(n) defines "Resource Acquisition Period" (or "RAP") as "the first six to ten years of the planning period, in which the utility acquires specific resources to meet projected electric system demand and energy requirements. The RAP begins from the date the utility files its plan with the Commission." In past ERPs, the Company has typically proposed a RAP and discussed the reasons and circumstances that inform a particular RAP timeframe as part of its Phase I filing. For this 2021 ERP, however, the RAP is mandated by statute.

Specifically, SB 19-236 requires that the Company's first ERP it files with the Commission after January 1, 2020 must include a Clean Energy Plan (i.e., this 2021 ERP & CEP) that will achieve the clean energy target of reducing carbon dioxide emissions associated with electricity sales to the Company's electric customers by 80 percent from 2005 levels by 2030. To achieve this clean energy target, SB 19-236 explicitly requires that the Company's 2021 ERP & CEP must utilize a RAP that extends through 2030.

Accordingly, Public Service is utilizing a RAP from the plan filing date of 2021 through 2030.

Planning Period

Rule 3602(k) defines "planning period" as "the future period for which a utility develops its plan, and the period, over which net present value of revenue requirements for resources are calculated... [t]he planning period is twenty to forty years and begins from the date the utility files its plan with the Commission."

Public Service proposes a planning period from the ERP filing date of 2021 extending through 2055, or approximately 35 years, which represents the period following the last year of the RAP (i.e., 2030) through the last year of the proposed 25-year contract term length in the model contracts filed in Volume 3 pursuant to Rule 3604(i). To effectuate a planning period through 2055, the Company used an "end effects" approach in the last years of the planning period. The EnCompass planning model was run through 2050, and the system costs in 2050 were repeated without escalation for the years 2051-2055 and included in the net present value ("NPV") calculations. This is similar to the methodology used by the previous planning model, Strategist, to add cost impacts beyond the years the model was actually run. The model was only run through 2050 for several reasons: (1) adding years to the simulation increases model complexity and run times; (2) most key inputs are not forecasted beyond 2050; and (3) SB 19-236's imposed requirement to meet zero tons of carbon emissions by 2050 creates a relatively subjective portfolio in the latter years when using only generic resources based on today's known technologies.

Although the Proposed Draft Rules have not yet been finalized as of the filing date for this ERP, the Company used the above method for Phase I to align with the planning period requirements set forth in the Proposed Draft Rules. The Company is open to discussion regarding its approach used for Phase I, and generally would prefer a planning period for Phase II that extends no later than 2050, subject to discussion by the parties in this proceeding.

2.2 ELECTRIC ENERGY AND DEMAND FORECASTS

Introduction

In this Section, the Company sets forth detailed electric energy and demand forecast information required by Rule 3606. The energy and demand forecasts represent the Company's expectations for native load, which does not include reductions due to distributed generation, as distributed generation is considered a resource.

Projections of future energy and peak demand are fundamental inputs into Public Service's resource need assessment. As required by Rule 3606(b), Public Service prepared a base forecast and two alternative forecasts for its 2021 ERP & CEP: (1) a high or Roadmap scenario, and (2) a low scenario. The Roadmap scenario reflects data and assumptions based on the Colorado Greenhouse Gas Pollution Reduction Roadmap ("Roadmap") finalized by the State of Colorado on January 14, 2021 (provided as Attachment AKJ-4 to the Direct Testimony of Company witness Alice K. Jackson).

Figures 2.2-1 and 2.2-2 below show the Base, Low, and Roadmap forecasts of native load peak demand and energy graphically. Tables 2.2-1 and 2.2-2 further below show the data supporting Figures 2.2-1 and 2.2-2, respectively. The black line on the figures and grey area on the tables indicate the end of the RAP in 2030.

Public Service projects Base native load peak demand (retail and firm wholesale requirements customers) to grow at a compounded annual rate of 0.3% or an average of 22 MW per year through the RAP. This is slower than the 1.9% growth rate over the last five years. Public Service's Low growth sensitivity for peak demand remains relatively flat through 2030, and the Roadmap sensitivity for peak demand increases at a compounded growth rate of 0.6% per year over the same period.

Public Service projects Base annual energy to increase at a compounded annual growth rate of 0.4% or an average of 130 GWh per year through the RAP. Public Service's Low growth sensitivity for the forecast of annual energy remains flat through 2030, and the Roadmap sensitivity for the forecast of annual energy grows at a compounded rate of 1.2% per year.

The Base peak demand forecast assumes economic growth based on projections from IHS Markit and median summer peak weather conditions. The Base forecast also assumes the electrification of homes continues at the current pace and the rate of electric vehicle ("EV") adoption increases over time. The Low scenario assumes that energy and peak demand grow slower than the Base Case, while the rate of electrification and EV adoption stays the same as the Base Case. The Roadmap scenario assumes a faster pace of electrification and EV adoption than the Base Case.

Figure 2.2-1 Native Load Peak Demand Forecasts

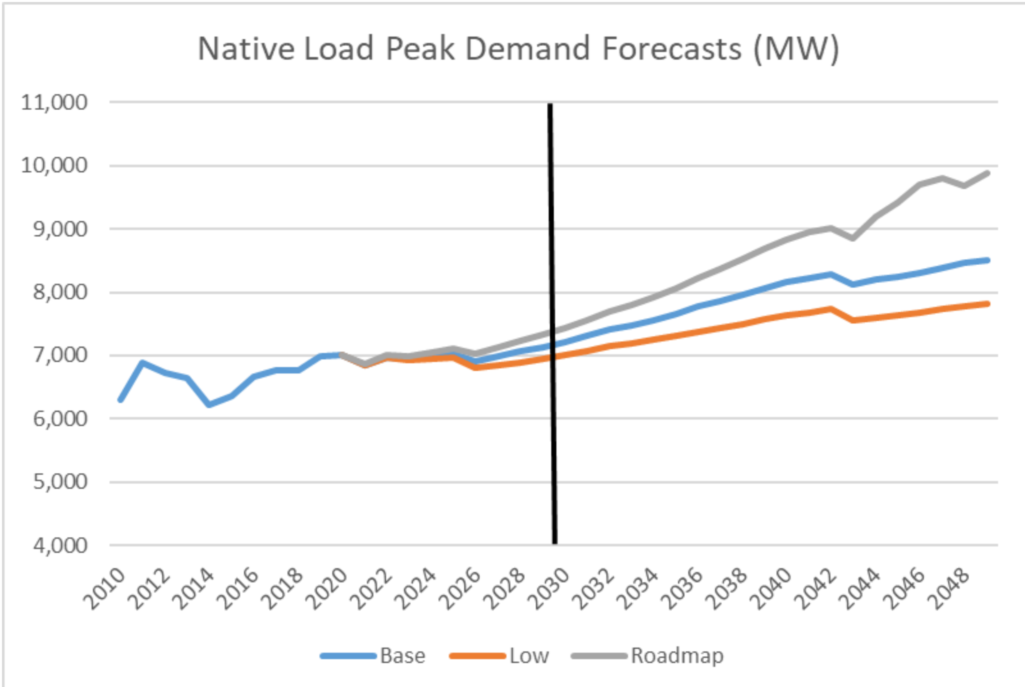


Figure 2.2-2 Native Load Energy Forecasts

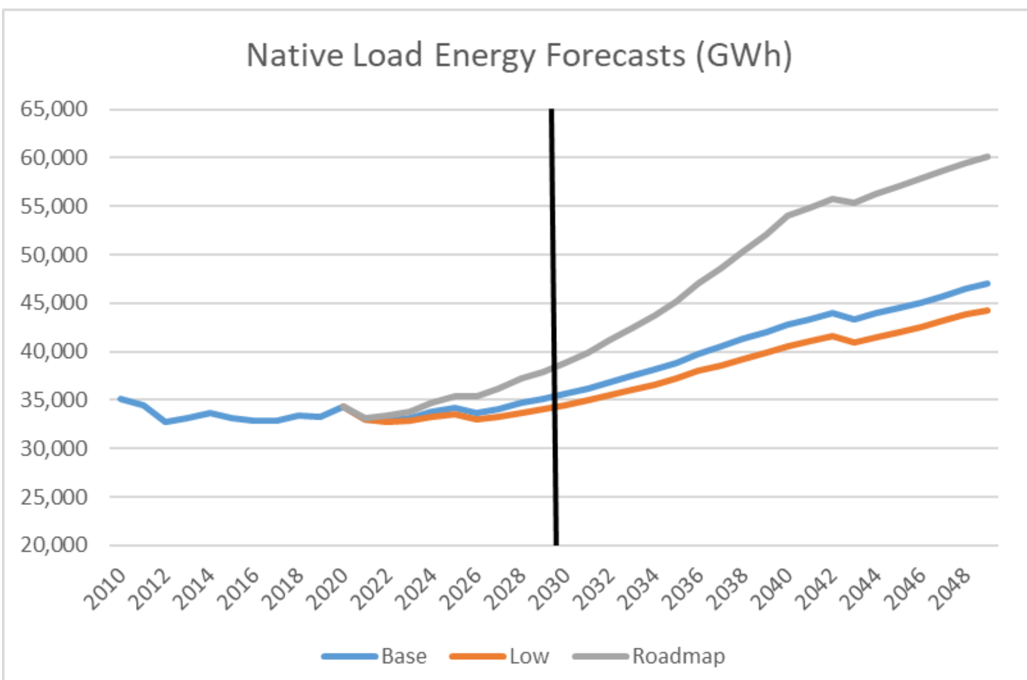


Table 2.2-1 Actual and Forecasted Native Load Peak Demand

	MW			Annual Growth			Compound Growth to/from 2020		
	Base	Low	Roadmap	Base	Low	Roadmap	Base	Low	Roadmap
2010	6,308						1.0%		
2011	6,892			9.3%			0.2%		
2012	6,732			-2.3%			0.5%		
2013	6,643			-1.3%			0.8%		
2014	6,216			-6.4%			2.0%		
2015	6,359			2.3%			1.9%		
2016	6,670			4.9%			1.2%		
2017	6,767			1.5%			1.1%		
2018	6,758			-0.1%			1.8%		
2019	6,992			3.5%			0.1%		
2020	7,002	7,002	7,002	0.1%			0.0%		
2021	6,856	6,856	6,875	-2.1%	-2.1%	-1.8%	-2.1%	-2.1%	-1.8%
2022	6,973	6,973	7,002	1.7%	1.7%	1.8%	-0.2%	-0.2%	0.0%
2023	6,951	6,936	6,996	-0.3%	-0.5%	-0.1%	-0.2%	-0.3%	0.0%
2024	6,978	6,944	7,042	0.4%	0.1%	0.6%	-0.1%	-0.2%	0.1%
2025	7,031	6,960	7,120	0.8%	0.2%	1.1%	0.1%	-0.1%	0.3%
2026	6,906	6,799	7,023	-1.8%	-2.3%	-1.4%	-0.2%	-0.5%	0.0%
2027	6,986	6,855	7,133	1.2%	0.8%	1.6%	0.0%	-0.3%	0.3%
2028	7,063	6,896	7,237	1.1%	0.6%	1.5%	0.1%	-0.2%	0.4%
2029	7,130	6,945	7,328	0.9%	0.7%	1.3%	0.2%	-0.1%	0.5%
2030	7,219	7,012	7,441	1.3%	1.0%	1.5%	0.3%	0.0%	0.6%
2031	7,306	7,076	7,558	1.2%	0.9%	1.6%	0.4%	0.1%	0.7%
2032	7,413	7,148	7,697	1.5%	1.0%	1.8%	0.5%	0.2%	0.8%
2033	7,478	7,196	7,798	0.9%	0.7%	1.3%	0.5%	0.2%	0.8%
2034	7,558	7,251	7,917	1.1%	0.8%	1.5%	0.5%	0.2%	0.9%
2035	7,665	7,319	8,067	1.4%	0.9%	1.9%	0.6%	0.3%	0.9%
2036	7,774	7,379	8,224	1.4%	0.8%	1.9%	0.7%	0.3%	1.0%
2037	7,862	7,437	8,363	1.1%	0.8%	1.7%	0.7%	0.4%	1.0%
2038	7,963	7,500	8,519	1.3%	0.9%	1.9%	0.7%	0.4%	1.1%
2039	8,069	7,573	8,686	1.3%	1.0%	2.0%	0.7%	0.4%	1.1%
2040	8,159	7,631	8,840	1.1%	0.8%	1.8%	0.8%	0.4%	1.2%
2041	8,216	7,679	8,962	0.7%	0.6%	1.4%	0.8%	0.4%	1.2%
2042	8,285	7,731	9,005	0.8%	0.7%	0.5%	0.8%	0.5%	1.2%
2043	8,129	7,555	8,855	-1.9%	-2.3%	-1.7%	0.7%	0.3%	1.0%
2044	8,195	7,593	9,195	0.8%	0.5%	3.8%	0.7%	0.3%	1.1%
2045	8,245	7,636	9,419	0.6%	0.6%	2.4%	0.7%	0.3%	1.2%
2046	8,313	7,686	9,702	0.8%	0.7%	3.0%	0.7%	0.4%	1.3%
2047	8,389	7,741	9,795	0.9%	0.7%	1.0%	0.7%	0.4%	1.3%
2048	8,461	7,783	9,690	0.9%	0.5%	-1.1%	0.7%	0.4%	1.2%
2049	8,509	7,822	9,882	0.6%	0.5%	2.0%	0.7%	0.4%	1.2%

Table 2.2-2 Actual and Forecasted Annual Native Load Energy

	GWh			Annual Growth			Compound Growth to/from 2020		
	Base	Low	Roadmap	Base	Low	Roadmap	Base	Low	Roadmap
2010	35,123						-0.2%		
2011	34,498			-1.8%			-0.1%		
2012	32,734			-5.1%			0.6%		
2013	33,143			1.2%			0.5%		
2014	33,666			1.6%			0.3%		
2015	33,139			-1.6%			0.7%		
2016	32,856			-0.9%			1.1%		
2017	32,929			0.2%			1.4%		
2018	33,363			1.3%			1.4%		
2019	33,282			-0.2%			3.1%		
2020	34,319	34,319	34,319	3.1%			0.0%		
2021	33,010	33,010	33,188	-3.8%	-3.8%	-3.3%	-3.8%	-3.8%	-3.3%
2022	32,929	32,745	33,352	-0.2%	-0.8%	0.5%	-2.0%	-2.3%	-1.4%
2023	33,151	32,874	33,819	0.7%	0.4%	1.4%	-1.1%	-1.4%	-0.5%
2024	33,766	33,341	34,702	1.9%	1.4%	2.6%	-0.4%	-0.7%	0.3%
2025	34,170	33,554	35,452	1.2%	0.6%	2.2%	-0.1%	-0.5%	0.7%
2026	33,737	32,965	35,421	-1.3%	-1.8%	-0.1%	-0.3%	-0.7%	0.5%
2027	34,131	33,255	36,234	1.2%	0.9%	2.3%	-0.1%	-0.4%	0.8%
2028	34,685	33,652	37,181	1.6%	1.2%	2.6%	0.1%	-0.2%	1.0%
2029	35,104	34,015	37,951	1.2%	1.1%	2.1%	0.3%	-0.1%	1.1%
2030	35,627	34,470	38,826	1.5%	1.3%	2.3%	0.4%	0.0%	1.2%
2031	36,178	34,950	39,883	1.5%	1.4%	2.7%	0.5%	0.2%	1.4%
2032	36,895	35,535	41,162	2.0%	1.7%	3.2%	0.6%	0.3%	1.5%
2033	37,462	36,060	42,351	1.5%	1.5%	2.9%	0.7%	0.4%	1.6%
2034	38,118	36,635	43,695	1.8%	1.6%	3.2%	0.8%	0.5%	1.7%
2035	38,899	37,276	45,238	2.0%	1.7%	3.5%	0.8%	0.6%	1.9%
2036	39,805	37,980	46,972	2.3%	1.9%	3.8%	0.9%	0.6%	2.0%
2037	40,516	38,592	48,575	1.8%	1.6%	3.4%	1.0%	0.7%	2.1%
2038	41,313	39,249	50,333	2.0%	1.7%	3.6%	1.0%	0.7%	2.2%
2039	42,069	39,889	52,122	1.8%	1.6%	3.6%	1.1%	0.8%	2.2%
2040	42,823	40,537	53,976	1.8%	1.6%	3.6%	1.1%	0.8%	2.3%
2041	43,379	41,084	54,858	1.3%	1.3%	1.6%	1.1%	0.9%	2.3%
2042	44,002	41,668	55,778	1.4%	1.4%	1.7%	1.1%	0.9%	2.2%
2043	43,298	40,917	55,382	-1.6%	-1.8%	-0.7%	1.0%	0.8%	2.1%
2044	43,969	41,485	56,346	1.5%	1.4%	1.7%	1.0%	0.8%	2.1%
2045	44,466	41,976	57,071	1.1%	1.2%	1.3%	1.0%	0.8%	2.1%
2046	45,091	42,561	57,839	1.4%	1.4%	1.3%	1.1%	0.8%	2.0%
2047	45,762	43,180	58,623	1.5%	1.5%	1.4%	1.1%	0.9%	2.0%
2048	46,520	43,824	59,516	1.7%	1.5%	1.5%	1.1%	0.9%	2.0%
2049	46,991	44,286	60,181	1.0%	1.1%	1.1%	1.1%	0.9%	2.0%

Economic Conditions and Outlook

Public Service used data from the IHS Markit June 2020 economic outlook to develop its ERP forecasts. Specifically, the Company tracked key indicators for the metropolitan areas located within its service territory. These key indicators include population, real personal income, non-farm employment, and gross metropolitan product ("GMP").

The economy of the Company's service territory showed strong growth in the latter half of the 2010s, before contracting in 2020 due to the COVID-19 pandemic. GMP grew, on average, 4.0% from 2014-2019 before declining an expected 8.9% in 2020. Job growth was also robust, averaging 2.6% from 2014-2019 before declining an expected 14.1% in 2020. Real personal income contracted an expected 2.2% in 2020 after averaging 4.2% growth in the preceding 5 years. Population growth slowed to 1.1% in 2020.

IHS Markit's June 2020 outlook expects the economic rebound to begin in 2021 and continue through the 2020s, before returning to long-run economic growth rates. Average growth for the 2020-2030 time period is expected to be strong as the economy rebounds from the effects of the COVID-19 pandemic. Long-run growth rates for these key indicators are slightly slower than the growth rates seen from 2014-2019.

Table 2.2-3 summarizes the economic history and outlook for the key economic drivers.

Table 2.2-3 Growth Rates for Key Economic Drivers

	Average Annual Growth			
	Employment	Population	GMP	Real Pers Inc
2014-2019	2.6%	1.5%	4.0%	4.2%
2019-2020	-14.1%	1.1%	-8.9%	-2.2%
2020-2030	2.7%	1.1%	3.5%	3.1%
2020-2049	1.5%	0.9%	2.7%	2.6%

Peak Demand Trends and Forecast

Table 2.2-4 shows the actual and forecasted retail and wholesale peak demands.

Table 2.2-4 Peak Demand Forecast – Base Case, Retail, and Wholesale

	MW			Annual Growth			Compound Growth to/from 2020		
	Retail	Wholesale	Total	Retail	Wholesale	Total	Retail	Wholesale	Total
2010	5,573	736	6,308				1.0%	1.2%	1.0%
2011	5,848	1,044	6,892	4.9%	41.9%	9.3%	0.6%	-2.6%	0.2%
2012	6,163	569	6,732	5.4%	-45.5%	-2.3%	0.0%	4.8%	0.5%
2013	5,875	768	6,643	-4.7%	35.0%	-1.3%	0.7%	1.0%	0.8%
2014	5,748	468	6,216	-2.2%	-39.0%	-6.4%	1.2%	9.9%	2.0%
2015	5,729	630	6,359	-0.3%	34.5%	2.3%	1.5%	5.6%	1.9%
2016	6,068	602	6,670	5.9%	-4.4%	4.9%	0.4%	8.2%	1.2%
2017	6,238	530	6,767	2.8%	-12.0%	1.5%	-0.3%	16.0%	1.1%
2018	6,191	567	6,758	-0.8%	7.1%	-0.1%	-0.1%	20.7%	1.8%
2019	6,192	801	6,992	0.0%	41.1%	3.5%	-0.3%	3.2%	0.1%
2020	6,176	826	7,002	-0.3%	3.2%	0.1%	0.0%	0.0%	0.0%
2021	6,414	443	6,856	3.8%	-46.4%	-2.1%	3.8%	-46.4%	-2.1%
2022	6,562	411	6,973	2.3%	-7.2%	1.7%	3.1%	-29.5%	-0.2%
2023	6,579	372	6,951	0.3%	-9.5%	-0.3%	2.1%	-23.4%	-0.2%
2024	6,599	379	6,978	0.3%	1.9%	0.4%	1.7%	-17.7%	-0.1%
2025	6,643	388	7,031	0.7%	2.5%	0.8%	1.5%	-14.0%	0.1%
2026	6,725	180	6,906	1.2%	-53.5%	-1.8%	1.4%	-22.4%	-0.2%
2027	6,806	181	6,986	1.2%	0.1%	1.2%	1.4%	-19.5%	0.0%
2028	6,882	182	7,063	1.1%	0.7%	1.1%	1.4%	-17.2%	0.1%
2029	6,947	183	7,130	0.9%	0.8%	0.9%	1.3%	-15.4%	0.2%
2030	7,035	184	7,219	1.3%	0.4%	1.3%	1.3%	-13.9%	0.3%
2031	7,128	178	7,306	1.3%	-3.0%	1.2%	1.3%	-13.0%	0.4%
2032	7,212	201	7,413	1.2%	12.7%	1.5%	1.3%	-11.1%	0.5%
2033	7,275	203	7,478	0.9%	1.0%	0.9%	1.3%	-10.2%	0.5%
2034	7,353	205	7,558	1.1%	1.1%	1.1%	1.3%	-9.5%	0.5%
2035	7,457	208	7,665	1.4%	1.1%	1.4%	1.3%	-8.8%	0.6%
2036	7,564	210	7,774	1.4%	1.1%	1.4%	1.3%	-8.2%	0.7%
2037	7,649	212	7,862	1.1%	1.2%	1.1%	1.3%	-7.7%	0.7%
2038	7,748	215	7,963	1.3%	1.2%	1.3%	1.3%	-7.2%	0.7%
2039	7,852	217	8,069	1.3%	1.2%	1.3%	1.3%	-6.8%	0.7%
2040	7,939	220	8,159	1.1%	1.2%	1.1%	1.3%	-6.4%	0.8%
2041	7,993	223	8,216	0.7%	1.3%	0.7%	1.2%	-6.0%	0.8%
2042	8,060	226	8,285	0.8%	1.3%	0.8%	1.2%	-5.7%	0.8%
2043	8,129	-	8,129	0.9%		-1.9%	1.2%		0.7%
2044	8,195	-	8,195	0.8%		0.8%	1.2%		0.7%
2045	8,245	-	8,245	0.6%		0.6%	1.2%		0.7%
2046	8,313	-	8,313	0.8%		0.8%	1.1%		0.7%
2047	8,389	-	8,389	0.9%		0.9%	1.1%		0.7%
2048	8,461	-	8,461	0.9%		0.9%	1.1%		0.7%
2049	8,509	-	8,509	0.6%		0.6%	1.1%		0.7%

Native load peak demand in Public Service's service territory has advanced 643 MW during the past five years, driven primarily by retail growth of 447 MW. Total peak demand has averaged 1.9% growth and retail peak demand has increased an average of 1.5% over that time. Wholesale demand has increased 196 MW over the same time period, but the growth is driven by Comanche 3 being offline, resulting in Public Service serving more load to the Rural Electric Association ("REA") participants at the time of the 2020 peak. After accounting for the additional load served due to Comanche 3 being offline, wholesale load has declined approximately 50 MW since 2015.

Peak demand is expected to increase slowly through the RAP, as the growth in retail load more than offsets the declines in wholesale. In total, load is expected to grow on average 0.3% through 2030, with retail growing at an average rate of 1.3%.

Energy Trends and Forecast

Table 2.2-5 shows the actual and forecasted retail and wholesale energy amounts (or native energy).

The decrease in wholesale energy in 2011 is due to the participation of Intermountain Rural Electric Association ("IREA") and Holy Cross Energy in the Comanche 3 project. The decrease in 2012 is attributable to the termination of the Company's wholesale contract with Black Hills Energy. The large increase in wholesale energy in 2020 is due to Comanche 3 being offline, which results in Public Service's contractual requirement to serve additional load for the partners.

Native energy has shown moderate growth from 2015-2020, increasing at an average rate of 0.7% over that time. The growth is driven by wholesale energy, as retail energy has remained relatively flat for that time period.

Native energy is expected to increase slowly through the RAP, at an average rate of 0.4% per year. Retail growth of 1.1% is offsetting the declines in wholesale energy due to the expiration of contracts. Longer term, retail growth is expected to increase due to the adoption of EVs, as discussed in later sections.

Table 2.2-5 Native Energy Forecast – Base Case, Retail, and Wholesale

	GWh			Annual Growth			Compound Growth to/from 2020		
	Retail	Wholesale	Total	Retail	Wholesale	Total	Retail	Wholesale	Total
2010	30,079	5,044	35,123				0.2%	-3.6%	-0.2%
2011	30,160	4,339	34,498	0.3%	-14.0%	-1.8%	0.2%	-2.3%	-0.1%
2012	30,307	2,427	32,734	0.5%	-44.1%	-5.1%	0.2%	4.7%	0.6%
2013	30,588	2,555	33,143	0.9%	5.3%	1.2%	0.1%	4.6%	0.5%
2014	31,008	2,658	33,666	1.4%	4.1%	1.6%	-0.1%	4.7%	0.3%
2015	30,909	2,229	33,139	-0.3%	-16.1%	-1.6%	-0.1%	9.5%	0.7%
2016	30,884	1,973	32,856	-0.1%	-11.5%	-0.9%	-0.1%	15.5%	1.1%
2017	30,808	2,122	32,929	-0.2%	7.6%	0.2%	0.0%	18.3%	1.4%
2018	31,250	2,113	33,363	1.4%	-0.4%	1.3%	-0.7%	28.9%	1.4%
2019	31,193	2,089	33,282	-0.2%	-1.2%	-0.2%	-1.2%	68.0%	3.1%
2020	30,810	3,509	34,319	-1.2%	68.0%	3.1%	0.0%	0.0%	0.0%
2021	30,727	2,283	33,010	-0.3%	-34.9%	-3.8%	-0.3%	-34.9%	-3.8%
2022	30,950	1,979	32,929	0.7%	-13.3%	-0.2%	0.2%	-24.9%	-2.0%
2023	31,246	1,905	33,151	1.0%	-3.8%	0.7%	0.5%	-18.4%	-1.1%
2024	31,696	2,071	33,766	1.4%	8.7%	1.9%	0.7%	-12.4%	-0.4%
2025	32,156	2,014	34,170	1.5%	-2.7%	1.2%	0.9%	-10.5%	-0.1%
2026	32,618	1,120	33,737	1.4%	-44.4%	-1.3%	1.0%	-17.3%	-0.3%
2027	33,001	1,129	34,131	1.2%	0.9%	1.2%	1.0%	-15.0%	-0.1%
2028	33,544	1,141	34,685	1.6%	1.0%	1.6%	1.1%	-13.1%	0.1%
2029	33,952	1,152	35,104	1.2%	1.0%	1.2%	1.1%	-11.6%	0.3%
2030	34,464	1,163	35,627	1.5%	0.9%	1.5%	1.1%	-10.5%	0.4%
2031	35,034	1,144	36,178	1.7%	-1.6%	1.5%	1.2%	-9.7%	0.5%
2032	35,739	1,156	36,895	2.0%	1.0%	2.0%	1.2%	-8.8%	0.6%
2033	36,294	1,168	37,462	1.6%	1.1%	1.5%	1.3%	-8.1%	0.7%
2034	36,937	1,181	38,118	1.8%	1.1%	1.8%	1.3%	-7.5%	0.8%
2035	37,705	1,193	38,899	2.1%	1.1%	2.0%	1.4%	-6.9%	0.8%
2036	38,599	1,206	39,805	2.4%	1.1%	2.3%	1.4%	-6.5%	0.9%
2037	39,297	1,219	40,516	1.8%	1.1%	1.8%	1.4%	-6.0%	1.0%
2038	40,081	1,232	41,313	2.0%	1.1%	2.0%	1.5%	-5.6%	1.0%
2039	40,824	1,245	42,069	1.9%	1.1%	1.8%	1.5%	-5.3%	1.1%
2040	41,564	1,259	42,823	1.8%	1.1%	1.8%	1.5%	-5.0%	1.1%
2041	42,106	1,273	43,379	1.3%	1.1%	1.3%	1.5%	-4.7%	1.1%
2042	42,715	1,287	44,002	1.4%	1.1%	1.4%	1.5%	-4.5%	1.1%
2043	43,298	-	43,298	1.4%		-1.6%	1.5%		1.0%
2044	43,969	-	43,969	1.5%		1.5%	1.5%		1.0%
2045	44,466	-	44,466	1.1%		1.1%	1.5%		1.0%
2046	45,091	-	45,091	1.4%		1.4%	1.5%		1.1%
2047	45,762	-	45,762	1.5%		1.5%	1.5%		1.1%
2048	46,520	-	46,520	1.7%		1.7%	1.5%		1.1%
2049	46,991	-	46,991	1.0%		1.0%	1.5%		1.1%

Electric Vehicles

In addition to the Electric Energy and Demand Forecast information required by Rule 3606, the Company has also addressed information contemplated by Proposed Draft Rule 3606(b)(I). Proposed Draft Rule 3606(b)(I) was developed in response to Decision No. C19-0822-I in Proceeding No. 19R-0096E, in which the Commission requested that the Colorado Energy Office ("CEO") work with interested stakeholders to develop consensus on answers to a set of questions addressing whether and how Governor Polis' Roadmap to 100% Renewable Energy by 2040 and Bold Climate Action should be addressed in the Commission's ERP Rules. Accordingly, in late 2019 CEO facilitated a process through which numerous stakeholders reached consensus on several proposed rules that were filed on December 20, 2019 in Proceeding No. 19R-0096E,[3] including Proposed Draft Rule 3606(b)(I), which states as follows:

> The base forecast shall reflect the amounts of energy and demand savings from demand-side resources previously approved by the Commission; the distributed energy resources expected to be interconnected, both through the utility's Commission-approved plans, and outside of utility plans; expected level of transportation electrification consistent with the base assumption used in the utility's most recent transportation electrification plan filed pursuant to § 40-5-107, C.R.S.

Although this Proposed Draft Rule will not be ultimately adopted by the Commission, given the consensus nature of this Proposed Draft Rule and the interest of the Commission and stakeholders in transportation electrification impacts on the load forecast, the Company incorporated this information as described below.

<u>Light Duty Vehicles ("LDV")</u>

The Base Case and Low scenario EV forecasts estimate EV adoption using two modeling techniques: (1) Bass diffusion modeling, and (2) economic modeling. After establishing forecasts through both methods, we average the results to estimate EV adoption.

- *Bass Diffusion Modeling.* Bass diffusion models are used to describe technology adoptions patterns in an existing market through an "S" shaped diffusion

[3] *See* Joint Supplemental Comments of Colorado Energy Office, the Southwest Energy Efficiency Project ("SWEEP"), Colorado Energy Consumers ("CEC"), Vote Solar, Southwest Generation, the Office of Consumer Counsel ("OCC"), Ms. Leslie Glustrom, Sierra Club, Western Resource Advocates ("WRA"), Colorado Independent Energy Association ("CIEA"), City of Boulder, Interwest Energy Alliance, and Colorado Solar and Storage Association ("COSSA") & Solar Energy Industries Association ("SEIA") filed on December 20, 2019 in Proceeding No. 19R-0096E.

characteristic. The Bass diffusion model approach is calibrated using state-specific historical EV sales.

- *Economic Modeling.* Economic models use simple payback analysis to estimate potential adoption, incorporating factors such as battery prices, tax incentives, fuel savings, and others.

Additionally, we have incorporated into both the Bass diffusion and economic models a factor for the percentage of vehicles in urban and rural areas. Presently, higher adoption is occurring in urban areas with the rural areas anticipated to ramp up slowly. The estimates are also sensitive to several exogenous variables because battery market dynamics are a significant factor in the cost of EVs. These variables may include policy, technology, manufacturing supply chain, and geopolitical factors, among others.

Since we are in the early stages of EV adoption, the nascent market brings significant uncertainties. There is a broad range of possible outcomes, and forecasts could be volatile. We would expect that as the market continues to grow and we continue to update our models with new data, our future estimates will be increasingly robust.

The Roadmap scenario was not modeled using the same methodologies used for the Base Case and Low scenarios. The Roadmap scenario reflects data produced in the State of Colorado's Roadmap report. Calculations were then made to estimate the approximate number of vehicles and consumption specific to Public Service's territory.

Medium and Heavy Duty Vehicles

The Company utilizes a medium duty vehicle ("MDV") and heavy duty vehicle ("HDV") forecast that was produced by a third-party consultant (Navigant, now Guidehouse). This forecast included a high, low, and base case scenario for Public Service's service territory in Colorado. The Company utilized Navigant's base case forecast to inform the Company's Low and Base Case scenarios.

Similar to the analysis of LDVs, the MDV and HDV data utilized in the Company's Roadmap scenario reflects data produced in the State of Colorado's Roadmap report. Calculations were then made to estimate the approximate number of vehicles and consumption within Public Service's territory.

EV Load Shapes

The Base Case and Low scenarios utilize an unmanaged charging profile through 2021 and utilize a managed charging profile for the remainder of the forecast period beginning in 2022. The managed and unmanaged charging profiles for LDV were produced by a third-party consultant (E3), while the MDV/HDV profiles were produced by another third-party consultant (Navigant, now Guidehouse).

Table 2.2-6 below shows forecasted EV adoption under the Base Case/Low and Roadmap scenarios.

Table 2.2-6 Number of EVs by Scenario

	Base/Low				Roadmap			
	LDV	MDV	HDV	Total	LDV	MDV	HDV	Total
2020	30,450	0	38	30,488	53,318	-	-	53,318
2021	41,284	0	40	41,324	89,230	115	240	89,585
2022	61,323	0	43	61,366	143,000	342	649	143,990
2023	99,195	28	54	99,277	211,731	665	1,053	213,449
2024	135,844	102	78	136,024	296,626	1,092	1,463	299,181
2025	169,221	234	118	169,573	396,952	1,615	1,965	400,532
2026	202,972	440	187	203,598	510,156	2,231	2,548	514,935
2027	244,725	749	295	245,769	632,327	2,938	3,215	638,479
2028	298,325	1,146	448	299,919	759,435	3,739	3,980	767,155
2029	365,780	1,645	637	368,061	889,507	4,640	4,865	899,012
2030	451,342	2,298	879	454,520	1,039,542	5,644	5,883	1,051,068
2031	539,005	3,050	1,159	543,215	1,198,075	6,808	7,087	1,211,970
2032	629,944	3,878	1,473	635,295	1,361,707	8,138	8,513	1,378,358
2033	724,350	4,759	1,815	730,924	1,530,153	9,654	10,184	1,549,990
2034	820,722	5,680	2,185	828,586	1,702,666	11,401	12,090	1,726,157
2035	918,023	6,633	2,580	927,236	1,878,654	13,454	14,176	1,906,284
2036	1,016,583	7,613	3,001	1,027,197	2,057,220	15,888	16,368	2,089,476
2037	1,116,434	8,619	3,447	1,128,500	2,237,645	18,704	18,612	2,274,961
2038	1,217,637	9,648	3,919	1,231,204	2,419,205	21,797	20,884	2,461,886
2039	1,319,901	10,700	4,418	1,335,019	2,601,490	25,040	23,180	2,649,711
2040	1,423,299	11,897	4,996	1,440,192	2,784,206	28,375	25,509	2,838,090
2041	1,528,025	13,095	5,573	1,546,693	2,958,878	31,493	27,693	3,018,065
2042	1,633,833	14,292	6,151	1,654,276	3,125,217	34,484	29,774	3,189,475
2043	1,740,658	15,489	6,728	1,762,876	3,283,111	37,362	31,758	3,352,231
2044	1,849,021	16,687	7,306	1,873,013	3,433,259	40,135	33,652	3,507,047
2045	1,959,096	17,884	7,883	1,984,863	3,575,535	42,810	35,461	3,653,806
2046	2,070,891	19,081	8,461	2,098,433	3,704,777	45,385	37,188	3,787,350
2047	2,184,398	20,279	9,038	2,213,714	3,830,582	47,860	38,833	3,917,275
2048	2,285,079	21,476	9,615	2,316,170	3,953,421	50,229	40,394	4,044,044
2049	2,369,419	22,673	10,193	2,402,285	4,070,819	52,487	41,865	4,165,171
2050	2,454,355	23,870	10,770	2,488,996	4,198,355	54,627	43,234	4,296,216

Beneficial Electrification Forecast

The Company has also addressed information contemplated by Proposed Draft Rule 3606(b)(II), which was likewise developed through stakeholder consensus in response to Decision No. C19-0822-I in Proceeding No. 19R-0096E. Proposed Draft Rule 3606(b)(II) states as follows:

> The utility shall provide a separate forecast of load resulting from non-transportation beneficial electrification during the resource planning period. This forecast shall include sector-specific assumptions used to develop the utility's beneficial electrification forecast.

Although this Proposed Draft Rule will not be ultimately adopted by the Commission, given the consensus nature of this Proposed Draft Rule and the interest of the Commission and stakeholders in non-transportation beneficial electrification impacts on the load forecast, the Company is providing this additional information as described below.

The Company developed two modeling assumptions to be used in the forecasting scenarios. The first assumption was the continuation of beneficial electrification growth consistent with historic growth. This assumption was applied to both the Base Case and Low scenarios and reflects uncertainty around how specific policy implementations could ultimately impact the levels of adoption. For the Roadmap scenario, the Company relied upon a July 2020 analysis by GDS Consulting that found current technical and economic potential is highest within the area of residential and commercial building electrification. Specifically, due to factors such as advancements in heat pump technology, residential growth rates in space and water heating are up to two times greater under the Roadmap scenario relative to the Base Case scenario.

The relative saturation levels of beneficial electrification within the residential and commercial sectors provided in Table 2.2-7 below are a forecast of the percent of customers that utilize electricity as the primary fuel source for space heating and water heating end uses. Given that heat pumps are currently in the very early stages of adoption, the actual electrical appliances that will be used are expected to be a combination of electric resistance heaters, electric boilers, and electric resistance storage water heaters, as well as air source heat pumps and heat pump storage water heaters.

In order to estimate an overall load shape for electric space and water heating, the Electric Power Research Institute ("EPRI") Load Shape Library 8.0 was referenced. The EPRI Load Shape Library provides a representative electric load shape by end use aggregated over North American Electric Reliability Corporation ("NERC") regions, which for the purposes of this analysis was the Southwest Power Pool ("SPP") region.

Table 2.2-7 Appliance Saturations by Scenario

	Base/Low				Roadmap			
	Residential Space Heat	Residential Water Heat	Commercial Space Heat	Commercial Water Heat	Residential Space Heat	Residential Water Heat	Commercial Space Heat	Commercial Water Heat
2020	15.0%	13.0%	30.0%	50.0%	15.0%	13.0%	30.0%	50.0%
2021	15.2%	13.1%	30.7%	51.1%	16.2%	14.2%	30.4%	50.6%
2022	15.3%	13.3%	30.6%	51.0%	17.5%	15.6%	30.0%	50.0%
2023	15.4%	13.4%	30.6%	51.0%	18.9%	17.1%	29.7%	49.5%
2024	15.6%	13.5%	30.5%	50.9%	20.4%	18.7%	29.4%	48.9%
2025	15.8%	13.7%	30.5%	50.9%	22.0%	20.5%	29.0%	48.4%
2026	15.9%	13.8%	30.6%	51.1%	23.8%	22.4%	28.9%	48.1%
2027	16.1%	14.0%	30.8%	51.3%	25.7%	24.6%	28.7%	47.9%
2028	16.3%	14.1%	30.9%	51.5%	27.8%	26.9%	28.6%	47.6%
2029	16.5%	14.3%	31.1%	51.8%	30.1%	29.5%	28.4%	47.3%
2030	16.7%	14.4%	31.2%	52.0%	32.5%	32.4%	28.3%	47.1%
2031	16.8%	14.6%	31.4%	52.3%	35.0%	35.8%	31.1%	49.6%
2032	17.0%	14.8%	31.5%	52.6%	37.7%	39.6%	34.2%	52.2%
2033	17.2%	14.9%	31.7%	52.8%	40.6%	43.8%	37.6%	54.9%
2034	17.5%	15.1%	31.9%	53.1%	43.7%	48.5%	41.4%	57.8%
2035	17.7%	15.3%	32.0%	53.4%	47.1%	53.7%	45.5%	60.9%
2036	17.9%	15.5%	32.2%	53.7%	50.8%	59.5%	50.1%	64.1%
2037	18.1%	15.7%	32.4%	54.0%	54.8%	65.9%	55.1%	67.5%
2038	18.4%	15.9%	32.6%	54.3%	59.1%	73.0%	60.6%	71.1%
2039	18.6%	16.1%	32.8%	54.6%	63.7%	80.9%	66.7%	74.9%
2040	18.9%	16.4%	33.0%	54.9%	68.7%	89.6%	73.4%	78.9%
2041	19.1%	16.6%	33.2%	55.3%	70.7%	90.5%	75.4%	80.6%
2042	19.4%	16.8%	33.4%	55.6%	72.8%	91.4%	77.5%	82.4%
2043	19.7%	17.0%	33.6%	55.9%	75.0%	92.4%	79.6%	84.2%
2044	19.9%	17.3%	33.8%	56.3%	77.3%	93.3%	81.7%	86.0%
2045	20.2%	17.5%	34.0%	56.6%	79.6%	94.3%	84.0%	87.9%
2046	20.5%	17.8%	34.2%	57.0%	82.1%	95.3%	86.3%	89.8%
2047	20.8%	18.0%	34.4%	57.3%	84.6%	96.4%	88.6%	91.8%
2048	21.1%	18.3%	34.6%	57.7%	87.2%	97.4%	91.1%	93.9%
2049	21.4%	18.6%	34.8%	58.1%	89.9%	98.6%	93.6%	96.0%
2050	21.7%	18.8%	35.1%	58.4%	92.7%	99.6%	96.2%	98.1%

Wholesale Forecast

Methodology

Forecasts of sales for each REA and municipality are received directly from the customers. The sales are then adjusted for losses to develop the energy forecast.

Forecasts of peak demand for each REA and municipality are received from the respective wholesale customers.

Summary

As previously shown in Tables 2.2-4 and 2.2-5, wholesale energy and demand is expected to decline through the forecast period. IREA is expected to no longer take power from Public Service by the end of 2025, and the remaining customers drop off of the system after 2042. Figures 2.2-3 and 2.2-4 below graphically depict the energy and demand forecasts for wholesale.

Figure 2.2-3 Wholesale Coincident Peak Demand Forecast

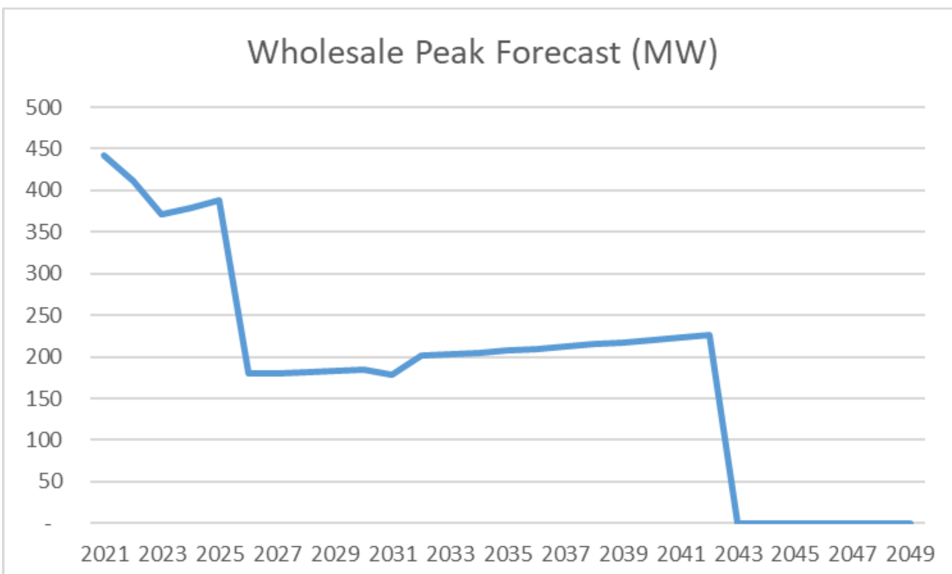
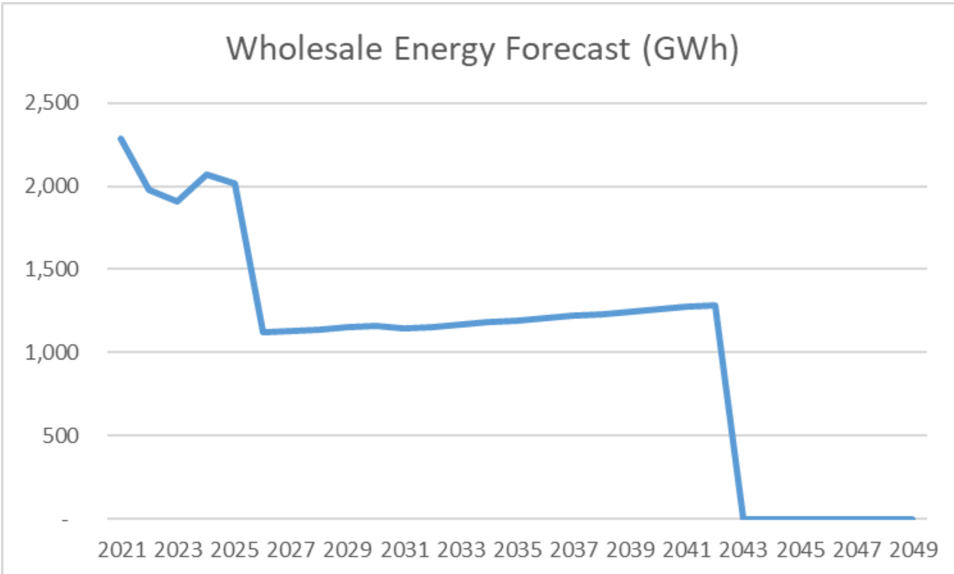


Figure 2.2-4 Wholesale Energy Forecast



<u>Base Retail Forecast</u>

<u>Methodology</u>

Public Service uses monthly historical customer, sales, and peak demand data by rate class to develop its forecasts. Historical and forecasted economic and demographic data are obtained from IHS Markit. Historical weather data is obtained from the National Oceanic and Atmospheric Administration ("NOAA") and based on weather at Denver International Airport and Stapleton.

<u>Forecasted Weather Assumptions</u>

The Company uses a 10-year average of monthly Cooling Degree Days ("CDDs") and Heating Degree Days ("HDDs") at Denver International Airport in its sales models. For this forecast, the 10-year period is from 2010-2019. The Company uses a 30-year average of monthly maximum daily CDDs and HDDs for its peak demand models, based on data at Stapleton. For this forecast, the 30-year period is 1990-2019.

Sales and Energy Forecast

Public Service's residential sales and commercial and industrial sales forecasts are developed using a Statistically-Adjusted End-Use ("SAE") modeling approach. The SAE method entails specifying energy use as a function of the primary end-use variables (heating, cooling, and base use) and the factors that affect these end-use energy requirements.

The SAE residential sales forecast is calculated as the product of average use and customer forecasts. The SAE modeling approach consists of regressions for average use per customer and number of customers. The use per customer regression model is estimated using monthly historical sales per customer, weather, economics, price, and appliance saturation and efficiency trend data. Customer growth is strongly correlated with growth in service territory population. Therefore, the number of customers is forecasted as a function of population projections.

End-use concepts are incorporated in the average use per customer model. Average use is defined as a function of heating, cooling, and base use requirements, as shown below. The term *e* is the model error term.

Average Use = Heating + Cooling + Base + *e*

Each of these elements of average use is defined in terms of both an appliance index variable, which indicates relative saturation and efficiency of the stock of appliances, and a utilization variable, which reflects how the stock is utilized. The end-use variables are defined as:

Heating = HeatIndex * HeatUse
Cooling = CoolIndex * CoolUse
Base = BaseIndex * BaseUse

The indices are calculated as the ratio of the appliance saturation and average efficiency of the existing stock. The indices reflect both changes in saturation resulting from end-use competition and improvements in appliance efficiency standards. For example, if gas heating gains market share, the electric heating saturation will decline, resulting in a decline in the heating index variable. Similarly, improvements in electric heating efficiency will also contribute to a lower heating index. The trend towards greater saturation of central air conditioning has the opposite effect, contributing to an increasing cooling index over time. Air conditioning efficiency gains mitigate this increase. Appliance trends in other end-uses such as water heating, cooking, refrigeration, and miscellaneous loads are captured in the base index.

The utilization variables (CoolUse, HeatUse, and BaseUse) are designed to capture energy consumption driven by the use of the appliance stock. For the residential sector, the primary factors that impact appliance use are weather conditions (as measured by heating and cooling degree days), electricity prices, household income and household size. The utilization variables are defined as:

COOLUSE = (PRICE^(-0.15)) * (INCOME_PER_HOUSEHOLD^0.2) * (HOUSEHOLD_SIZE^0.25) * COOLING_DEGREE_DAYS

HEATUSE = (PRICE^(-0.15)) * (INCOME_PER_HOUSEHOLD^0.2) * (HOUSEHOLD_SIZE^0.25) * HEATING_DEGREE_DAYS

BASEUSE = (PRICE^(-0.15)) * (INCOME_PER_HOUSEHOLD^0.1) * (HOUSEHOLD_SIZE^0.46)

In this functional form, the values shown in the specifications are, in effect, elasticities. The elasticities give the percent change in the utilization variables (CoolUse, HeatUse, and BaseUse) given a 1% change in the economic variables (Price, Income per Household, and Household Size). The elasticities are provided by Itron as part of the residential end-use model.

The forecast model is estimated by regressing monthly average residential usage on CoolUse, HeatUse, BaseUse, monthly seasonal variables for all months except February, March, April, May, September, October, and November, and binary variables for January 2007 and August 2012. The regression model effectively calibrates the end-use concepts to actual residential average use. Monthly seasonal variables are included to account for non-weather-related seasonal factors. The binary variables for January 2007 and August 2012 are included to account for unusual billing activity during this month. The model also includes a variable to account for the impact of the COVID-19 pandemic on residential sales. The forecast model results are adjusted to reflect the expected incremental impact of residential Demand-Side Management ("DSM") programs, sales related to residential EV charging, and Integrated Volt/VAr Optimization ("IVVO").

The same general approach is used to construct the commercial and industrial sales forecast model. For this model, sales can again be decomposed into heating, cooling and base use. The end-use variables Heating, Cooling and Base are structured in a manner similar to those used in the residential model and are defined as the product of a variable that reflects technology stock and efficiency ("Index") and a variable that captures stock utilization ("Use").

For the commercial and industrial sector, saturation and efficiency trends can be captured by the changes in annual energy intensities (kWh per square foot), which are then used in creating a Heating Index, Cooling Index, and Base Index. Increasing saturation levels drive an index higher, while improvements in stock efficiency or decreasing saturation levels lower the value of the index.

Stock utilization is a function of electricity prices, business activity (as measured by Gross Metropolitan Product for the metropolitan areas in the Public Service Company's service territory), heating degree days, and cooling degree days. The utilization variables are specified as:

COOLUSE = (PRICE^(-0.15)) * (Com. Output Index^0.25) * COOLING_DEGREE_DAYS

HEATUSE = (PRICE^(-0.15)) * (Com. Output Index^0.25) * HEATING_DEGREE_DAYS

BASEUSE = (PRICE^(-0.15)) * (Com. Output Index^0.25)

The forecast model is then estimated by regressing monthly commercial and industrial sales on Cooling, Heating, Base, monthly billing cycle days, commercial customer counts, and a monthly seasonal variable for February, April, May, and November. In addition, there are binary variables for April 2020, May 2020, and June 2020. The regression model effectively calibrates the end-use concepts to actual commercial and industrial sales. The monthly seasonal variables for each month are included to account for non-weather-related seasonal factors. The model results are adjusted to reflect the expected incremental impact of commercial and industrial DSM programs, sales related to commercial and industrial EV charging, and IVVO.

Public authority sales are forecasted based on recent trends and assumptions regarding light rail extensions.

Street light sales are forecasted using a regression model that is based on the forecast of the number minutes without sunlight, monthly seasonal variables for all months except January, February, and December, and binary variables for January 2013, February 2013, February 2016, November 2019, December 2019, January 2020, and February 2020. The monthly seasonal variables account for the differing number of hours per day that streetlights are on. The binary variables for January 2013, February 2013, February 2016, November 2019, December 2019, January 2020, and February 2020 account for the unusual billing activity observed during these months.

The interdepartmental sales forecast is developed as part of the commercial and industrial forecast.

The sales forecasts are then adjusted for losses to develop the energy forecast.

Figure 2.2-5 and Table 2.2-8 show the impact of EV adoption on retail energy. Retail energy, without adoption of additional EVs, grows 4,000 GWh, or about 13% through 2049. EVs account for 75% (12,000 GWh) of the total forecasted retail energy growth through 2049.

Figure 2.2-5 Retail Energy Forecasts

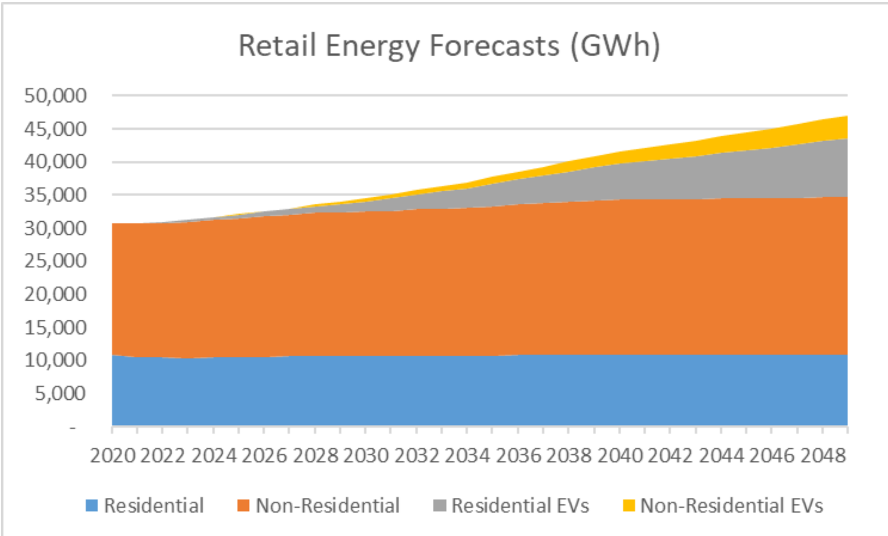


Table 2.2-8 Retail Energy Growth with and Without EVs

	Energy x/EVs (GWh)			EV Energy (GWh)			Total Retail	Change vs 2020 (GWh)		
	Residential	Non-Residential	Total	Residential	Non-Residential	Total	(GWh)	Non-EV	EV	Total
2020	10,843	19,946	30,788	19	2	22	30,810			
2021	10,451	20,209	30,660	60	7	67	30,727	(129)	46	(83)
2022	10,442	20,372	30,814	122	15	137	30,950	25	115	140
2023	10,393	20,586	30,979	238	30	267	31,246	191	246	436
2024	10,444	20,813	31,258	387	51	438	31,696	469	416	885
2025	10,509	21,044	31,553	527	77	603	32,156	765	582	1,346
2026	10,596	21,252	31,848	661	108	769	32,618	1,060	748	1,808
2027	10,638	21,400	32,037	812	152	964	33,001	1,249	942	2,191
2028	10,700	21,630	32,329	1,003	211	1,214	33,544	1,541	1,193	2,734
2029	10,726	21,692	32,418	1,245	288	1,534	33,952	1,630	1,512	3,141
2030	10,723	21,804	32,527	1,551	386	1,937	34,464	1,738	1,915	3,654
2031	10,707	21,929	32,636	1,898	500	2,397	35,034	1,848	2,376	4,223
2032	10,722	22,138	32,860	2,255	623	2,879	35,739	2,072	2,857	4,928
2033	10,721	22,192	32,912	2,626	756	3,381	36,294	2,124	3,360	5,484
2034	10,733	22,302	33,035	3,008	894	3,902	36,937	2,247	3,880	6,127
2035	10,749	22,522	33,272	3,395	1,039	4,434	37,705	2,483	4,412	6,895
2036	10,791	22,836	33,627	3,785	1,188	4,973	38,599	2,838	4,951	7,789
2037	10,793	22,986	33,779	4,175	1,342	5,518	39,297	2,991	5,496	8,487
2038	10,811	23,201	34,011	4,568	1,502	6,069	40,081	3,223	6,048	9,270
2039	10,836	23,360	34,196	4,962	1,665	6,627	40,824	3,408	6,605	10,013
2040	10,861	23,502	34,363	5,360	1,842	7,202	41,564	3,574	7,180	10,754
2041	10,851	23,469	34,320	5,762	2,024	7,786	42,106	3,532	7,765	11,296
2042	10,854	23,502	34,356	6,153	2,205	8,359	42,715	3,568	8,337	11,905
2043	10,861	23,551	34,412	6,504	2,382	8,886	43,298	3,624	8,865	12,488
2044	10,881	23,692	34,573	6,839	2,557	9,397	43,969	3,784	9,375	13,159
2045	10,862	23,660	34,522	7,208	2,736	9,944	44,466	3,733	9,923	13,656
2046	10,861	23,699	34,559	7,613	2,919	10,532	45,091	3,771	10,510	14,281
2047	10,868	23,754	34,621	8,037	3,104	11,141	45,762	3,833	11,120	14,952
2048	10,893	23,905	34,798	8,436	3,286	11,723	46,520	4,009	11,701	15,710
2049	10,879	23,880	34,759	8,771	3,461	12,232	46,991	3,971	12,211	16,181

Demand Forecast

Residential coincident peak demand is expected to increase in response to changes to residential energy requirements. For the residential demand regression model, residential energy requirements are defined as a 12-month moving average of monthly residential sales. The moving average calculation removes the monthly sales cyclical pattern. Efficiency improvements captured in the residential sales model are assumed to have the same impact on residential peak demand. Since peak demand does not necessarily grow at the same rate as the underlying sales, an end-use saturation term interacting with peak-day weather conditions and customer counts is also included in the model. This variable is defined as:

Max_Day_Cooling_Degree_Days * Customer Counts * CoolIndex

The cooling index is the same index used in the residential average use per customer model. With the cooling index variable, the sensitivity to max-day weather changes as residential cooling saturation and efficiency changes.

Also included in the residential peak model are max day heating degree days and binary variables to remove months with data anomalies (September 2014, April 2016, and September 2008). The model results are adjusted to reflect the expected incremental impact of residential DSM programs, the effect of residential EV charging on peak demand, and IVVO.

The commercial and industrial (nonresidential) coincident peak demand forecast is developed using a regression model similar to the residential peak model. Historical commercial and industrial coincident peaks are regressed against commercial and industrial energy requirements defined as the 12-month moving average of commercial and industrial sales. Also included in the model is a variable that allows peak demand to change at a different rate than sales. This variable, which interacts max day weather with commercial-industrial customers, reflects increasing cooling usage as customer counts increase. In addition, the model contains seasonal monthly variables (January, February, March, April, October, November, and December), binary variables to remove April 2006, April 2007, September 2008, April 2012, May 2015, and May 2017 from the regression, and a variable accounting for the impact of the COVID-19 pandemic on commercial and industrial peaks. The model results are adjusted to reflect the expected incremental impact of commercial and industrial DSM programs, the effect of commercial and industrial EV charging on peak demand, and IVVO.

Figure 2.2-6 and Table 2.2-9 show the impact of EV adoption on retail peak demand. Retail peaks, without adoption of additional EVs, grows about 1,470 MW, or about 24% through 2049. EVs account for 37% (865 MW) of the total retail peak growth through 2049.

Figure 2.2-6 Retail Peak Forecasts

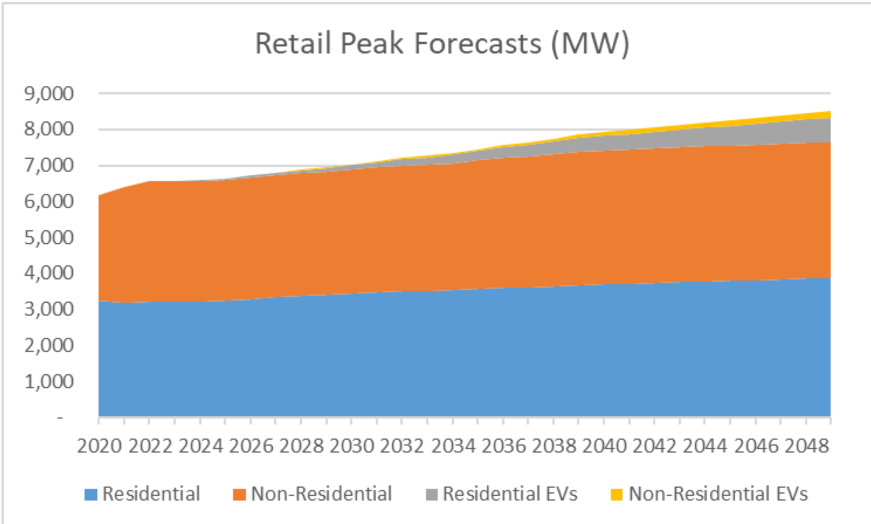


Table 2.2-9 Retail Peak Growth with and Without EVs

	Peak x/EVs (MW)			EV Peak Impact (MW)			Total Retail	Change vs 2020 (MW)		
	Residential	Non-Residential	Total	Residential	Non-Residential	Total	(MW)	Non-EV	EV	Total
2020	3,263	2,910	6,173	3	0	3	6,176			
2021	3,186	3,218	6,404	9	1	10	6,414	231	6	238
2022	3,201	3,350	6,551	10	1	11	6,562	378	8	386
2023	3,207	3,351	6,558	19	2	21	6,579	385	18	403
2024	3,223	3,342	6,565	30	4	34	6,599	392	31	423
2025	3,242	3,355	6,596	41	5	46	6,643	423	43	467
2026	3,286	3,380	6,666	51	7	59	6,725	494	55	549
2027	3,333	3,400	6,733	63	10	73	6,806	560	70	630
2028	3,373	3,417	6,790	78	13	91	6,882	617	88	705
2029	3,396	3,436	6,832	97	18	115	6,947	659	111	770
2030	3,436	3,455	6,891	121	24	144	7,035	718	141	859
2031	3,477	3,473	6,950	147	30	177	7,128	777	174	952
2032	3,511	3,489	7,000	175	37	212	7,212	827	209	1,036
2033	3,520	3,507	7,027	203	45	248	7,275	854	245	1,099
2034	3,543	3,524	7,067	233	53	286	7,353	895	282	1,177
2035	3,572	3,562	7,134	263	61	324	7,457	961	320	1,281
2036	3,602	3,600	7,202	293	69	362	7,564	1,029	359	1,388
2037	3,613	3,635	7,248	323	78	401	7,649	1,075	398	1,473
2038	3,637	3,671	7,308	353	87	440	7,748	1,135	437	1,572
2039	3,667	3,706	7,373	383	96	479	7,852	1,200	476	1,676
2040	3,697	3,722	7,419	414	106	519	7,939	1,246	516	1,763
2041	3,706	3,727	7,433	445	115	560	7,993	1,260	557	1,817
2042	3,728	3,731	7,460	475	125	600	8,060	1,287	597	1,883
2043	3,756	3,737	7,493	502	134	636	8,129	1,320	633	1,953
2044	3,783	3,740	7,523	528	144	671	8,195	1,350	668	2,019
2045	3,789	3,746	7,535	556	153	709	8,245	1,362	706	2,068
2046	3,810	3,752	7,562	587	163	750	8,313	1,389	747	2,137
2047	3,837	3,759	7,596	620	173	793	8,389	1,423	790	2,213
2048	3,864	3,764	7,628	651	183	834	8,461	1,455	830	2,285
2049	3,870	3,770	7,640	676	192	868	8,509	1,467	865	2,332

Roadmap Scenario

Public Service's Roadmap energy and peak scenario is based on the faster adoption of EVs and electrification of homes, as discussed earlier. As seen in Table 2.2-2, the resulting Roadmap energy forecast grows 2.0% annually through 2049, an increase of about 25,900 when compared to 2020. Energy growth is expected to average 1.2% through the RAP.

Public Service's Roadmap native load peak demand forecast grows from 7,002 MW in 2020 to 9,882 MW in 2049, an average annual growth rate of 1.2%. Short-term annual growth is expected to be 0.6% through 2030. The peak demand is expected to move from the summer to winter season in 2041, as the additional beneficial electrification leads to increased electric heating load and water heating load.

Table 2.2-10 on the following page shows the energy and peak impacts of the additional EV adoption and electrification of homes, as compared to the Base Case.

Table 2.2-10 Peak Impacts of Beneficial Electrification and EVs in Roadmap Scenario

	Peak Demand (MW)				Energy Forecast (GWh)			
	Base	BE	EV	**Roadmap**	Base	BE	EV	**Roadmap**
2020	7,002	-	-	**7,002**	34,319	-	-	**34,319**
2021	6,856	5	14	**6,875**	33,010	68	110	**33,188**
2022	6,973	10	19	**7,002**	32,929	146	277	**33,352**
2023	6,951	16	29	**6,996**	33,151	235	433	**33,819**
2024	6,978	24	41	**7,042**	33,766	335	600	**34,702**
2025	7,031	32	57	**7,120**	34,170	450	832	**35,452**
2026	6,906	41	76	**7,023**	33,737	578	1,105	**35,421**
2027	6,986	51	96	**7,133**	34,131	724	1,380	**36,234**
2028	7,063	62	112	**7,237**	34,685	887	1,610	**37,181**
2029	7,130	75	123	**7,328**	35,104	1,069	1,778	**37,951**
2030	7,219	90	133	**7,441**	35,627	1,274	1,925	**38,826**
2031	7,306	111	141	**7,558**	36,178	1,644	2,062	**39,883**
2032	7,413	134	150	**7,697**	36,895	2,055	2,212	**41,162**
2033	7,478	161	159	**7,798**	37,462	2,512	2,376	**42,351**
2034	7,558	190	169	**7,917**	38,118	3,020	2,557	**43,695**
2035	7,665	223	179	**8,067**	38,899	3,584	2,756	**45,238**
2036	7,774	260	190	**8,224**	39,805	4,209	2,958	**46,972**
2037	7,862	301	200	**8,363**	40,516	4,903	3,156	**48,575**
2038	7,963	347	210	**8,519**	41,313	5,673	3,348	**50,333**
2039	8,069	398	219	**8,686**	42,069	6,527	3,525	**52,122**
2040	8,159	455	226	**8,840**	42,823	7,474	3,679	**53,976**
2041	5,659	2,949	354	**8,962**	43,379	7,711	3,767	**54,858**
2042	5,585	3,067	353	**9,005**	44,002	7,956	3,821	**55,778**
2043	5,422	3,079	353	**8,855**	43,298	8,208	3,875	**55,382**
2044	5,529	3,315	351	**9,195**	43,969	8,469	3,908	**56,346**
2045	5,639	3,446	334	**9,419**	44,466	8,738	3,867	**57,071**
2046	5,815	3,581	306	**9,702**	45,091	9,015	3,732	**57,839**
2047	5,794	3,722	279	**9,795**	45,762	9,301	3,560	**58,623**
2048	5,682	3,731	277	**9,690**	46,520	9,596	3,400	**59,516**
2049	5,751	3,876	255	**9,882**	46,991	9,901	3,288	**60,181**

Note: System becomes winter peaking in 2041

Low Growth Scenario

Public Service's Low scenario energy forecast assumes that the energy not attributed to EV adoption grows at about half the rate as in the Base forecast. The pace of EV adoption remains the same as in the Base Case. The resulting Low native energy forecast grows 0.9% annually through 2049, adding about 10,000 GWh during that period. Through the RAP, Low scenario energy remains flat to 2020 levels. Energy growth in the Low scenario is primarily driven by EV adoption, which is assumed to be the same as in the Base Case.

Public Service's Low summer native load peak demand forecast grows from 7,002 MW in 2020 to 7,822 MW in 2049, an average annual growth rate of 0.4%. The peak demand is only expected to advance 10 MW through the RAP in the Low scenario.

Table 2.2-11 shows the impact of the lower non-EV growth assumptions on the peak and energy forecasts.

Table 2.2-11 Peak and Energy Impact of Slower Growth

	Peak Demand (MW)			Energy Forecast (GWh)		
	Base	Slow Growth	**Low**	Base	Slow Growth	**Low**
2020	7,002	-	**7,002**	34,319	-	**34,319**
2021	6,856	(0)	**6,856**	33,010	(0)	**33,010**
2022	6,973	(0)	**6,973**	32,929	(185)	**32,745**
2023	6,951	(14)	**6,936**	33,151	(276)	**32,874**
2024	6,978	(33)	**6,944**	33,766	(425)	**33,341**
2025	7,031	(71)	**6,960**	34,170	(617)	**33,554**
2026	6,906	(107)	**6,799**	33,737	(772)	**32,965**
2027	6,986	(131)	**6,855**	34,131	(875)	**33,255**
2028	7,063	(168)	**6,896**	34,685	(1,033)	**33,652**
2029	7,130	(185)	**6,945**	35,104	(1,088)	**34,015**
2030	7,219	(207)	**7,012**	35,627	(1,157)	**34,470**
2031	7,306	(230)	**7,076**	36,178	(1,228)	**34,950**
2032	7,413	(265)	**7,148**	36,895	(1,359)	**35,535**
2033	7,478	(282)	**7,196**	37,462	(1,402)	**36,060**
2034	7,558	(308)	**7,251**	38,118	(1,483)	**36,635**
2035	7,665	(346)	**7,319**	38,899	(1,623)	**37,276**
2036	7,774	(396)	**7,379**	39,805	(1,826)	**37,980**
2037	7,862	(425)	**7,437**	40,516	(1,923)	**38,592**
2038	7,963	(463)	**7,500**	41,313	(2,064)	**39,249**
2039	8,069	(497)	**7,573**	42,069	(2,180)	**39,889**
2040	8,159	(528)	**7,631**	42,823	(2,286)	**40,537**
2041	8,216	(537)	**7,679**	43,379	(2,296)	**41,084**
2042	8,285	(555)	**7,731**	44,002	(2,334)	**41,668**
2043	8,129	(574)	**7,555**	43,298	(2,382)	**40,917**
2044	8,195	(601)	**7,593**	43,969	(2,484)	**41,485**
2045	8,245	(609)	**7,636**	44,466	(2,490)	**41,976**
2046	8,313	(627)	**7,686**	45,091	(2,530)	**42,561**
2047	8,389	(648)	**7,741**	45,762	(2,583)	**43,180**
2048	8,461	(678)	**7,783**	46,520	(2,696)	**43,824**
2049	8,509	(687)	**7,822**	46,991	(2,706)	**44,286**

<u>System Load Shapes</u>

Figures 2.2-7 through 2.2-9 show the hourly system loads for the Base Case summer and winter peak days in 2025, 2030, and 2040. Figures 2.2-10 through 2.2-15 show the hourly system loads for those same days for the Roadmap and Low scenarios.

Figure 2.2-7 2025 Peak Day Load Shape – Base Case

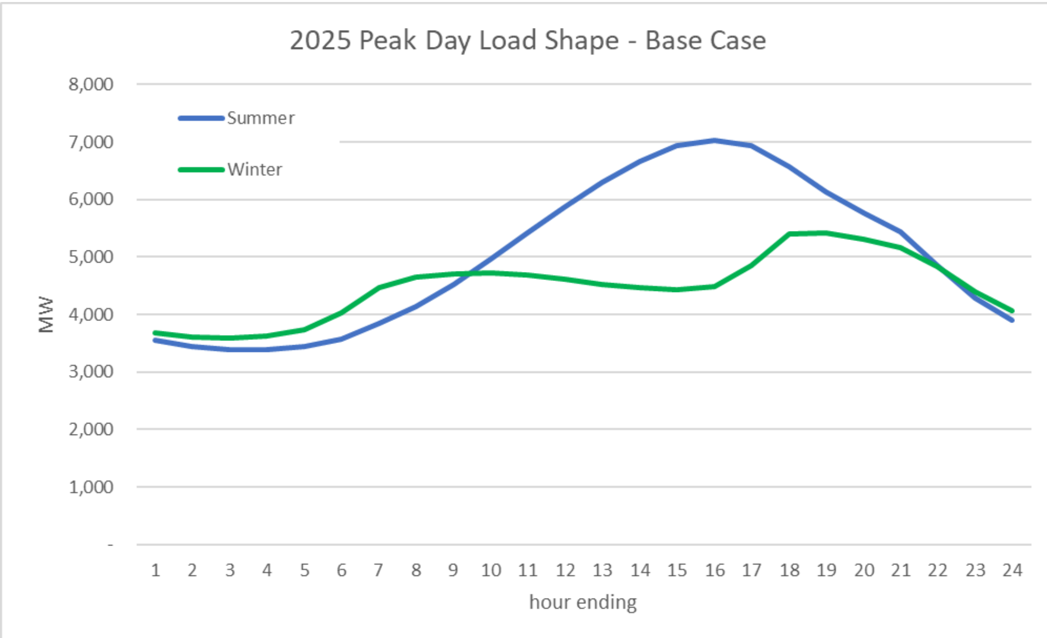


Figure 2.2-8 2030 Peak Day Load Shape – Base Case

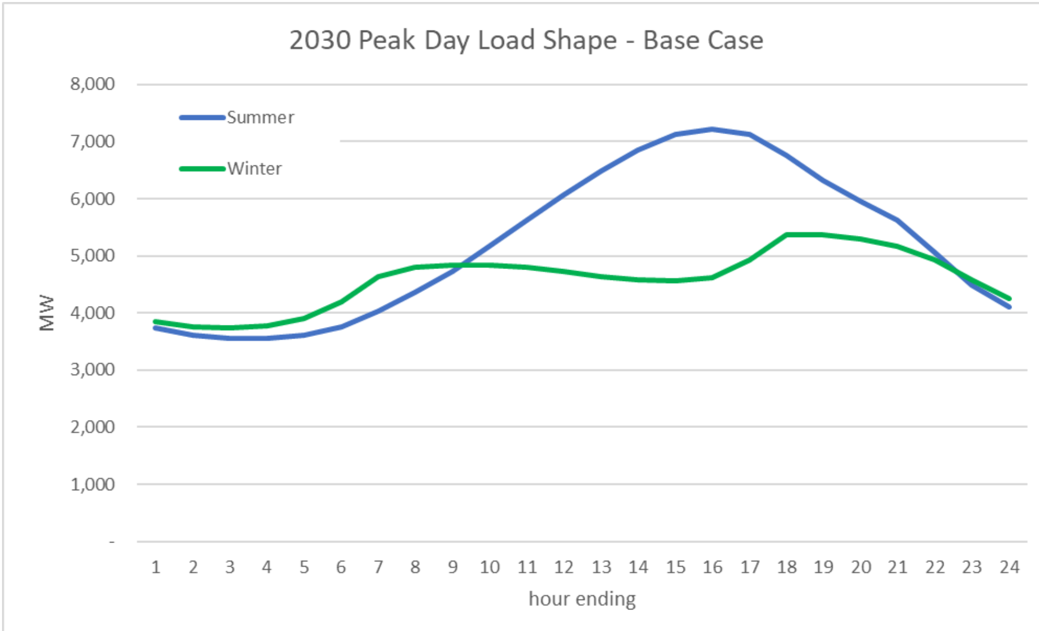


Figure 2.2-9 2040 Peak Day Load Shape – Base Case

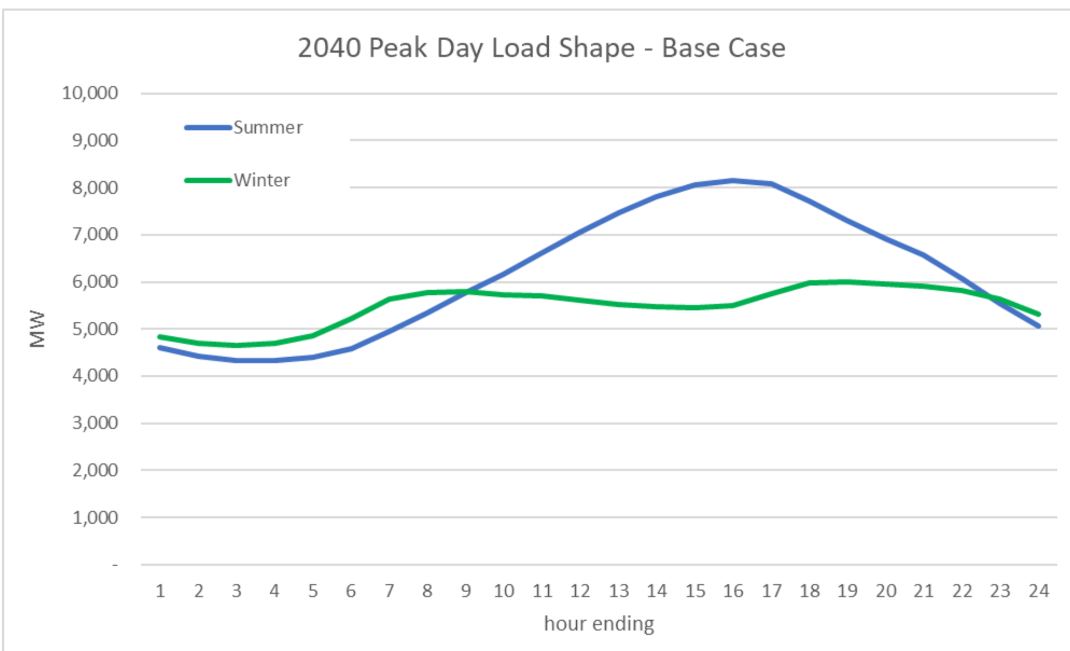


Figure 2.2-10 2025 Load Shapes – Roadmap Scenario

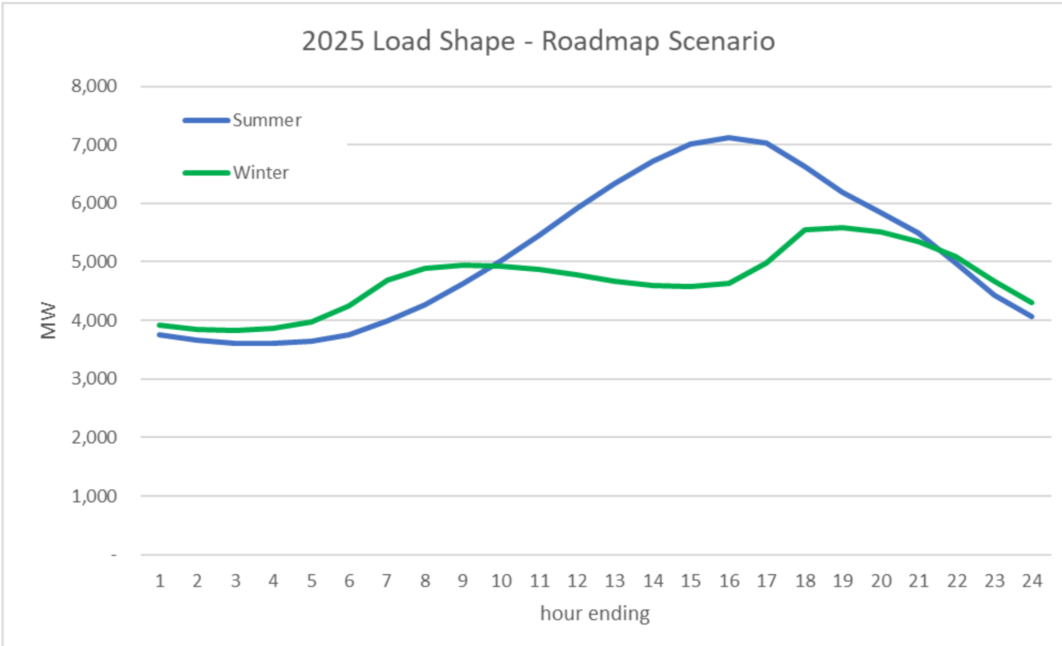


Figure 2.2-11 2030 Load Shapes – Roadmap Scenario

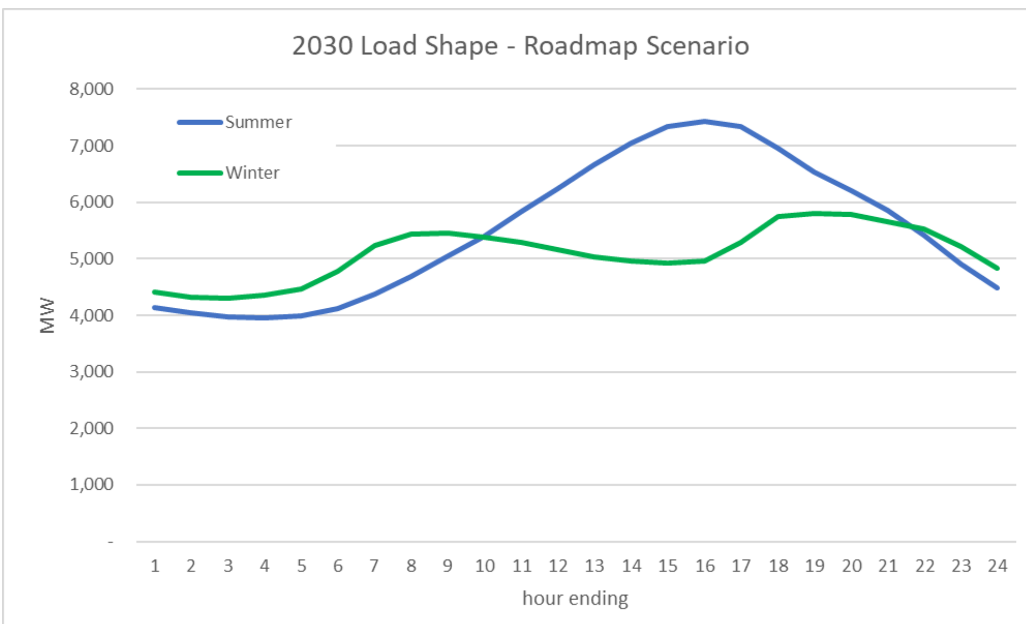


Figure 2.2-12 2040 Load Shapes – Roadmap Scenario

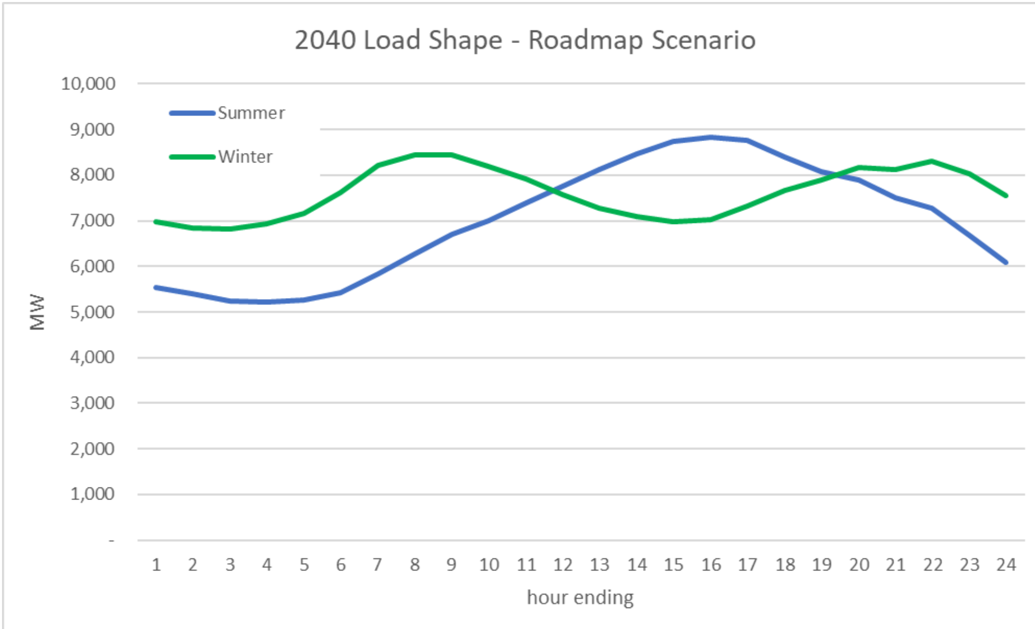


Figure 2.2-13 2025 Load Shapes – Low Scenario

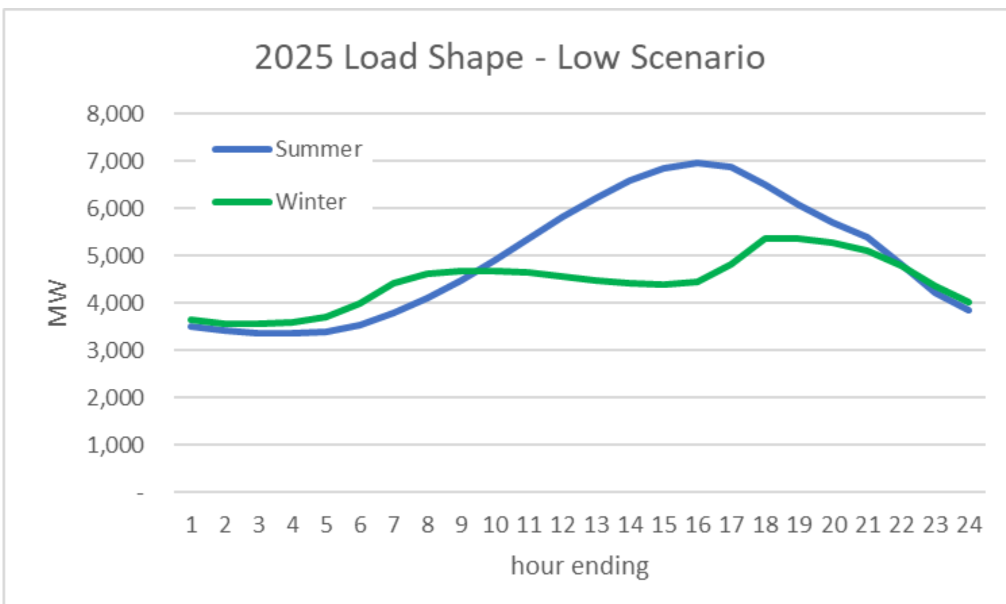


Figure 2.2-14 2030 Load Shapes – Low Scenario

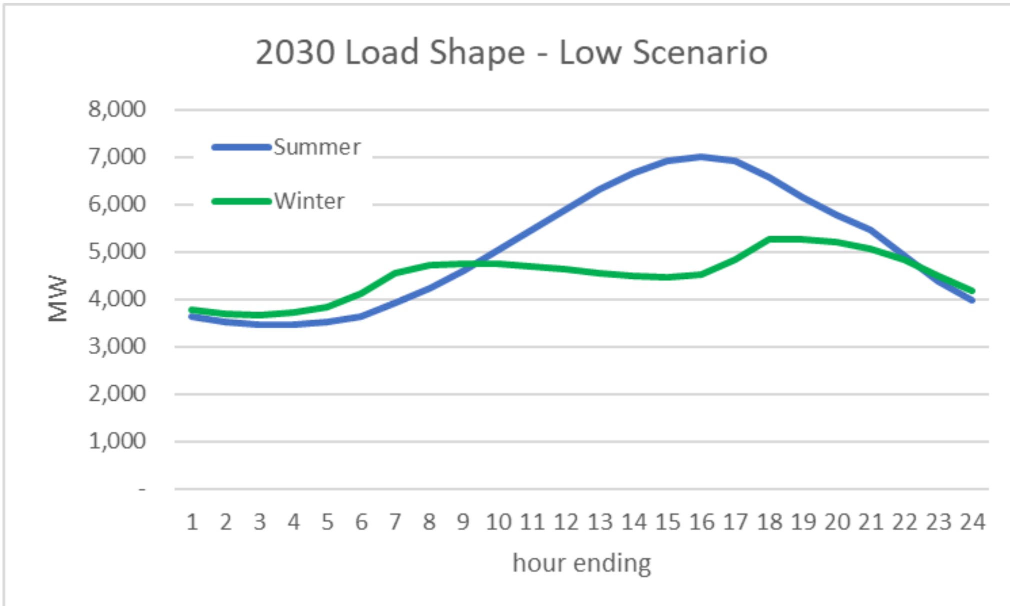
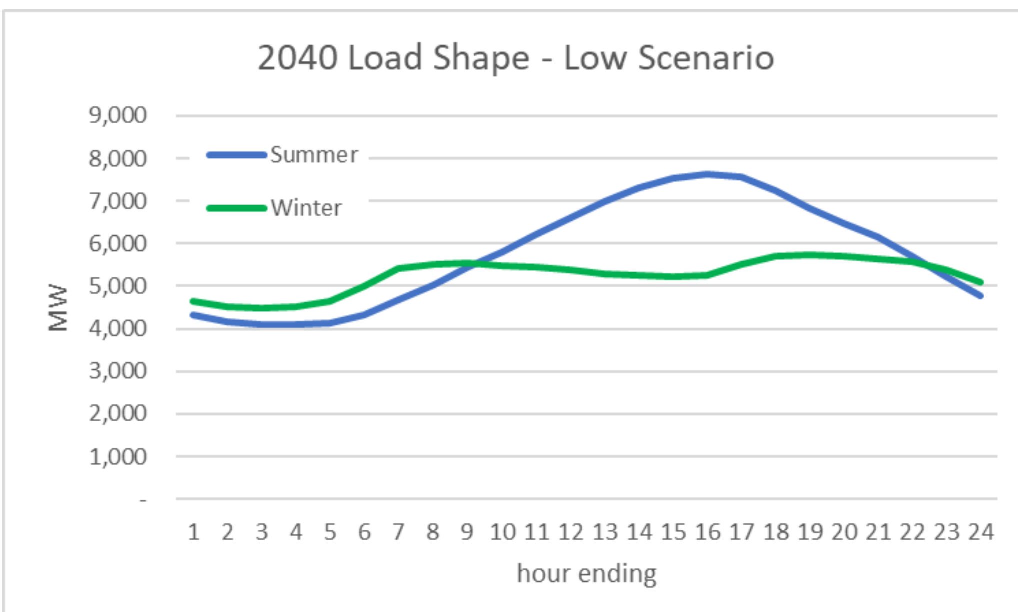


Figure 2.2-15 2040 Load Shapes – Low Scenario



In the Base Case, there is little variation in the benchmark years between the summer load shapes, and variation in the winter load shape only becomes noticeable in the 2040 time period. Similar results for the summer load shape are seen in the Roadmap scenario; however, the winter load undergoes a significant change in shape over time, resulting in a flattening of the load curve as additional beneficial electrification and faster EV adoption occur. As an example of the impact of the increase in beneficial electrification and EV adoption on the Roadmap scenario load shapes, Figures 2.2-16 and 2.2-17 below layer the Roadmap assumptions for additional (above the Base Case) EVs and beneficial electrification onto the Base Case load shape for the 2040 summer and winter peak days. These illustrations show the clear and significant impact that beneficial electrification load growth specifically has on the winter load shape. Beneficial electrification growth causes a dual peak due to the coincidence of early morning and evening space heating, while EV load growth has a similar peak impact in both the winter and summer periods.

Figure 2.2-16 Impact of EVs and Beneficial Electrification (BE) on Roadmap Scenario – Summer 2040

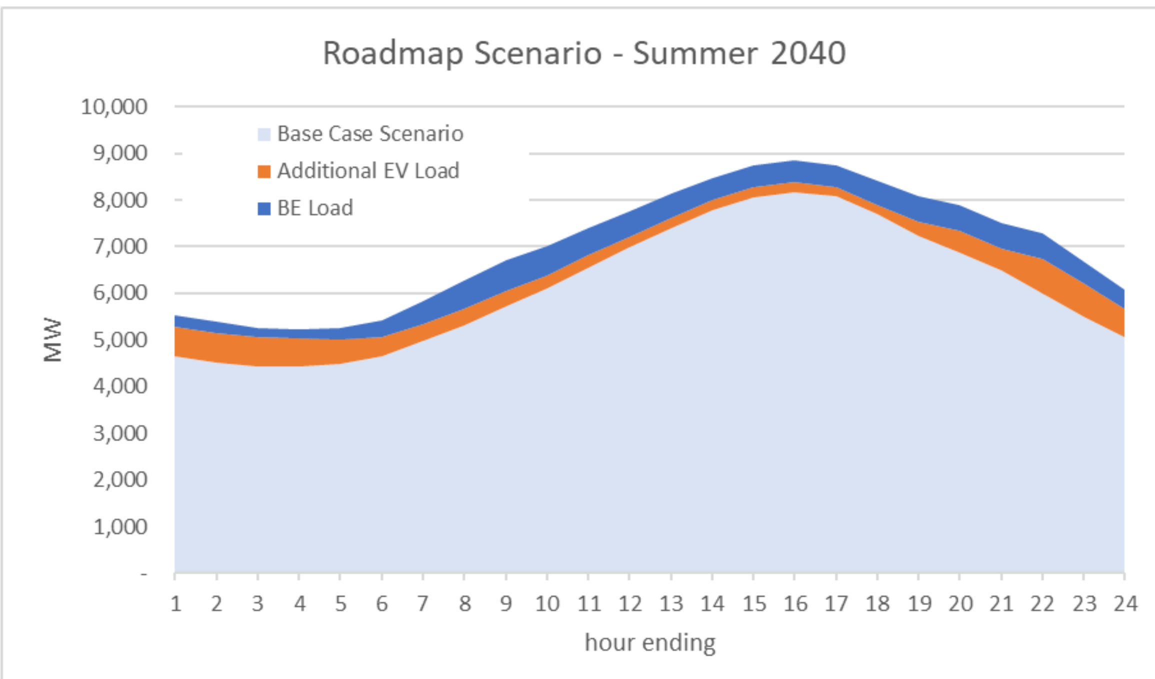
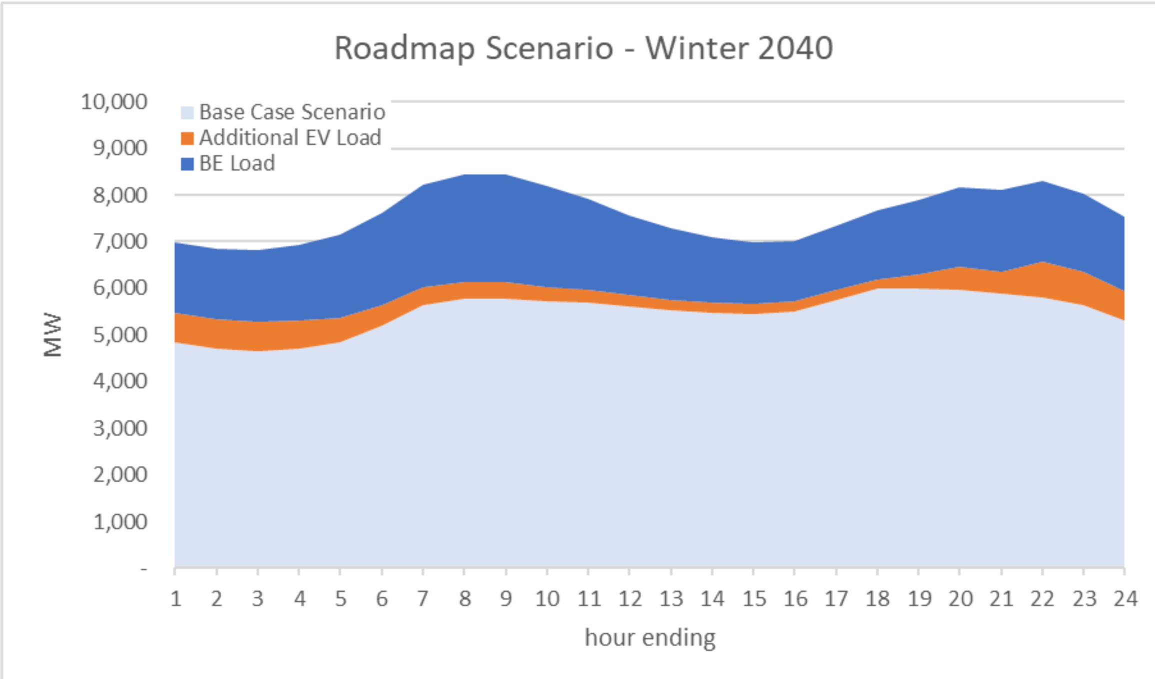


Figure 2.2-17 Impact of EVs and Beneficial Electrification (BE) on Roadmap Scenario – Winter 2040



Comparison to 2016 ERP

Table 2.2-12 and Figures 2.2-18 and 2.2-19 show a comparison of the 2021 and 2016 ERP forecasts.

Table 2.2-12 Base Case Forecast Comparison with 2016 ERP

	Peak Demand (MW)		Annual Energy (GWh)	
	2016 ERP	2021 ERP	2016 ERP	2021 ERP
2020	6,970	7,002	35,889	34,319
2021	7,102	6,856	36,754	33,010
2022	7,161	6,973	37,116	32,929
2023	7,225	6,951	37,484	33,151
2024	7,299	6,978	37,878	33,766
2025	7,352	7,031	38,190	34,170
2026	7,413	6,906	38,537	33,737
2027	7,479	6,986	38,915	34,131
2028	7,557	7,063	39,312	34,685
2029	7,615	7,130	39,742	35,104
2030	7,680	7,219	40,130	35,627
2031	7,738	7,306	40,496	36,178
2032	7,802	7,413	40,859	36,895
2033	7,850	7,478	41,214	37,462
2034	7,902	7,558	41,579	38,118
2035	7,962	7,665	41,957	38,899
2036	8,045	7,774	42,340	39,805
2037	8,098	7,862	42,677	40,516
2038	8,163	7,963	43,016	41,313
2039	8,225	8,069	43,367	42,069
2040	8,299	8,159	43,717	42,823
2041	8,352	8,216	44,053	43,379
2042	8,416	8,285	44,400	44,002
2043	8,481	8,129	44,743	43,298
2044	8,554	8,195	45,126	43,969
2045	8,613	8,245	45,528	44,466
2046	8,670	8,313	45,873	45,091
2047	8,717	8,389	46,218	45,762
2048	8,761	8,461	46,667	46,520
2049	8,802	8,509	47,031	46,991

Figure 2.2-18 Peak Forecast Comparison with 2016 ERP

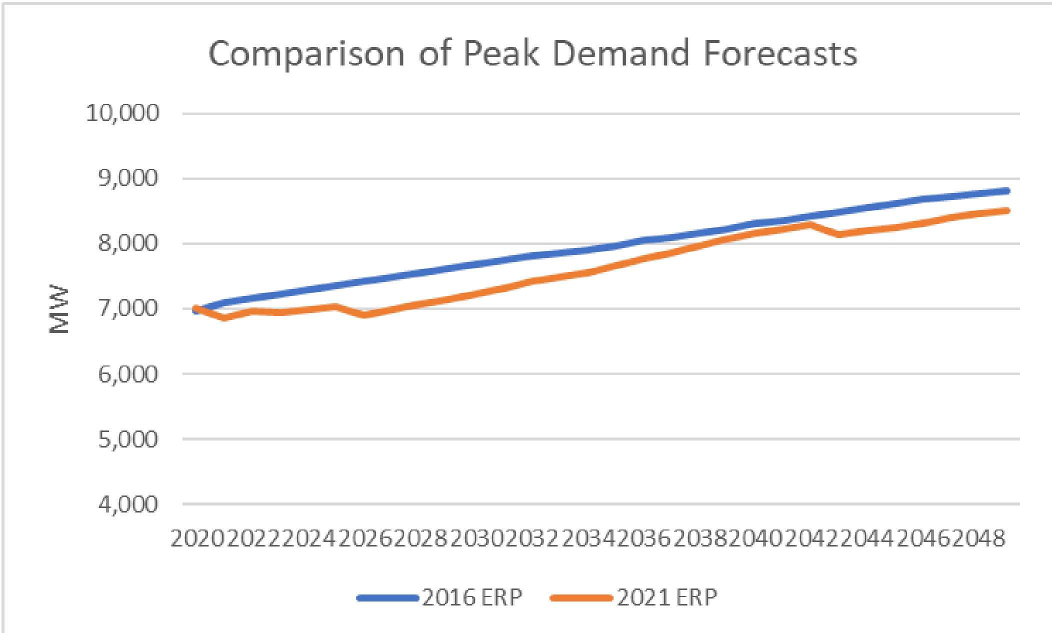
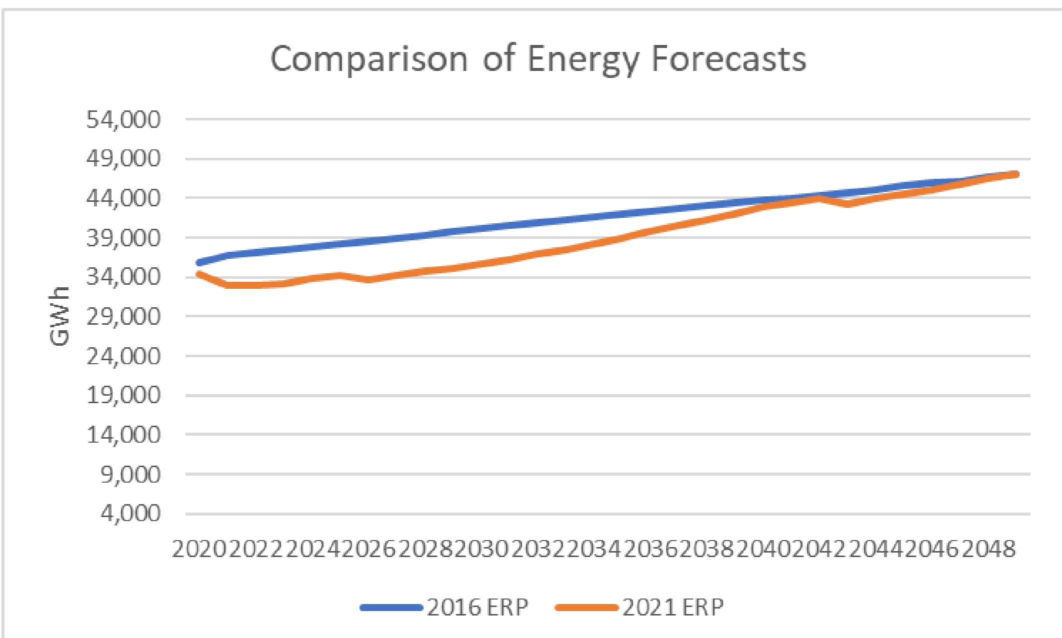


Figure 2.2-19 Energy Forecast Comparison with 2016 ERP



Additional Energy and Demand Forecast Information

Tables 2.2-13 through 2.2-17 present additional information associated with the energy and demand forecasts.

Table 2.2-13 Base Case, Low, and High (Roadmap) Coincident Summer and Winter Peak Demand

	Coincident Summer Peak Demand (MW)			Coincident Winter Peak Demand (MW)		
	Base	Low	Roadmap	Base	Low	Roadmap
2020	7,002	7,002	7,002	5,056	5,056	5,056
2021	6,856	6,856	6,875	5,206	5,206	5,255
2022	6,973	6,973	7,002	5,349	5,349	5,404
2023	6,951	6,936	6,996	5,352	5,349	5,434
2024	6,978	6,944	7,042	5,358	5,344	5,484
2025	7,031	6,960	7,120	5,412	5,373	5,581
2026	6,906	6,799	7,023	5,161	5,099	5,359
2027	6,986	6,855	7,133	5,210	5,134	5,458
2028	7,063	6,896	7,237	5,252	5,155	5,542
2029	7,130	6,945	7,328	5,317	5,215	5,717
2030	7,219	7,012	7,441	5,375	5,267	5,805
2031	7,306	7,076	7,558	5,428	5,312	5,937
2032	7,413	7,148	7,697	5,438	5,304	6,016
2033	7,478	7,196	7,798	5,503	5,363	6,246
2034	7,558	7,251	7,917	5,560	5,407	6,432
2035	7,665	7,319	8,067	5,639	5,467	6,882
2036	7,774	7,379	8,224	5,710	5,509	6,989
2037	7,862	7,437	8,363	5,795	5,579	7,298
2038	7,963	7,500	8,519	5,872	5,636	7,766
2039	8,069	7,573	8,686	5,945	5,693	8,202
2040	8,159	7,631	8,840	5,990	5,725	8,799
2041	8,216	7,679	8,909	6,041	5,776	8,962
2042	8,285	7,731	8,989	6,083	5,812	9,005
2043	8,129	7,555	8,843	5,810	5,531	8,855
2044	8,195	7,593	8,919	5,835	5,545	9,195
2045	8,245	7,636	8,973	5,883	5,592	9,419
2046	8,313	7,686	9,039	5,925	5,631	9,702
2047	8,389	7,741	9,111	5,969	5,667	9,795
2048	8,461	7,783	9,181	5,999	5,680	9,690
2049	8,509	7,822	9,229	6,041	5,720	9,882

Table 2.2-14 Base Case: Energy/Coincident Summer Demand/Winter Peak Demand by Major Customer Class

	Energy (GWh)					Coincident Summer Peak Demand (MW)					Coincident Winter Peak Demand (MW)				
Year	Residential	Small & Large Commercial & Industrial	Other	Resale	Total	Residential	Small & Large Commercial & Industrial	Other	Resale	Total	Residential	Small & Large Commercial & Industrial	Other	Resale	Total
2020	10,862	19,695	253	3,509	34,319	3,266	2,895	15	826	7,002	2,168	2,233	81	575	5,056
2021	10,511	19,918	298	2,283	33,010	3,194	3,198	21	443	6,856	2,167	2,348	96	594	5,206
2022	10,564	20,081	305	1,979	32,929	3,211	3,329	22	411	6,973	2,161	2,486	98	604	5,349
2023	10,631	20,304	311	1,905	33,151	3,226	3,330	23	372	6,951	2,161	2,478	100	613	5,352
2024	10,831	20,552	312	2,071	33,766	3,253	3,322	23	379	6,978	2,168	2,468	100	621	5,358
2025	11,036	20,807	313	2,014	34,170	3,283	3,337	23	388	7,031	2,199	2,487	100	626	5,412
2026	11,258	21,047	314	1,120	33,737	3,338	3,364	23	180	6,906	2,229	2,511	101	321	5,161
2027	11,450	21,237	314	1,129	34,131	3,396	3,387	23	181	6,986	2,255	2,533	101	321	5,210
2028	11,703	21,527	314	1,141	34,685	3,451	3,407	23	182	7,063	2,277	2,552	101	323	5,252
2029	11,971	21,668	313	1,152	35,104	3,493	3,431	23	183	7,130	2,315	2,578	101	324	5,317
2030	12,274	21,877	313	1,163	35,627	3,557	3,455	23	184	7,219	2,347	2,602	101	324	5,375
2031	12,605	22,116	313	1,144	36,178	3,625	3,480	23	178	7,306	2,377	2,626	101	323	5,428
2032	12,977	22,449	313	1,156	36,895	3,686	3,503	23	201	7,413	2,400	2,648	102	289	5,438
2033	13,347	22,634	313	1,168	37,462	3,723	3,529	23	203	7,478	2,435	2,677	102	290	5,503
2034	13,741	22,884	313	1,181	38,118	3,776	3,554	23	205	7,558	2,463	2,703	102	292	5,560
2035	14,145	23,248	313	1,193	38,899	3,835	3,600	23	208	7,665	2,492	2,752	102	293	5,639
2036	14,576	23,711	313	1,206	39,805	3,895	3,646	23	210	7,774	2,515	2,798	102	295	5,710
2037	14,969	24,015	313	1,219	40,516	3,936	3,690	23	212	7,862	2,550	2,846	102	297	5,795
2038	15,379	24,389	313	1,232	41,313	3,990	3,735	23	215	7,963	2,579	2,891	103	298	5,872
2039	15,798	24,713	313	1,245	42,069	4,050	3,779	23	217	8,069	2,609	2,933	103	300	5,945
2040	16,221	25,030	313	1,259	42,823	4,111	3,805	23	220	8,159	2,631	2,954	103	302	5,990
2041	16,613	25,181	313	1,273	43,379	4,151	3,819	23	223	8,216	2,664	2,970	103	304	6,041
2042	17,008	25,394	313	1,287	44,002	4,203	3,833	23	226	8,285	2,692	2,982	103	306	6,083
2043	17,365	25,620	313	0	43,298	4,257	3,849	23	0	8,129	2,713	2,993	103	0	5,810
2044	17,720	25,936	313	0	43,969	4,311	3,861	23	0	8,195	2,731	3,000	104	0	5,835
2045	18,070	26,083	313	0	44,466	4,346	3,876	23	0	8,245	2,763	3,016	104	0	5,883
2046	18,474	26,305	313	0	45,091	4,398	3,892	23	0	8,313	2,793	3,028	104	0	5,925
2047	18,905	26,545	313	0	45,762	4,457	3,909	23	0	8,389	2,824	3,041	104	0	5,969
2048	19,329	26,878	313	0	46,520	4,515	3,924	23	0	8,461	2,845	3,049	104	0	5,999
2049	19,650	27,028	313	0	46,991	4,546	3,940	23	0	8,509	2,872	3,064	104	0	6,041

Table 2.2-15 Base Case: Intra-Utility Energy and Capacity Use (at the Time of Coincident Summer and Winter Peak Demand)

	Energy (GWh)		Coincident Summer Demand (MW)		Coincident Winter Demand (MW)	
	Interdepartment	Company Use	Interdepartment	Company Use	Interdepartment	Company Use
2020	3	22	0	3	3	3
2021	3	22	1	3	3	3
2022	3	22	1	3	3	3
2023	3	22	1	3	3	3
2024	3	22	1	3	3	3
2025	3	22	1	3	3	3
2026	3	22	1	3	3	3
2027	3	22	1	3	3	3
2028	3	22	1	3	3	3
2029	3	22	1	3	3	3
2030	3	22	1	3	3	3
2031	3	22	1	3	3	3
2032	3	22	1	3	3	3
2033	3	22	1	3	3	3
2034	3	22	1	3	3	3
2035	3	22	1	3	3	3
2036	3	22	1	3	3	3
2037	3	22	1	3	3	3
2038	3	22	1	3	3	3
2039	3	22	1	3	3	3
2040	3	22	1	3	3	3
2041	3	22	1	3	3	3
2042	3	22	1	3	3	3
2043	3	22	1	3	3	3
2044	3	22	1	3	3	3
2045	3	22	1	3	3	3
2046	3	22	1	3	3	3
2047	3	22	1	3	3	3
2048	3	22	1	3	3	3
2049	3	22	1	3	3	3

Table 2.2-16 Base Case: Losses by Major Customer Class

	Energy Losses (GWh)				Coincident Summer Demand Losses (MW)				Coincident Winter Demand Losses(MW)			
	Residential	Commercial & Industrial	Other	FERC	Residential	Commercial & Industrial	Other	FERC	Residential	Commercial & Industrial	Other	FERC
2020	693	1,106	16	60	244	195	1	18	167	148	6	13
2021	671	1,059	19	39	237	212	1	10	167	155	7	13
2022	674	1,065	19	34	237	220	1	9	166	165	7	13
2023	678	1,077	20	32	237	220	1	8	166	164	7	13
2024	691	1,091	20	35	238	219	1	8	167	163	7	14
2025	704	1,106	20	34	239	220	1	9	169	165	7	14
2026	718	1,120	20	19	243	221	1	4	171	166	7	7
2027	731	1,132	20	19	246	223	1	4	173	168	7	7
2028	747	1,148	20	19	249	224	1	4	175	169	7	7
2029	764	1,157	20	20	250	225	1	4	178	171	7	7
2030	783	1,169	20	20	253	226	1	4	181	172	7	7
2031	804	1,183	20	19	256	228	1	4	183	174	7	7
2032	828	1,203	20	20	259	229	1	4	185	175	7	6
2033	852	1,214	20	20	261	230	1	4	187	177	7	6
2034	877	1,229	20	20	263	231	1	5	189	179	7	6
2035	902	1,250	20	20	265	234	1	5	192	182	7	6
2036	930	1,278	20	21	268	237	1	5	193	185	7	6
2037	955	1,296	20	21	269	239	1	5	196	188	7	7
2038	981	1,318	20	21	271	242	1	5	198	191	7	7
2039	1,008	1,337	20	21	274	245	1	5	201	194	7	7
2040	1,035	1,356	20	21	276	246	1	5	202	195	7	7
2041	1,060	1,365	20	22	277	246	1	5	205	197	7	7
2042	1,085	1,378	20	22	279	247	1	5	207	197	7	7
2043	1,108	1,392	20	0	282	247	1	0	209	198	7	0
2044	1,131	1,410	20	0	284	248	1	0	210	199	7	0
2045	1,153	1,419	20	0	285	248	1	0	212	200	7	0
2046	1,179	1,433	20	0	287	249	1	0	215	200	7	0
2047	1,206	1,447	20	0	290	249	1	0	217	201	7	0
2048	1,233	1,467	20	0	293	250	1	0	219	202	7	0
2049	1,254	1,476	20	0	294	250	1	0	221	203	7	0

Note: System Loss estimates cannot be made for the transmission and distribution levels because the forecast was not developed at the transmission and distribution voltage level.

Table 2.2-17 Future DSM Energy and Peak Impacts Used in Modeling

	Energy Savings (GWh)	Coincident Summer Demand Savings (MW)	Coincident Winter Demand Savings (MW)
2020	503	96	89
2021	1,002	188	176
2022	1,502	275	258
2023	2,002	362	340
2024	2,408	449	422
2025	2,702	519	487
2026	3,002	572	537
2027	3,169	589	564
2028	3,345	611	594
2029	3,504	633	624
2030	3,672	655	653
2031	3,866	677	683
2032	4,071	705	717
2033	4,254	740	755
2034	4,449	774	792
2035	4,274	747	762
2036	4,111	719	732
2037	3,927	696	707
2038	3,753	674	682
2039	3,653	651	657
2040	3,663	640	645
2041	3,653	640	645
2042	3,653	640	645
2043	3,653	640	645
2044	3,663	640	645
2045	3,653	640	645
2046	3,653	640	645
2047	3,653	640	645
2048	3,663	640	645
2049	3,653	640	645

Forecast Accuracy

Public Service reviews its demand and energy forecasts for accuracy annually. Tables 2.2-18 through 2.2-25 on the following pages compare the actual energy and demand forecasts to the forecasted energy and system demands, as required by the Electric Resource Planning rules. The Adjusted Actual Demand column in the summer peak demand table (Table 2.2-20) accounts for the additional load served due to Comanche 3 being offline at the time of the peak. The forecasts assume Comanche 3 will be operational, so this adjustment allows for a more direct comparison to the forecasts. Figures 2.2-20 through 2.2-22 contain a graphical description of the forecasts.

Table 2.2-18 Native Energy Forecast Comparison (GWh)

	Actual Energy	2020 Forecast	2019 Forecast	2018 Forecast	2017 Forecast	2016 Forecast
2016	32,856					33,107
2017	32,929				34,622	33,258
2018	33,363			33,459	34,248	33,176
2019	33,282		33,739	33,988	34,638	33,503
2020	34,319	34,181	34,353	34,383	34,731	33,692

Table 2.2-19 Forecast Energy Less Actual Energy (GWh)

	Actual less Forecast					Percent Difference				
	2020 Forecast	2019 Forecast	2018 Forecast	2017 Forecast	2016 Forecast	2020 Forecast	2019 Forecast	2018 Forecast	2017 Forecast	2016 Forecast
2016					-251					-0.8%
2017				-1,693	-328				-5.1%	-1.0%
2018			-96	-885	187			-0.3%	-2.7%	0.6%
2019		-457	-706	-1,356	-222		-1.4%	-2.1%	-4.1%	-0.7%
2020	138	-34	-64	-412	627	0.4%	-0.1%	-0.2%	-1.2%	1.8%

Table 2.2-20 Coincident Summer Demand Forecast Comparison (MW)

	Adjusted Actual Demand	Actual Demand	2020 Forecast	2019 Forecast	2018 Forecast	2017 Forecast	2016 Forecast
2016	6,580	6,670					6,478
2017	6,767	6,767				6,586	6,565
2018	6,758	6,758			6,566	6,618	6,628
2019	6,743	6,992		6,795	6,638	6,658	6,682
2020	6,753	7,002	6,770	6,803	6,690	6,709	6,712

Table 2.2-21 Forecast Demand Less Actual Summer Native Peak Demand (MW)

	Actual less Forecast (MW)					Percent Difference				
	2020 Forecast	2019 Forecast	2018 Forecast	2017 Forecast	2016 Forecast	2020 Forecast	2019 Forecast	2018 Forecast	2017 Forecast	2016 Forecast
2016					192					2.9%
2017				182	203				2.7%	3.0%
2018			192	140	130			2.8%	2.1%	1.9%
2019		197	355	334	311		2.8%	5.1%	4.8%	4.4%
2020	232	199	312	293	290	3.3%	2.8%	4.5%	4.2%	4.1%

Table 2.2-22 Weather Normalized Coincident Summer Demand Forecast Comparison (MW)

	Weather Normal Demand	2020 Forecast	2019 Forecast	2018 Forecast	2017 Forecast	2016 Forecast
2016	6,730					6,478
2017	6,499				6,586	6,565
2018	6,933			6,566	6,618	6,628
2019	7,050		6,795	6,638	6,658	6,682
2020	7,107	6,770	6,803	6,690	6,709	6,712

Table 2.2-23 Forecast Demand Less Actual Weather Normalized Summer Demand (MW)

	Actual less Forecast (MW)					Percent Difference				
	2020 Forecast	2019 Forecast	2018 Forecast	2017 Forecast	2016 Forecast	2020 Forecast	2019 Forecast	2018 Forecast	2017 Forecast	2016 Forecast
2016					252					3.7%
2017				-86	-65				-1.3%	-1.0%
2018			367	316	306			5.3%	4.6%	4.4%
2019		255	413	392	369		3.6%	5.9%	5.6%	5.2%
2020	337	304	417	398	394	4.7%	4.3%	5.9%	5.6%	5.6%

Table 2.2-24 Coincident Winter Demand Forecast Comparison (MW)

	Actual Winter Demand	2019 Forecast	2018 Forecast	2017 Forecast	2016 Forecast	2015 Forecast
2015	5,141					5,252
2016	5,398				5,196	5,275
2017	5,381			5,354	5,258	5,339
2018	5,250		5,289	5,346	5,309	5,386
2019	5,069	5,304	5,330	5,390	5,345	5,420

Table 2.2-25 Forecast Demand Less Actual Winter Demand (MW)

	Actual less Forecast (MW)					Percent Difference				
	2019 Forecast	2018 Forecast	2017 Forecast	2016 Forecast	2015 Forecast	2019 Forecast	2018 Forecast	2017 Forecast	2016 Forecast	2015 Forecast
2015					-111					-2.2%
2016				202	122				3.7%	2.3%
2017			26	122	41			0.5%	2.3%	0.8%
2018		-40	-96	-60	-137		-0.8%	-1.8%	-1.1%	-2.6%
2019	-235	-261	-321	-276	-351	-4.6%	-5.1%	-6.3%	-5.4%	-6.9%

Figure 2.2-20 Forecast Comparison to Actual Native Energy

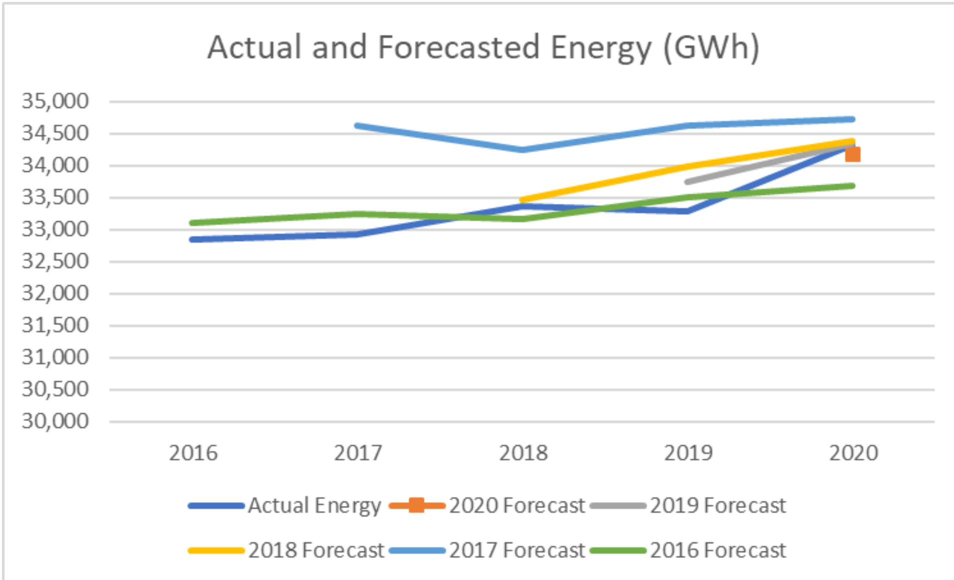


Figure 2.2-21 Forecast Comparison to Actual Summer Native Peak Demand

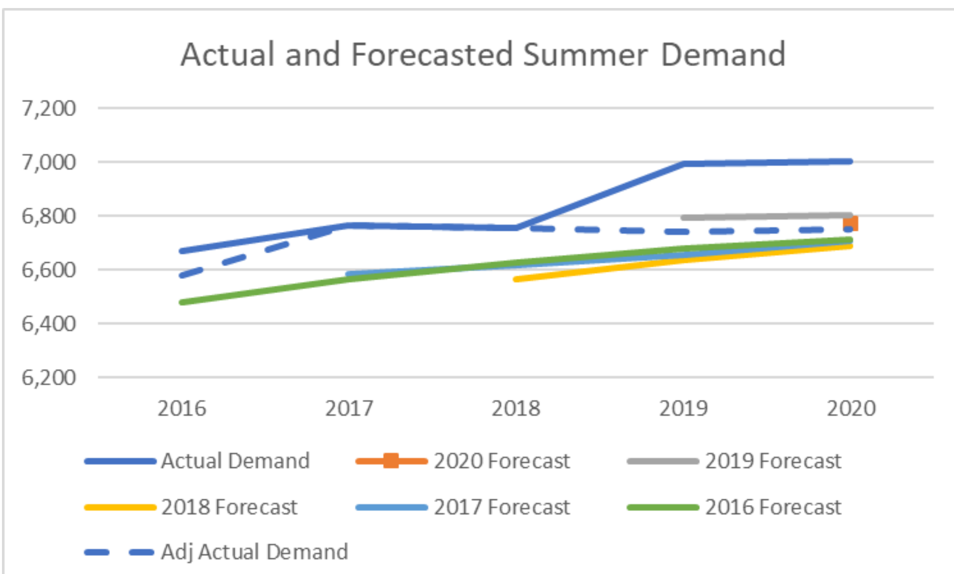
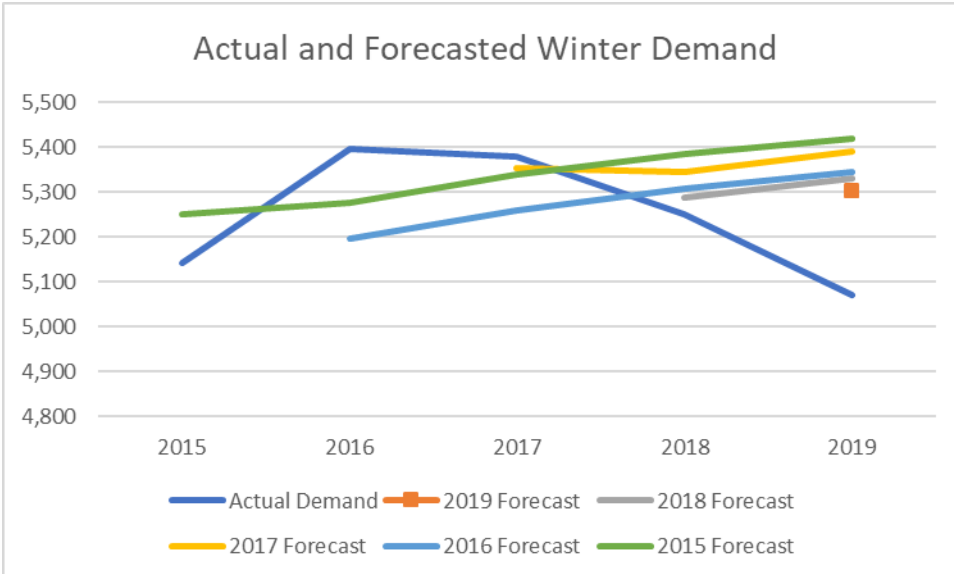


Figure 2.2-22 Forecast Comparison to Actual Winter Native Peak Demand



Description and Justification

Tables 2.2-26 through 2.2-42 show the parameters associated with Public Service's econometric forecasting models.

Table 2.2-26 Number of Residential Electric Customers

REGRESSION PERIOD: Jan 2006 through Jul 2020				
NUMBER OF OBSERVATIONS: 161				
LINEAR LEAST SQUARES MODEL WITH ARMA ERRORS				
Residential Customers = C1*Population + C2*Aug08 + C3*Sep08				
ARMA (1,0) process applied to errors				
Variable	Coefficient	StdErr	T-Stat	P-Value
C1	338.234	2.367	142.903	0.00%
C2	2,092.251	381.199	5.489	0.00%
C3	1,847.215	377.435	4.894	0.00%
AR(1)	1.287	0.075	17.127	0.00%
AR(2)	(0.301)	0.074	(4.090)	0.01%
SAR(1)	0.567	0.060	9.415	0.00%

Table 2.2-27 Residential Electric Customers – Regression Statistics

Regression Statistics	
Iterations	20
Adjusted Observations	161
Deg. of Freedom for Error	155
R-Squared	1.000
Adjusted R-Squared	1.000
AIC	12.784
BIC	12.899
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	(1252)
Model Sum of Squares	431,319,207,614.51
Sum of Squared Errors	53,289,232.37
Mean Squared Error	343,801.50
Std. Error of Regression	586.35
Mean Abs. Dev. (MAD)	442.17
Mean Abs. % Err. (MAPE)	0.04%
Durbin-Watson Statistic	2.05
Durbin-H Statistic	#NA
Ljung-Box Statistic	43.77
Prob (Ljung-Box)	0.008
Frequency of historical data is monthly	

Table 2.2-28 Residential Electric Customers – Definitions and Sources

Variable Name	Definition/Source
Residential Customers	Public Service residential electric customers / Public Service
Population	Population for the following metro cities: Denver, Aurora, Lakewood, Greeley, Boulder and Grand Junction.

Table 2.2-29 Residential Electric Sales per Customer

SAMPLE PERIOD: Jan 2003 through Jul 2020				
NUMBER OF OBSERVATIONS: 209				
LINEAR LEAST SQUARES MODEL WITH ARMA ERRORS				
AvgRes_Use = C1*Cooling + C2*Heating +C3*Base + C4*Jan + C5*Jun + C76*Jul + C7*Aug + C8*Dec + C9*Jan07 +C10*Aug12 + C11*Covid_19_Impact)May2020				
ARMA(1,0) process applied to errors				
Variable	Coefficient	StdErr	T-Stat	P-Value
C1	0.996	0.042	23.459	0.00%
C2	0.997	0.029	34.160	0.00%
C3	0.982	0.014	68.628	0.00%
C4	61.603	5.704	10.800	0.00%
C5	61.802	5.431	11.379	0.00%
C6	91.385	5.938	15.389	0.00%
C7	57.456	7.065	8.132	0.00%
C8	30.071	5.183	5.801	0.00%
C9	94.714	20.397	4.644	0.00%
C10	(60.385)	20.306	(2.974)	0.33%
C11	27.058	17.027	1.589	11.36%
AR(1)	0.349	0.071	4.919	0.00%
AR(2)	0.226	0.070	3.213	0.15%

Table 2.2-30 Residential Electric Sales per Customer – Regression Statistics

Regression Statistics	
Iterations	13
Adjusted Observations	209
Deg. of Freedom for Error	196
R-Squared	0.958
Adjusted R-Squared	0.955
AIC	6.175
BIC	6.383
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-928.89
Model Sum of Squares	2010606.26
Sum of Squared Errors	88729.84
Mean Squared Error	452.70
Std. Error of Regression	21.28
Mean Abs. Dev. (MAD)	16.20
Mean Abs. % Err. (MAPE)	2.5%
Durbin-Watson Statistic	2.01
Durbin-H Statistic	#NA
Ljung-Box Statistic	64.29
Prob (Ljung-Box)	0.000
Frequency of historical data is monthly	

Table 2.2-31 Residential Electric Sales per Customer – Definitions and Sources

Variable Name	Definition/Source
AvgRes_Use	Residential kWh sales per customer/Public Service
Cooling	CoolIndex * CoolUse CoolUse = Price^(-0.15)) * (Income per Household^0.2) * (Household Size^0.25) * Cooling Degree Days/Public Service, IHS Markit.
Heating	HeatIndex * HeatUse HeatUse = Price^(-0.15)) * (Income per Household^0.2) * (Household Size^0.25) * Heating Degree Days/Public Service, IHS Markit.
Base	BaseIndex * BaseUse BaseUse = Price^(-0.15)) * (Income per Household^0.1) * (Household Size^0.46) * Cooling Degree Days/Public Service, IHS Markit.
Jan-Dec	Binary variable for each month except February, March, April, May, September, October and November
Jan07	Binary variable = 0 for all months except January 2007 = 1
Aug12	Binary variable = 0 for all months except August 2012 =1
COVID_19_Impact_May2020	Binary variable = 1 beginning May 2020 and slowly declines throughout the forecast cycle

Table 2.2-32 Commercial & Industrial Electric Sales

SAMPLE PERIOD: Jan 2006 through July 2020				
NUMBER OF OBSERVATIONS: 175				
LINEAR LEAST SQUARES MODEL WITH ARMA ERRORS				
MWh = C1*CI_Custs + C2*XHeat + C3*XCool + C4*XOther + C5*Feb + C6*Apr + C7*May + C8*Nov + C9*Apr2020 + C10*May2020 + C11*Jun2020				
ARMA(1,0) process applied to errors				
Variable	Coefficient	StdErr	T-Stat	P-Value
C1	6.30	0.20	31.61	0.00%
C2	0.55	0.09	5.99	0.00%
C3	0.91	0.07	13.25	0.00%
C4	0.28	0.03	11.03	0.00%
C5	(103,952.25)	13,544.97	(7.67)	0.00%
C6	(92,663.17)	12,252.56	(7.56)	0.00%
C7	(66,950.08)	12,636.10	(5.30)	0.00%
C8	(102,325.07)	12,733.32	(8.04)	0.00%
C9	(68,127.74)	43,201.78	(1.58)	11.67%
C10	(135,227.88)	43,675.28	(3.10)	0.23%
C11	(161,781.10)	42,014.75	(3.85)	0.02%

Table 2.2-33 Commercial & Industrial Electric Sales – Regression Statistics

Regression Statistics	
Iterations	1
Adjusted Observations	175
Deg. of Freedom for Error	164
R-Squared	0.87
Adjusted R-Squared	0.87
AIC	21.31
BIC	21.51
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	(2,102.06)
Model Sum of Squares	1,932,019,165,378.14
Sum of Squared Errors	277,884,534,390.61
Mean Squared Error	1,694,417,892.63
Std. Error of Regression	41,163.31
Mean Abs. Dev. (MAD)	30,685.67
Mean Abs. % Err. (MAPE)	2.20%
Durbin-Watson Statistic	2.15
Durbin-H Statistic	#NA
Ljung-Box Statistic	119.88
Prob (Ljung-Box)	0.00
Frequency of historical data is monthly	

Table 2.2-34 Commercial & Industrial Electric Sales – Definitions and Sources

Variable Name	Definition/Source
MWh	Commercial/Industrial Electric Sales/Public Service
CI Custs	Historical and forecasted Commercial/Industrial customers/Public Service
Cooling	CoolIndex * CoolUse = Price^(-0.15)) * (Com.Output Index^0.25) * Cooling Degree Days/Public Service, IHS Markit.
Heating	HeatIndex * HeatUse = Price^(-0.15)) * (Com.Output Index^0.25) * Heating Degree Days/Public Service, IHS Markit.
Base	BaseIndex * BaseUse = Price^(-0.15)) * (Com.Output Index^0.25) * Heating Degree Days/Public Service, IHS Markit.
Feb, Apr, May and Nov	Binary variable for each month February, April, May and November
Apr 2020	Binary variable = 0 for all months except April 2020 = 1
May 2020	Binary variable = 0 for all months except May 2020 =1
Jun 2020	Binary variable = 0 for all months except June 2020 =1

Table 2.2-35 Electric Street and Highway Lighting Sales – Regression Statistics

Regression Statistics	
Iterations	14
Adjusted Observations	161
Deg. of Freedom for Error	141
R-Squared	1.00
Adjusted R-Squared	0.99
AIC	10.72
BIC	11.10
F-Statistic	1,660.23
Prob (F-Statistic)	0.00
Log-Likelihood	(1,071.28)
Model Sum of Squares	1,269,269,317.80
Sum of Squared Errors	5,673,495.80
Mean Squared Error	40,237.56
Std. Error of Regression	200.59
Mean Abs. Dev. (MAD)	122.18
Mean Abs. % Err. (MAPE)	0.86%
Durbin-Watson Statistic	2.07
Durbin-H Statistic	#NA
Ljung-Box Statistic	20.90
Prob (Ljung-Box)	0.64
Frequency of historical data is monthly	

Table 2.2-36 Electric Street and Highway Lighting Sales – Definitions and Sources

Variable Name	Definition/Source
Streetlight	Public Service Street and Highway Lighting Electric Sales/Public Service
Mins_Lights	Number minutes during the day that do not have sunlight
Jan-Dec	Binary variables for each month except January, February and December
Jan2013	Binary variable = 0 for all months except January 2013 = 1
Feb2013	Binary variable = 0 for all months except February 2013 = 1
Feb2016	Binary variable = 0 for all months except February 2016 = 1
Nov2019	Binary variable = 0 for all months except November 2019 = 1
Dec2019	Binary variable = 0 for all months except December 2019 =1
Jan2020	Binary variable = 0 for all months except January 2020 =1
Feb2020	Binary variable = 0 for all months except February 2020 =1

Table 2.2-37 Residential Contribution to System Peak Demand

SAMPLE PERIOD: Jan 2002 through Jul 2020				
NUMBER OF OBSERVATIONS: 222				
LINEAR LEAST SQUARES MODEL				
Res_Coincident = C1*Res_Native_Adj + C2*May_CDD_Index_Cust + C3*Jun_CDD_Index_Cust + C4*Jul_CDD_Index_Cust + C5*Aug_CDD_Index_Cust + C6*Sep_CDD_Index_Cust +C7*Oct_HDD_Index_Cust + C8*Nov_HDD_Index_Cust + C9*Dec_HDD_Index_Cust + C10*Jan_HDD_Index_Cust + C11*Feb_HDD_Index_Cust + C12*Mar_HDD_Index_Cust + C13*Apr_HDD_Index_Cust +C14*Sep2014 + C15*Apr2016 + C16*Sep08_LaborDay + C17*Hour_15 + C18*Hour_16 + C19*Hour_17 + C20*Hour_18 + C21*Hour_19				
ARMA(1,0,0) x (0,0,0) process applied to errors				
Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
C1	0.0017642	0.0000563	31.35	0.00%
C2	0.0000230	0.0000032	7.25	0.00%
C3	0.0000420	0.0000017	25.29	0.00%
C4	0.0000434	0.0000015	28.43	0.00%
C5	0.0000444	0.0000018	24.61	0.00%
C6	0.0000453	0.0000025	180	0.00%
C7	0.0000023	0.0000011	2.04	4.22%
C8	0.0000029	0.0000008	3.80	0.02%
C9	0.0000059	0.0000006	9.95	0.00%
C10	0.0000053	0.0000007	7.72	0.00%
C11	0.0000040	0.0000007	5.75	0.00%
C12	0.0000033	0.0000009	3.76	0.02%
C13	0.0000033	0.0000012	2.76	0.63%
C14	809.50	135.46	5.98	0.00%
C15	(485.67)	136.67	(3.55)	0.05%
C16	727.04	135.52	5.37	0.00%
C17	(380.66)	77.83	(4.89)	0.00%
C18	(261.86)	50.31	(5.21)	0.00%
C19	(123.15)	46.42	(2.65)	0.86%
C20	165.78	45.61	3.63	0.04%
C21	186.87	45.56	4.10	0.01%
AR(1)	0.167	0.07	2.32	2.16%

Table 2.2-38 Residential Contribution to System Peak Demand – Regression Statistics

Regression Statistics	
Iterations	11
Adjusted Observations	222
Deg. of Freedom for Error	200
R-Squared	0.909
Adjusted R-Squared	0.899
AIC	9.89
BIC	10.23
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,391.17
Model Sum of Squares	35,820,520.10
Sum of Squared Errors	3,605,189.88
Mean Squared Error	18,025.95
Std. Error of Regression	134.26
Mean Abs. Dev. (MAD)	101.45
Mean Abs. % Err. (MAPE)	5.9%
Durbin-Watson Statistic	2.03
Durbin-H Statistic	#NA
Ljung-Box Statistic	22.75
Prob (Ljung-Box)	0.53
Skewness	0.077
Frequency of historical data is monthly	

Table 2.2-39 Residential Contribution to System Peak Demand – Definitions and Sources

Variable Name	Definition/Source
Res_Conincident	Residential class contribution to system peak (MW) / Public Service
Res_Native_Adj	12 month moving average of actual and forecast Residential kWh sales / Public Service (calculated internally in the sales model)
CDD_Index_Cust	Max Cooling Degree Days (base 65) * Residential Cooling Index * Customer counts for the months of May, June, July, August and September
HDD_Index_Cust	Max Heating Degree Days (base 65) * Residential Heating Index * Customer counts for the months of October, November, December, January, February, March and April
Sep2014	Binary variable = 0 for all months except September 2014 = 1
Apr2016	Binary variable = 0 for all months except April 2016 = 1
Sep08_LaborDay	Binary variable = 0 for all months except September 2008 =1
Peak_Hr_Bin	Binary variable = 0 for all months except for hours_15, hour_16, hour_17, hour_18 and hour_19 = 1 if the peak occurred in the designated hour

Table 2.2-39 Non-Residential Contribution to System Peak Demand

SAMPLE PERIOD: Jan 2002 through Jul 2020				
NUMBER OF OBSERVATIONS: 150				
LINEAR LEAST SQUARES MODEL				
NonRes_Coincident = C1 + C2*NonRes_Native_Adj + C3*Jun_CDD_Index_Cust + C4*Jul_CDD_Index_Cust + C5*Aug_CDD_Index_Cust + C65*Sep_CDD_Index_Cust + C7*Jan + C8*Feb + C9*Mar + C10*Apr + C11*Oct + C12*Nov + C13*Dec + C14*Apr2006 + C15*Apr2007 + C16*Sep2008 + C17*Apr2012 + C18*May2015 + C19*May2017 + C20*Hour_18 + C21*COVID_April				
Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
C1	2,065.49	262.73	7.86	0.00%
C2	0.000613	0.00	3.67	0.03%
C3	0.000136	0.00	5.19	0.00%
C4	0.000189	0.00	8.26	0.00%
C5	0.000183	0.00	6.75	0.00%
C6	0.000098	0.00	2.37	1.87%
C7	(470.13)	51.41	(9.14)	0.00%
C8	(472.48)	51.94	(9.10)	0.00%
C9	(621.83)	52.25	(11.90)	0.00%
C10	(708.73)	54.88	(12.91)	0.00%
C11	(418.54)	52.33	(8.00)	0.00%
C12	(317.14)	53.45	(5.93)	0.00%
C13	(313.14)	53.46	(5.86)	0.00%
C14	674.12	171.33	3.93	0.01%
C15	780.63	170.68	4.57	0.00%
C16	(763.86)	168.24	(4.54)	0.00%
C17	697.81	170.70	4.09	0.01%
C18	(610.76)	169.83	(3.60)	0.04%
C19	(460.41)	170.73	(2.70)	0.76%
C20	(119.70)	32.11	(3.73)	0.03%
C21	(298.60)	87.49	(3.41)	0.08%

Table 2.2-40 Non-Residential Contribution to System Peak Demand – Regression Statistics

Regression Statistics	
Iterations	1
Adjusted Observations	223
Deg. of Freedom for Error	202
R-Squared	0.852
Adjusted R-Squared	0.837
AIC	10.31
BIC	10.63
F-Statistic	58.01
Prob (F-Statistic)	0.00
Log-Likelihood	(1,444.64)
Model Sum of Squares	31,764,065.08
Sum of Squared Errors	5,530,011.33
Mean Squared Error	27,376.29
Std. Error of Regression	165.46
Mean Abs. Dev. (MAD)	118.26
Mean Abs. % Err. (MAPE)	0.04
Durbin-Watson Statistic	1.74
Durbin-H Statistic	#NA
Ljung-Box Statistic	30.83
Prob (Ljung-Box)	0.159
Frequency of historical data is monthly	

Table 2.2-41 Non-Residential Contribution to System Peak Demand – Definitions and Sources

Variable Name	Definition/Source
NonRes_Conincident	Commercial and industrial class contribution to system peak (MW) / Public Service
NonRes_SalesTrend	12 month moving average of actual and forecast Non-Residential kWh sales / Public Service (calculated internally in the sales model)
CDD_Index_Cust	Max Cooling Degree Days (base 65) * Residential Cooling Index * Customer counts for the months of June, July, August and September
Jan-Dec	Binary variables for each month except May, June, July, August and September
Apr2006	Binary variable = 0 for all months except April 2006 = 1
Apr2007	Binary variable = 0 for all months except April 2007 = 1
Sep2008	Binary variable = 0 for all months except September 2008 =1
Apr2012	Binary variable = 0 for all months except April 2012 =1
May2015	Binary variable = 0 for all months except May 2015 =1
May2017	Binary variable = 0 for all months except May 2017 =1
Hour_18	Binary variable = 0 for all months except for hour_18 = 1 if the peak occurred in the designated hour
COVID_April	Binary variable = 1 beginning April - December 2020; 0.5 from January - December 2021; 0 for all other months

2.3 TYPICAL DAY LOAD PATTERNS

In this Section, the Company provides typical day load patterns on a system-wide basis for each major customer class (by voltage level), provided for peak day, average day, and representative off-peak days for each calendar month as required by Rule 3606(a)(VI).

The following monthly class load shapes are developed from Company load research data for the year 2019. The following statistics were used for each requirement:

Requirement	**Statistic**
Peak Day	System Peak Day
Average Day	Average Weekday Excluding Holidays
Representative Off-Peak Day	Average Weekends and Holidays

The residential and commercial and industrial profiles were developed from aggregated load research classes. These profiles were calculated using the population weighted average load of all the rate classes in each group.

Figures 2.3-1 through 2.3-60 in this section contain tables and graphs for each of the load patterns described above. The figures are grouped according to the following categories:

Residential	Figures 2.3-1 through 2.3-12
Commercial & Industrial (Secondary)	Figures 2.3-13 through 2.3-24
Commercial & Industrial (Primary)	Figures 2.3-25 through 2.3-36
Commercial & Industrial (Transmission)	Figures 2.3-37 through 2.3-48
Wholesale	Figures 2.3-49 through 2.3-60

The wholesale data provided for two wholesale customers who are part owners in Comanche Unit 3 contains their total load. Public Service is required to serve their total load in the event that Comanche 3 is not online. In addition, the Western Area Power Administration ("WAPA") allocations for the wholesale data are not subtracted from the total load provided because hourly WAPA data is not available.

Figure 2.3-1 January Residential Daily Load Profiles

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.0340	0.7603	0.7943
2	0.9686	0.7230	0.7524
3	0.9151	0.7127	0.7210
4	0.9145	0.7065	0.7079
5	0.9062	0.7411	0.7201
6	0.8833	0.8064	0.7489
7	0.9358	0.9206	0.7904
8	0.9698	1.0020	0.8588
9	1.0366	0.8990	0.9446
10	1.0945	0.8432	0.9484
11	1.1018	0.8292	0.9508
12	1.0987	0.8098	0.9581
13	1.1368	0.8058	0.9570
14	1.0325	0.7617	0.9357
15	1.0682	0.7677	0.9316
16	1.1465	0.7819	0.9435
17	1.2024	0.8744	1.0282
18	1.3021	1.0852	1.1825
19	1.4900	1.2014	1.2332
20	1.3853	1.2135	1.1979
21	1.3402	1.2068	1.1864
22	1.2559	1.1081	1.0972
23	1.1130	0.9493	0.9499
24	1.0045	0.8362	0.8489

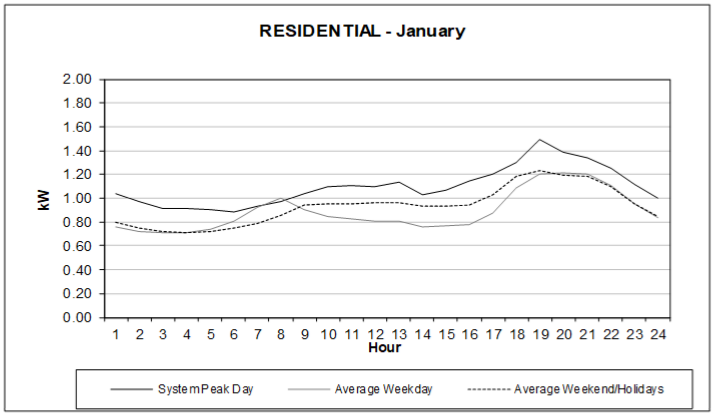


Figure 2.3-2 February Residential Daily Load Profiles

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.6823	0.7382	0.7555
2	0.6676	0.7145	0.7161
3	0.6743	0.7040	0.7034
4	0.6608	0.6979	0.6886
5	0.6996	0.7356	0.7083
6	0.7586	0.7980	0.7443
7	0.8865	0.9138	0.7935
8	0.9456	0.9702	0.8596
9	0.8863	0.8701	0.9186
10	0.8375	0.8197	0.9348
11	0.8927	0.8101	0.8895
12	0.8553	0.7833	0.8878
13	0.9298	0.7709	0.8902
14	0.9125	0.7687	0.9452
15	0.9076	0.7592	0.9219
16	1.0239	0.7784	0.9137
17	1.0997	0.8522	0.9816
18	1.2924	1.0237	1.0845
19	1.4816	1.1883	1.1680
20	1.3893	1.2005	1.1464
21	1.2868	1.1726	1.1311
22	1.2454	1.0817	1.0511
23	1.0382	0.9312	0.9093
24	0.9035	0.8022	0.7977

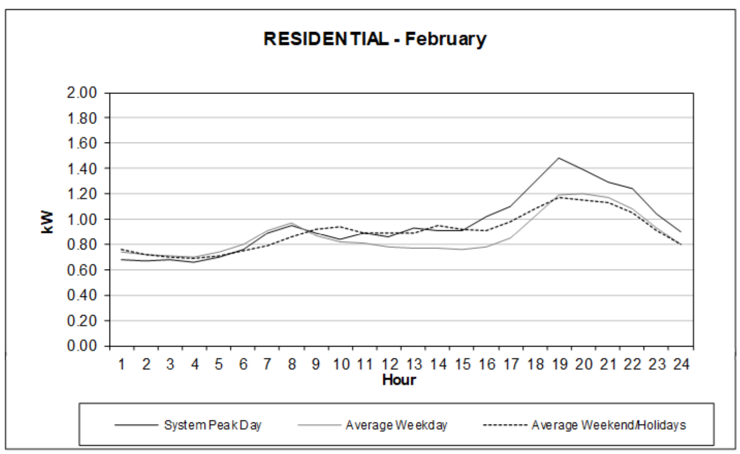


Figure 2.3-3 March Residential Daily Load Profiles

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.8101	0.6672	0.6852
2	0.7609	0.6255	0.6418
3	0.7599	0.6082	0.6321
4	0.7692	0.6116	0.6232
5	0.7755	0.6394	0.6391
6	0.8010	0.7133	0.6743
7	0.8346	0.8176	0.7203
8	1.0140	0.8704	0.8066
9	1.1044	0.7932	0.8695
10	1.0854	0.7514	0.9172
11	1.1207	0.7262	0.9208
12	1.1200	0.7214	0.8918
13	1.1165	0.7088	0.8711
14	1.2036	0.6921	0.8831
15	1.2051	0.6859	0.8755
16	1.2009	0.7050	0.8645
17	1.1884	0.7787	0.8950
18	1.3265	0.8734	0.9618
19	1.4348	0.9900	1.0236
20	1.4328	1.0476	1.0615
21	1.3063	1.0398	1.0451
22	1.2263	0.9835	0.9870
23	1.0216	0.8552	0.8936
24	0.9438	0.7476	0.8068

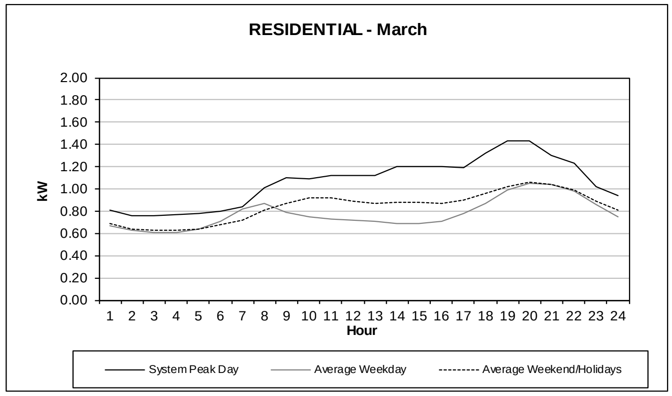


Figure 2.3-4 April Residential Daily Load Profiles

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.5061	0.5705	0.5807
2	0.4796	0.5286	0.5318
3	0.4671	0.5084	0.4957
4	0.4394	0.5022	0.4866
5	0.4857	0.5230	0.4869
6	0.5506	0.5990	0.5363
7	0.6606	0.6963	0.5790
8	0.7063	0.7502	0.6486
9	0.6724	0.6863	0.7091
10	0.7029	0.6688	0.7617
11	0.7689	0.6679	0.7878
12	0.7040	0.6612	0.7859
13	0.6934	0.6518	0.7906
14	0.7423	0.6489	0.7948
15	0.7795	0.6490	0.7779
16	0.8321	0.6687	0.7733
17	0.9573	0.7233	0.7898
18	1.0460	0.8024	0.8408
19	1.1453	0.8867	0.8465
20	1.1562	0.9398	0.9000
21	1.1252	0.9479	0.9149
22	1.0167	0.9138	0.8835
23	0.9149	0.8067	0.7712
24	0.7697	0.6705	0.6514

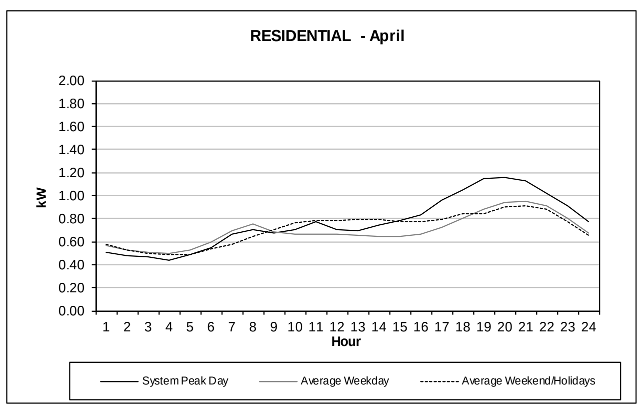


Figure 2.3-5 May Residential Daily Load Profiles

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.5517	0.5718	0.5532
2	0.5146	0.5204	0.4953
3	0.4613	0.5010	0.4739
4	0.4564	0.4960	0.4624
5	0.4503	0.5069	0.4664
6	0.5047	0.5809	0.4970
7	0.5934	0.6559	0.5455
8	0.6704	0.7058	0.6205
9	0.5954	0.6471	0.6723
10	0.5856	0.6373	0.6941
11	0.6073	0.6303	0.7318
12	0.6920	0.6417	0.7212
13	0.7222	0.6445	0.7163
14	0.7669	0.6557	0.7271
15	0.7952	0.6630	0.7208
16	0.8904	0.6860	0.7322
17	0.9797	0.7551	0.7688
18	1.0615	0.8530	0.8350
19	1.2133	0.9139	0.8426
20	1.2220	0.9275	0.8605
21	1.2215	0.9368	0.9005
22	1.1289	0.8977	0.8573
23	0.9351	0.7922	0.7735
24	0.8081	0.6691	0.6547

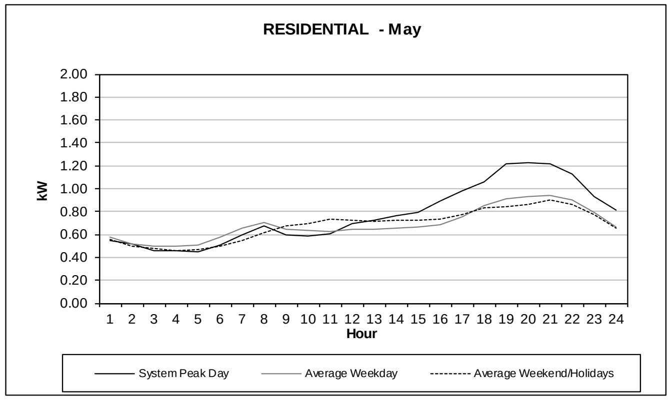


Figure 2.3-6 June Residential Daily Load Profiles

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.9066	0.6289	0.6955
2	0.7359	0.5497	0.6160
3	0.6633	0.5009	0.5535
4	0.6107	0.4718	0.5186
5	0.5489	0.4702	0.5017
6	0.5718	0.5154	0.5126
7	0.6203	0.5625	0.5572
8	0.6301	0.6096	0.6342
9	0.7567	0.6201	0.7240
10	0.8068	0.6324	0.8117
11	0.9836	0.6815	0.8787
12	1.1434	0.7426	0.9333
13	1.3891	0.8142	1.0150
14	1.5854	0.8733	1.0657
15	1.7326	0.9432	1.0881
16	1.9764	1.0116	1.0692
17	2.0652	1.0927	1.1204
18	2.1068	1.1757	1.1301
19	2.1044	1.2133	1.1341
20	1.9300	1.1808	1.0680
21	1.7940	1.1314	1.0404
22	1.7003	1.0984	1.0294
23	1.6012	0.9664	0.9114
24	1.2592	0.8003	0.7627

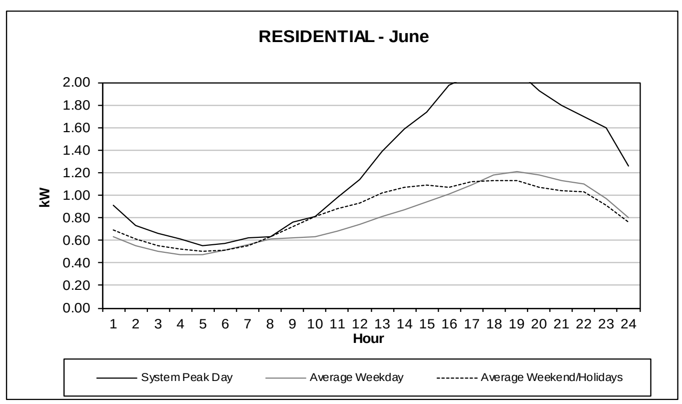


Figure 2.3-7 July Residential Daily Load Profiles

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.1788	0.8503	0.8948
2	0.9660	0.7379	0.7768
3	0.8253	0.6605	0.6988
4	0.7576	0.6047	0.6407
5	0.6530	0.5766	0.6038
6	0.6676	0.5984	0.5844
7	0.7361	0.6425	0.6000
8	0.8268	0.7103	0.6905
9	0.9381	0.7909	0.8363
10	1.0678	0.8695	0.9519
11	1.2203	0.9635	1.0555
12	1.3061	1.1226	1.1984
13	1.5206	1.2594	1.3401
14	1.7320	1.4177	1.4701
15	1.8671	1.5386	1.5692
16	1.9801	1.6338	1.6386
17	2.1452	1.7080	1.6813
18	2.1257	1.7756	1.6733
19	2.0519	1.8007	1.5989
20	1.9466	1.6636	1.4733
21	2.0095	1.5468	1.3259
22	1.8873	1.4441	1.2713
23	1.6760	1.2857	1.1523
24	1.5467	1.0857	0.9808

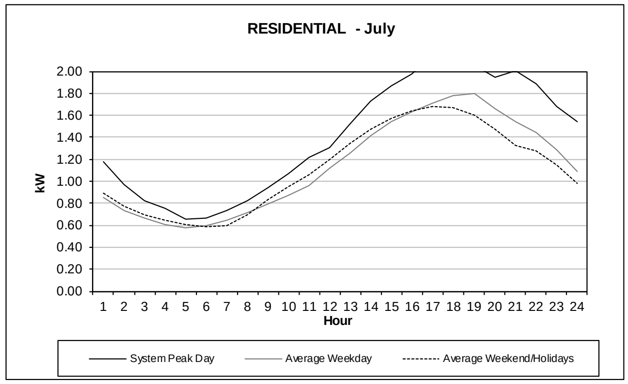


Figure 2.3-8 August Residential Daily Load Profiles

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.9634	0.8232	0.8380
2	0.7846	0.7095	0.7192
3	0.7279	0.6352	0.6518
4	0.6268	0.5826	0.6059
5	0.5871	0.5626	0.5686
6	0.6047	0.5932	0.5624
7	0.6942	0.6549	0.5752
8	0.7524	0.6928	0.6459
9	0.7819	0.7267	0.7590
10	0.8340	0.7721	0.8769
11	1.0145	0.8801	1.0337
12	1.1545	1.0010	1.1623
13	1.3438	1.1557	1.3335
14	1.5966	1.3033	1.5005
15	1.7627	1.4249	1.5889
16	1.8765	1.5259	1.6589
17	1.9725	1.6278	1.7131
18	2.0925	1.7270	1.7594
19	2.1324	1.7069	1.6940
20	1.9657	1.5830	1.5990
21	1.8617	1.4675	1.4598
22	1.6239	1.3465	1.3562
23	1.3954	1.1560	1.1915
24	1.1356	0.9825	1.0051

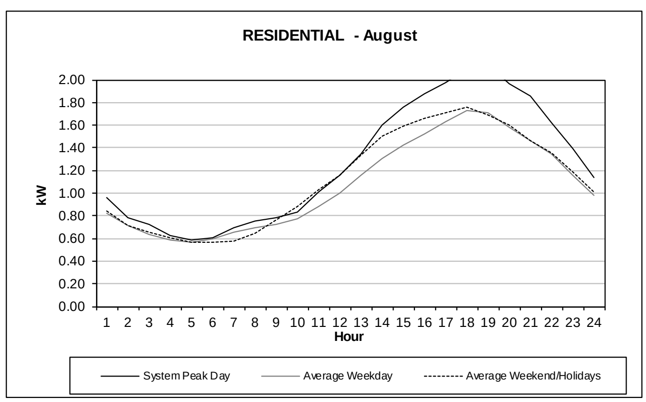


Figure 2.3-9 September Residential Daily Load Profiles

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.9109	0.6403	0.6414
2	0.8018	0.5603	0.5643
3	0.7335	0.4983	0.5184
4	0.6552	0.4772	0.4837
5	0.5999	0.4695	0.4644
6	0.5832	0.5219	0.4799
7	0.6120	0.5895	0.5231
8	0.6691	0.6208	0.5820
9	0.8305	0.6060	0.6632
10	0.9960	0.5988	0.7244
11	1.3375	0.6306	0.8316
12	1.5885	0.6923	0.9000
13	1.8194	0.7959	1.0293
14	1.9995	0.9051	1.1559
15	2.0479	1.0191	1.2557
16	2.1587	1.1012	1.3462
17	2.2251	1.1861	1.4035
18	2.3110	1.2465	1.4278
19	2.1447	1.2676	1.3705
20	2.0304	1.2280	1.2914
21	1.8435	1.1490	1.1834
22	1.6465	1.0213	1.0628
23	1.2699	0.8864	0.9264
24	1.0881	0.7399	0.7820

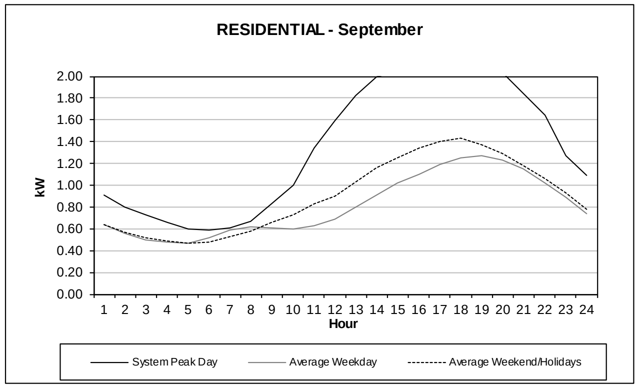


Figure 2.3-10 October Residential Daily Load Profiles

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.6687	0.5581	0.5316
2	0.6507	0.5160	0.4837
3	0.6184	0.5015	0.4761
4	0.6007	0.4960	0.4759
5	0.6548	0.5151	0.4810
6	0.7073	0.5774	0.5147
7	0.7941	0.6682	0.5701
8	0.8997	0.7502	0.6613
9	0.8861	0.7072	0.7187
10	0.8771	0.6565	0.7334
11	0.8793	0.6491	0.7502
12	0.8565	0.6533	0.7628
13	0.8820	0.6531	0.7694
14	0.8552	0.6266	0.7545
15	0.8438	0.6308	0.7347
16	0.8436	0.6687	0.7782
17	0.9576	0.7277	0.7805
18	1.0900	0.8196	0.8464
19	1.1668	0.9284	0.8967
20	1.2478	0.9850	0.9123
21	1.1682	0.9425	0.8817
22	1.0435	0.8509	0.7919
23	0.8922	0.7398	0.7270
24	0.8005	0.6303	0.6211

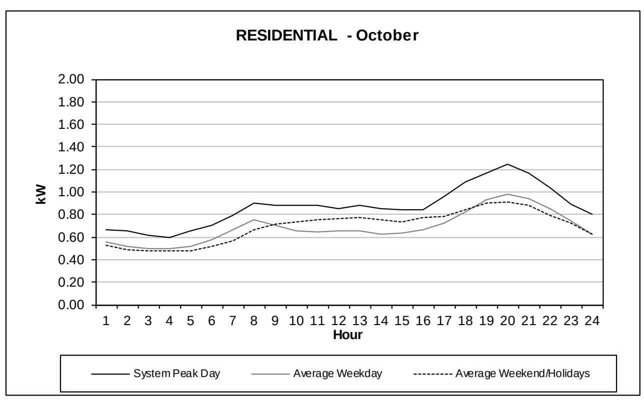


Figure 2.3-11 November Residential Daily Load Profiles

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.7448	0.6315	0.6713
2	0.7025	0.6017	0.6262
3	0.7223	0.5993	0.6091
4	0.7220	0.6018	0.6076
5	0.7431	0.6236	0.6130
6	0.8262	0.6892	0.6438
7	0.8952	0.7930	0.7161
8	0.9800	0.8450	0.8142
9	0.9585	0.7923	0.8755
10	0.9567	0.7471	0.8758
11	0.8888	0.7433	0.8723
12	0.8391	0.7330	0.8608
13	0.9430	0.7369	0.8526
14	0.9312	0.7290	0.8246
15	0.9270	0.7282	0.8180
16	0.9744	0.7623	0.8438
17	1.1334	0.8677	0.9228
18	1.2204	1.0096	1.0265
19	1.3083	1.1025	1.0636
20	1.3218	1.0784	1.0196
21	1.2257	1.0337	0.9874
22	1.1423	0.9574	0.9160
23	1.0201	0.8251	0.8192
24	0.9342	0.7231	0.7237

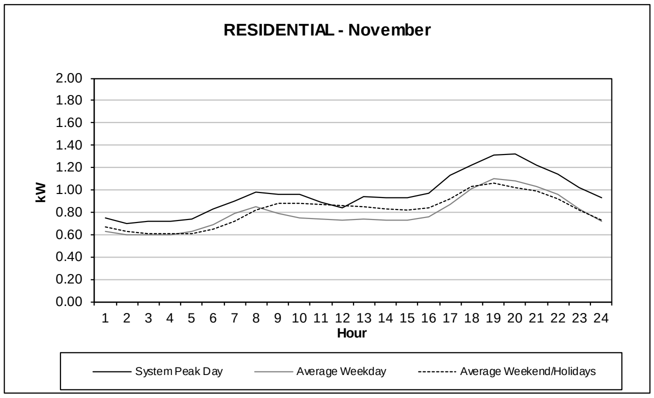


Figure 2.3-12 December Residential Daily Load Profiles

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.7444	0.7290	0.7619
2	0.6878	0.6991	0.7104
3	0.7046	0.6820	0.6973
4	0.7092	0.6861	0.6861
5	0.7202	0.6990	0.6898
6	0.8007	0.7713	0.7400
7	0.9652	0.8893	0.7958
8	1.0401	0.9386	0.8986
9	0.9148	0.9020	0.9688
10	0.8674	0.8502	0.9580
11	0.9180	0.8347	0.9654
12	0.8861	0.8199	0.9586
13	0.8921	0.8180	0.9586
14	0.8339	0.8013	0.9318
15	0.7928	0.7769	0.9274
16	0.8768	0.8046	0.9524
17	1.1237	0.9521	1.0697
18	1.3740	1.1541	1.1861
19	1.4483	1.2249	1.2118
20	1.4747	1.2072	1.1897
21	1.3893	1.1714	1.1497
22	1.3300	1.1013	1.0852
23	1.0504	0.9518	0.9501
24	0.8776	0.8176	0.8357

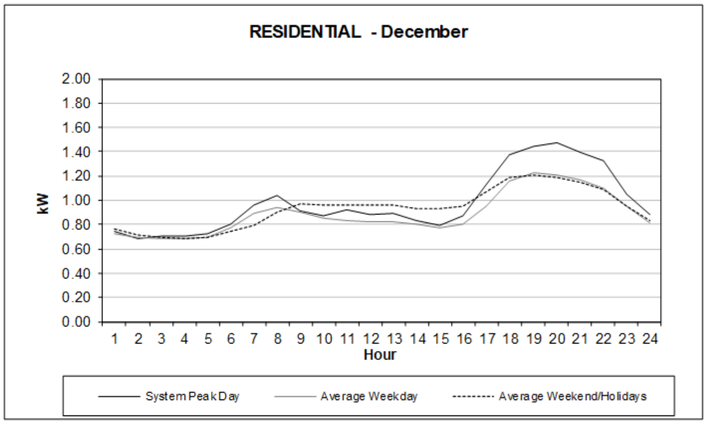


Figure 2.3-13 Commercial and Industrial (Secondary) January Daily Load Profiles

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	9.1801	8.0618	7.8869
2	9.1301	8.0197	7.8467
3	9.1045	8.1045	7.8889
4	9.0036	8.2466	7.9051
5	9.1481	8.6021	8.0404
6	9.3852	9.4381	8.2357
7	9.5355	10.7221	8.5608
8	9.5811	11.8228	8.6594
9	9.5764	12.6312	8.6897
10	9.4219	12.9274	8.7281
11	9.4338	12.9834	8.7437
12	9.3701	12.7175	8.6469
13	9.2435	12.4676	8.4807
14	9.0480	12.3429	8.2829
15	8.9233	12.1199	8.1215
16	8.8792	11.6754	7.9908
17	9.1737	11.0566	8.0922
18	9.6468	10.5407	8.3701
19	9.4723	9.7941	8.2675
20	9.3419	9.4207	8.2289
21	9.2987	9.0989	8.1327
22	9.1539	8.7063	7.9837
23	9.0413	8.3461	7.8618
24	8.8976	8.1686	7.7844

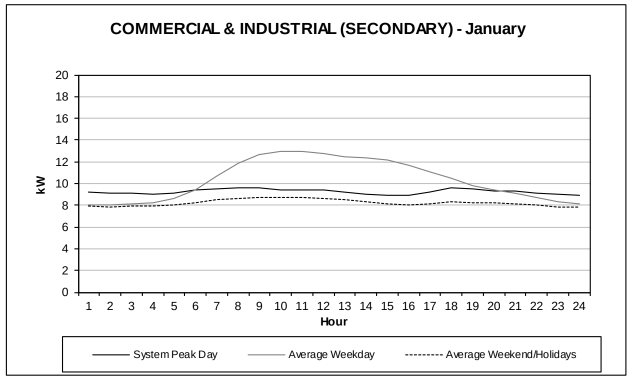


Figure 2.3-14 Commercial and Industrial (Secondary) February Daily Load Profiles

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7.5777	8.1328	7.8011
2	7.5192	8.1017	7.7796
3	7.6330	8.2326	7.8547
4	7.8705	8.3558	7.8843
5	8.3001	8.6482	7.9938
6	9.3229	9.5286	8.1690
7	10.7760	10.7843	8.4227
8	11.8941	11.7853	8.3812
9	12.9735	12.6819	8.4589
10	13.6352	13.0222	8.5269
11	13.8012	13.0621	8.5090
12	13.6340	12.8555	8.4669
13	13.5310	12.5790	8.4094
14	13.2975	12.4618	8.3184
15	12.8870	12.2458	8.2203
16	12.4361	11.8284	8.1474
17	11.8815	11.2034	8.2095
18	11.4108	10.5309	8.3204
19	10.7991	9.9452	8.4143
20	10.4789	9.5884	8.3325
21	10.2556	9.2988	8.2446
22	9.9578	8.8700	8.0997
23	9.5522	8.4419	7.9513
24	9.3006	8.2629	7.9027

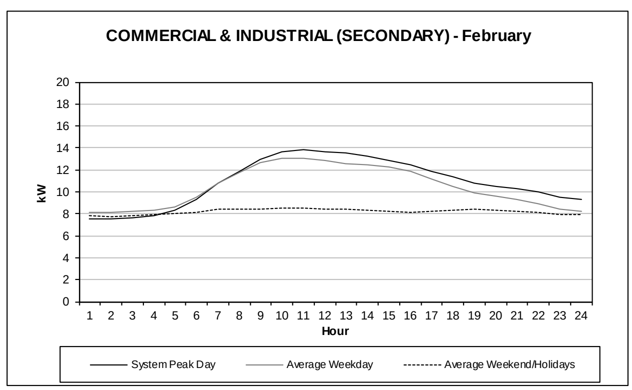


Figure 2.3-15 Commercial and Industrial (Secondary) March Daily Load Profiles

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8.8133	7.4089	7.3268
2	8.7094	7.3754	7.2802
3	8.7373	7.4450	7.3629
4	8.8144	7.5406	7.3789
5	8.8965	7.8256	7.4486
6	9.0334	8.6074	7.7373
7	9.1104	9.7882	7.9885
8	8.9584	10.7922	7.9915
9	9.1255	11.6864	8.0708
10	9.0993	12.0492	8.2032
11	9.0810	12.1279	8.2699
12	8.9879	11.9226	8.2380
13	9.0632	11.6448	8.1345
14	9.0992	11.6503	8.0403
15	9.3608	11.4638	7.9044
16	9.5962	11.0689	7.7360
17	9.5591	10.4452	7.7248
18	9.4718	9.5301	7.6053
19	9.5863	8.9025	7.6831
20	9.5003	8.7550	7.8345
21	9.5768	8.4838	7.8742
22	9.3582	8.1230	7.6956
23	9.1487	7.7215	7.5428
24	9.1636	7.5332	7.4754

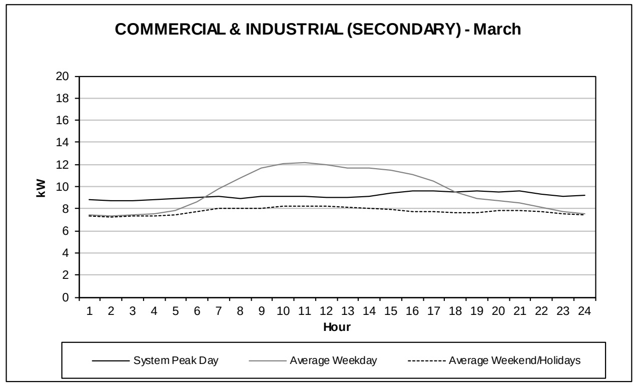


Figure 2.3-16 Commercial and Industrial (Secondary) April Daily Load Profiles

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	6.8932	6.9812	6.7729
2	6.7038	6.8704	6.6636
3	6.6955	6.8847	6.6113
4	6.7362	6.9850	6.6139
5	6.9334	7.2107	6.6241
6	7.8174	8.0933	6.8462
7	9.0927	9.2244	6.9877
8	10.4002	10.5013	7.1119
9	11.4927	11.7435	7.5861
10	12.7636	12.3077	7.8792
11	12.9932	12.5603	7.9938
12	13.1203	12.7395	8.0476
13	12.9864	12.6009	7.9975
14	13.0857	12.5706	7.9117
15	11.9328	12.4300	7.8169
16	10.8428	11.9169	7.5911
17	10.1698	10.9660	7.4616
18	9.5243	9.6038	7.1754
19	9.0725	8.7060	7.0012
20	9.0481	8.6545	7.0335
21	8.9750	8.5531	7.1060
22	8.6378	8.0465	6.9633
23	8.2348	7.5166	6.8427
24	8.1613	7.2951	6.7480

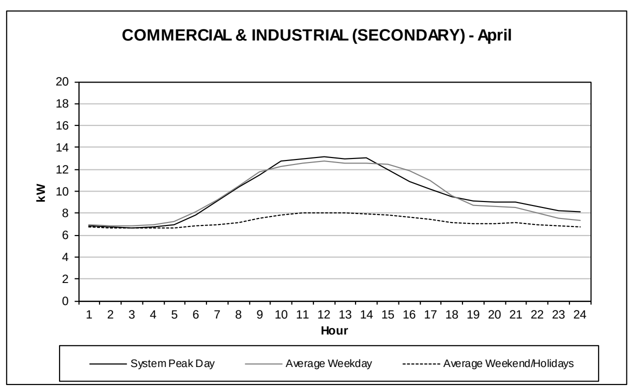


Figure 2.3-17 Commercial and Industrial (Secondary) May Daily Load Profiles

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7.3272	7.0383	6.5639
2	7.0923	6.8938	6.3580
3	7.0307	6.8848	6.2946
4	7.0912	6.9853	6.3626
5	7.2440	7.1505	6.3197
6	8.0171	7.9677	6.5061
7	8.9599	8.9055	6.5093
8	10.4192	10.3264	6.8168
9	11.6464	11.4377	7.2239
10	12.2384	11.9797	7.5425
11	12.7969	12.2239	7.7097
12	13.0621	12.3421	7.7795
13	13.0543	12.1607	7.7737
14	13.2535	12.2652	7.7762
15	13.9844	12.0902	7.6613
16	14.0751	11.6594	7.5420
17	13.1081	10.8704	7.3238
18	11.5610	9.8582	7.0525
19	9.6762	8.6185	6.8619
20	9.3655	8.4392	6.7435
21	9.3614	8.3663	6.9237
22	8.4056	7.8822	6.9269
23	7.6922	7.4020	6.8453
24	7.4015	7.2021	6.6986

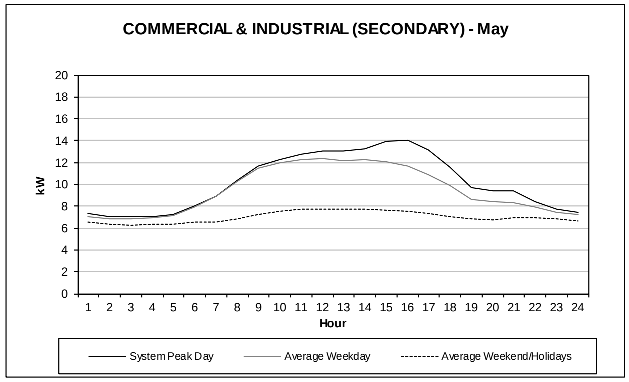


Figure 2.3-18 Commercial and Industrial (Secondary) June Daily Load Profiles

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8.2342	7.2662	7.1244
2	7.9148	7.0382	6.8613
3	7.7580	6.9082	6.6963
4	7.7638	6.9700	6.6072
5	7.9003	7.1924	6.6022
6	8.7993	8.1223	6.8043
7	9.5653	9.0056	6.8319
8	11.5742	10.8146	7.3376
9	12.5589	11.8441	7.9160
10	13.9837	12.5424	8.5260
11	14.3202	12.9513	8.9193
12	15.5963	13.5316	9.2800
13	15.5549	13.6403	9.4809
14	15.7393	13.7959	9.2787
15	15.9082	13.6900	8.8701
16	15.3729	13.2182	8.6856
17	14.0102	12.4821	8.4795
18	12.6474	11.2224	8.1268
19	11.2818	9.7895	7.7807
20	10.2518	9.1906	7.5527
21	9.7681	9.0358	7.5669
22	9.5544	8.7088	7.6570
23	8.8647	8.0255	7.5089
24	8.5155	7.6326	7.3252

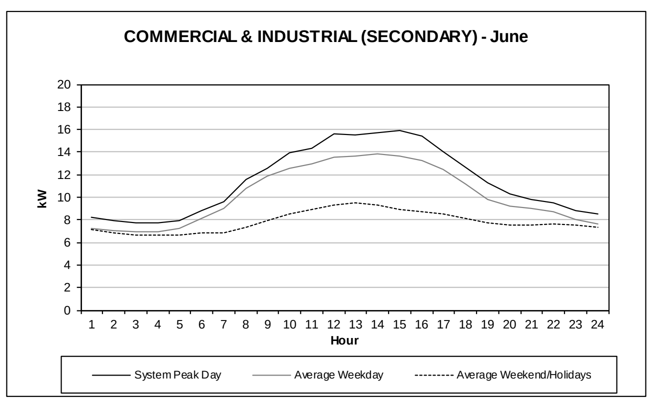


Figure 2.3-19 Commercial and Industrial (Secondary) July Daily Load Profiles

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	9.0783	8.0027	7.6917
2	8.8720	7.8331	7.4190
3	8.5332	7.7117	7.2399
4	8.6284	7.8077	7.2088
5	9.0068	8.1698	7.2325
6	9.8149	9.2178	7.5499
7	10.6909	10.0479	7.5285
8	11.9170	11.5980	8.0163
9	13.0779	12.8059	8.6117
10	14.7692	13.8259	9.1673
11	15.6796	14.5455	9.4970
12	16.1718	15.2882	10.1098
13	16.4481	15.4343	10.3602
14	16.6515	15.6282	10.2250
15	16.6154	15.6175	10.1967
16	16.4181	15.0668	10.0472
17	15.8568	13.8148	9.9868
18	14.5407	12.6066	9.5703
19	12.6133	11.1701	9.0642
20	11.6082	10.1822	8.6901
21	11.6868	10.0358	8.5599
22	11.2800	9.7073	8.4853
23	10.4008	8.8900	8.1668
24	9.1916	8.4646	7.8696

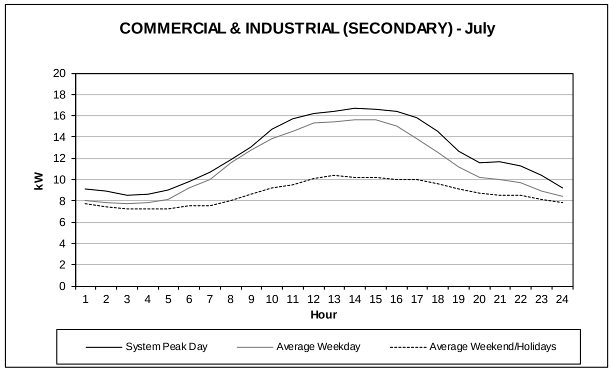


Figure 2.3-20 Commercial and Industrial (Secondary) August Daily Load Profiles

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8.3524	8.2093	7.8646
2	8.0624	7.9774	7.5598
3	7.8895	7.8866	7.4504
4	7.9337	8.0394	7.4569
5	8.5569	8.5570	7.5289
6	9.6718	9.4993	7.7174
7	10.6054	10.4172	7.7789
8	12.1824	11.8404	8.0605
9	13.7008	13.2121	8.6559
10	14.6722	14.2032	9.2778
11	15.6795	14.8591	9.8123
12	16.2390	15.4136	10.3336
13	16.3978	15.5626	10.5341
14	16.7098	15.7291	10.5147
15	16.8249	15.7237	10.4426
16	15.7359	15.1160	10.3510
17	14.7345	13.7265	10.2849
18	13.5150	12.5382	9.9530
19	11.8486	11.1468	9.5995
20	11.0753	10.3154	9.2383
21	11.0274	10.0422	9.2587
22	10.1565	9.4207	8.8484
23	9.3883	8.7163	8.4441
24	9.1191	8.4179	8.2841

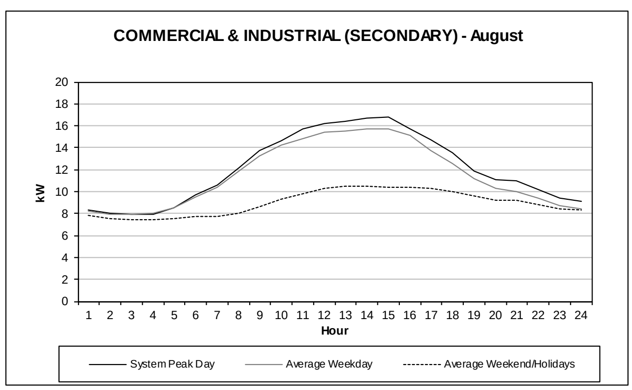


Figure 2.3-21 Commercial and Industrial (Secondary) September Daily Load Profiles

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8.3616	7.4837	7.2952
2	8.1379	7.2429	6.9935
3	8.1294	7.1899	6.9007
4	8.1899	7.2901	6.9169
5	8.1984	7.7598	6.9503
6	8.5009	8.6046	7.1065
7	8.3722	9.6491	7.3146
8	8.3207	10.8018	7.4037
9	8.7313	12.0881	7.7426
10	9.4448	13.0024	8.3574
11	9.9506	13.7134	8.8634
12	10.7847	14.1428	9.4646
13	11.0496	14.2340	9.6602
14	11.1928	14.5613	9.6581
15	11.3761	14.6046	9.5982
16	11.5606	14.0187	9.5868
17	11.4945	12.5253	9.4551
18	11.1555	11.3165	9.1932
19	10.4492	10.0813	8.6872
20	9.4223	9.7753	8.4946
21	9.0012	9.2065	8.2955
22	8.6427	8.6576	8.0476
23	8.2364	8.0263	7.7736
24	8.1050	7.7196	7.5614

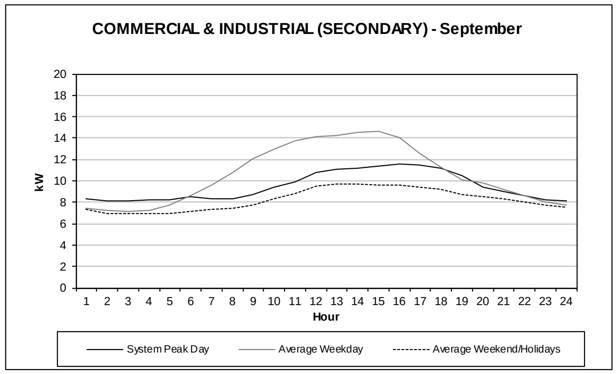


Figure 2.3-22 Commercial and Industrial (Secondary) October Daily Load Profiles

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8.1524	7.1739	6.5265
2	8.0135	7.0578	6.4736
3	7.9295	7.0903	6.4793
4	8.0401	7.2161	6.5297
5	8.2947	7.4863	6.5957
6	9.4026	8.4218	6.9180
7	10.6335	9.5442	7.3011
8	11.6328	10.6085	7.4264
9	12.3690	11.4882	7.4259
10	13.0491	11.9662	7.5443
11	13.0504	12.3947	7.6492
12	12.5607	12.4754	7.7073
13	12.1468	12.2839	7.6968
14	11.9146	12.3426	7.6319
15	11.7017	12.2453	7.5233
16	11.3139	11.8830	7.4261
17	10.8471	10.6835	7.3304
18	10.3424	9.6151	7.2024
19	10.1380	9.0687	7.4084
20	9.8680	8.8351	7.4351
21	9.4797	8.4567	7.3614
22	9.3529	8.0966	7.1831
23	9.0815	7.5866	6.9928
24	9.0173	7.3306	6.7902

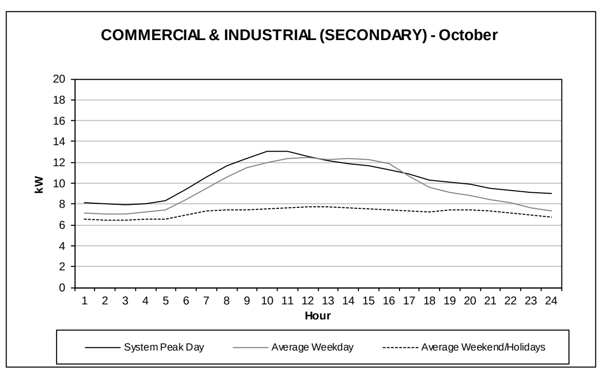


Figure 2.3-23 Commercial and Industrial (Secondary) November Daily Load Profiles

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8.2672	7.2839	7.2167
2	8.2433	7.2228	7.1639
3	8.3584	7.3402	7.1886
4	8.5177	7.4992	7.2289
5	8.9418	7.8627	7.3529
6	9.5414	8.6608	7.5846
7	10.4480	9.7036	7.9241
8	10.9224	10.5580	7.8958
9	11.3961	11.3641	7.9201
10	11.5523	11.7206	7.9867
11	11.5409	11.9471	8.0160
12	11.3457	11.9269	8.0103
13	11.0790	11.7548	7.9570
14	11.0961	11.7072	7.8146
15	11.0866	11.6714	7.6927
16	10.8000	11.3680	7.6001
17	10.6755	10.5439	7.5948
18	10.4011	9.8629	7.7264
19	9.7793	9.2019	7.6630
20	9.4930	8.8585	7.6517
21	9.3227	8.5190	7.5758
22	9.0607	8.1725	7.3926
23	8.6034	7.7230	7.1855
24	8.4704	7.5406	7.0972

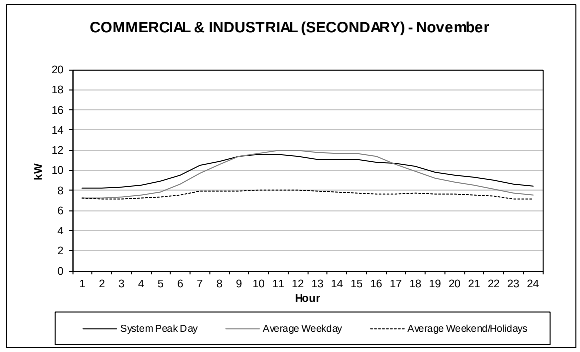


Figure 2.3-24 Commercial and Industrial (Secondary) December Daily Load Profiles

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8.0396	7.7713	7.5344
2	8.0089	7.7380	7.5184
3	8.0484	7.8505	7.5449
4	8.2260	8.0270	7.5941
5	8.5962	8.3226	7.7615
6	9.5598	9.1081	7.9587
7	10.6676	10.2064	8.2886
8	11.8814	11.0751	8.3809
9	12.7362	11.6439	8.2941
10	13.0915	11.9061	8.3681
11	13.3422	12.0643	8.3919
12	13.0423	11.9694	8.3874
13	13.3768	11.7479	8.2417
14	13.1721	11.6695	8.0956
15	12.9143	11.4848	7.8774
16	12.4193	11.0618	7.8027
17	11.5112	10.4107	8.0357
18	10.7792	9.8611	8.1293
19	10.0206	9.1739	8.0700
20	9.7584	8.9155	8.0778
21	9.5020	8.6851	8.0449
22	9.2033	8.3783	7.8454
23	8.8853	8.0364	7.6970
24	8.7330	7.8477	7.6258

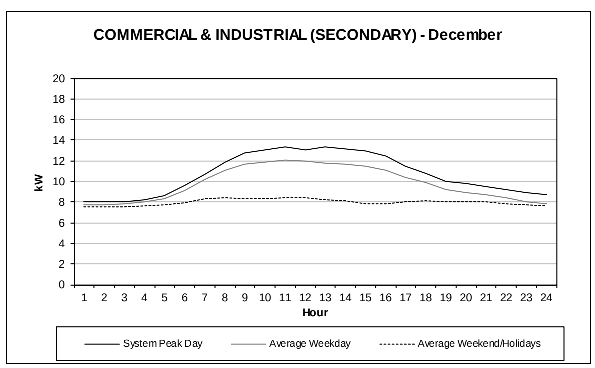


Figure 2.3-25 Commercial and Industrial (Primary) January Daily Load Profiles

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	578.5163	583.8778	571.6588
2	574.3872	577.4347	567.8235
3	570.3351	575.5048	565.5445
4	565.5616	580.0138	562.7108
5	569.5606	596.7601	567.3611
6	575.6986	623.7937	575.3297
7	586.1186	659.8851	586.8488
8	592.2909	686.2195	596.8260
9	597.7763	703.0958	601.8466
10	599.7324	707.7088	603.4108
11	598.1177	707.7328	602.1666
12	596.0205	705.1596	600.4675
13	595.2466	702.5879	597.8598
14	593.7861	701.3665	596.4650
15	591.5851	695.2203	592.9705
16	589.9183	687.0447	590.2803
17	589.2376	666.4442	586.1859
18	600.8005	656.5246	592.5900
19	597.1093	643.8861	589.6598
20	593.2301	633.7637	585.4264
21	587.6450	623.4307	579.4169
22	584.2570	614.6895	574.9018
23	578.9966	605.6453	568.9723
24	575.3287	596.8885	564.0813

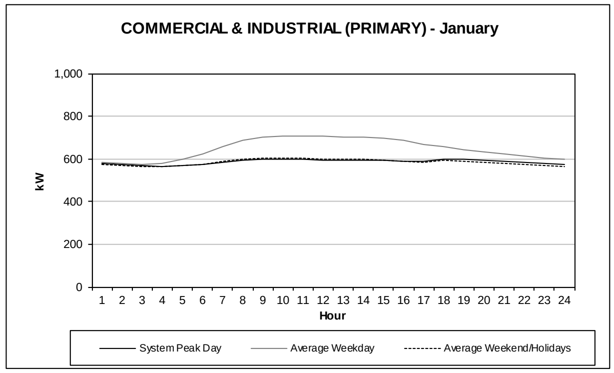


Figure 2.3-26 Commercial and Industrial (Primary) February Daily Load Profiles

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	580.5745	590.1400	574.0373
2	574.6012	583.4736	570.0368
3	575.7968	581.5499	568.1042
4	580.9384	586.5957	565.3036
5	598.8862	602.7677	570.1945
6	622.8077	629.5217	576.5475
7	660.0729	667.1942	586.1931
8	690.7496	691.4352	592.8776
9	719.8427	708.8494	600.5593
10	738.7343	715.8974	603.4957
11	750.3469	717.4168	603.3390
12	741.2947	715.0343	601.5340
13	738.0773	712.9542	600.5492
14	729.4929	713.3134	601.0220
15	721.0992	707.5405	597.7183
16	711.9073	697.4951	592.3106
17	688.6893	673.9465	586.1618
18	683.3855	662.8182	590.9469
19	671.2307	652.7742	593.2408
20	663.3129	642.7603	590.1008
21	654.7376	631.5222	584.1338
22	645.2812	622.0854	579.5635
23	634.7617	610.9391	572.8186
24	623.0952	601.5934	568.0030

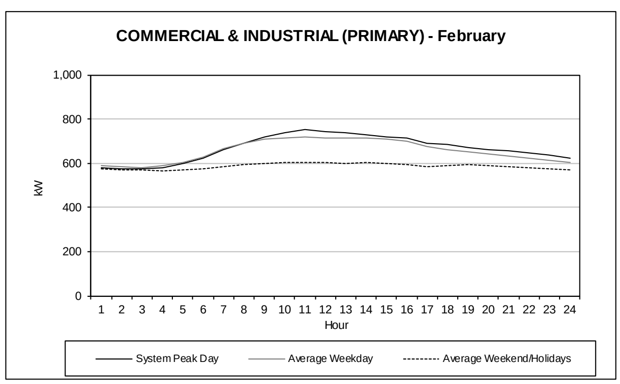


Figure 2.3-27 Commercial and Industrial (Primary) March Daily Load Profiles

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	587.2388	572.8116	567.8200
2	581.9820	566.3199	563.7928
3	581.2943	563.3837	560.8622
4	578.9668	568.4216	559.2118
5	581.1608	585.3458	564.5188
6	587.6245	613.6515	572.8920
7	596.0679	649.2525	583.1858
8	602.2299	672.1378	591.3835
9	613.8232	691.1313	597.3556
10	622.0396	701.5072	602.0736
11	620.7531	700.8297	600.2873
12	622.7158	694.6212	598.7512
13	621.8922	691.1024	594.8977
14	622.4322	690.7442	593.6337
15	621.4247	684.8074	591.5346
16	619.0313	675.4705	587.8288
17	609.2079	652.4321	579.5583
18	607.8297	638.0465	579.3034
19	615.8386	627.8199	581.1346
20	614.5683	622.0964	582.9402
21	608.7951	611.7688	580.2178
22	601.4693	601.8294	575.2296
23	595.3590	592.0036	569.3571
24	590.8583	583.0010	564.1450

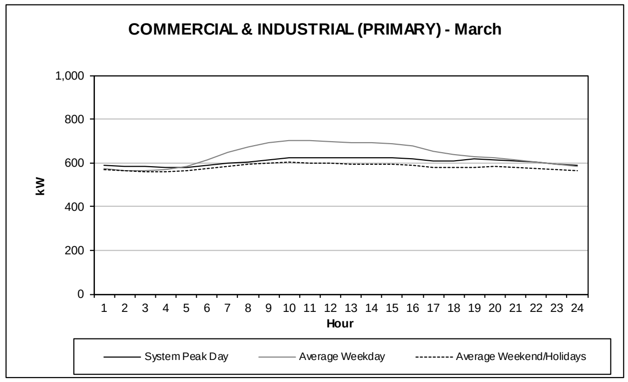


Figure 2.3-28 Commercial and Industrial (Primary) April Daily Load Profiles

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	577.9293	565.3924	557.7425
2	567.9745	556.7128	552.6154
3	560.7322	553.6898	549.1158
4	563.2503	558.3223	545.4247
5	576.0069	575.5405	550.0818
6	600.3961	604.5004	559.0250
7	647.9990	642.3485	566.2922
8	681.9675	670.8709	574.1735
9	700.8035	690.1565	582.0827
10	706.9067	698.7161	590.3338
11	704.3492	705.1298	595.5665
12	701.9157	708.2165	597.0532
13	700.7679	709.0224	596.9049
14	699.1847	711.9876	596.3888
15	684.7715	707.0361	594.9472
16	663.9217	700.6080	594.0622
17	636.6133	676.8120	587.5309
18	624.4764	656.6991	584.6825
19	608.2766	640.4957	579.9203
20	602.2557	629.9870	577.2096
21	594.9776	621.3500	575.3389
22	585.4547	605.9200	566.2360
23	575.2913	592.1490	558.1123
24	565.4777	581.0495	550.4669

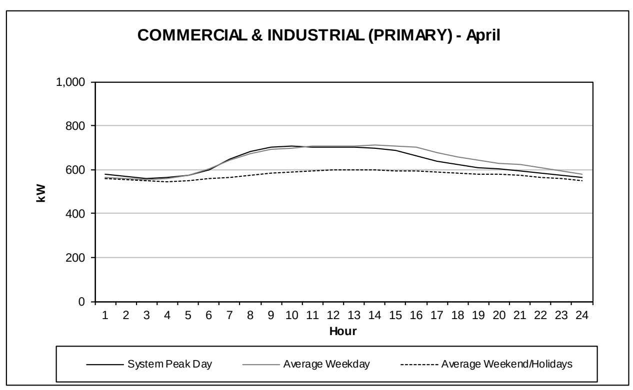


Figure 2.3-29 Commercial and Industrial (Primary) May Daily Load Profiles

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	583.1185	564.5706	546.7417
2	572.4500	555.7131	540.2781
3	565.1059	552.0914	536.4257
4	565.9024	555.3209	533.9461
5	578.2647	572.3739	539.9117
6	603.3320	601.0284	548.2470
7	647.1522	634.7014	551.5275
8	678.2546	662.6794	558.8722
9	710.5213	680.4174	563.5806
10	732.6607	691.0365	570.4344
11	748.5273	695.9836	574.6190
12	764.2499	699.9432	578.7466
13	763.0652	700.2145	581.6073
14	759.8293	702.2138	584.8231
15	755.5260	697.9603	585.8571
16	745.2877	690.3462	584.7371
17	730.5538	668.5328	582.0576
18	706.6917	648.5822	575.4302
19	682.2228	630.5015	569.8075
20	665.0297	618.3361	566.1687
21	655.6495	612.9988	564.7406
22	639.9206	600.1188	558.1238
23	621.5964	587.9031	549.9231
24	609.8653	577.4935	543.2224

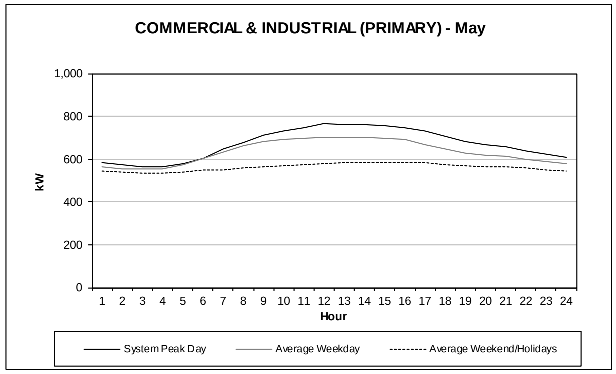


Figure 2.3-30 Commercial and Industrial (Primary) June Daily Load Profiles

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	628.1454	591.9083	579.5560
2	616.1495	582.6993	572.0844
3	605.2871	577.1849	565.9712
4	604.0947	578.6923	562.2085
5	617.4570	593.7351	566.7338
6	646.4589	622.6545	573.6415
7	685.1604	657.3875	582.2802
8	722.7721	691.3234	596.2913
9	751.4725	715.7802	603.8405
10	768.6117	732.8205	613.7485
11	772.7988	739.8277	619.7475
12	776.2599	747.7165	624.7905
13	776.8465	753.4878	628.5534
14	787.7160	759.0507	631.3594
15	780.8348	753.5181	625.7279
16	775.2903	746.2176	620.5294
17	755.7900	725.0943	617.6106
18	738.5203	702.3684	612.2394
19	719.8401	683.1618	605.0981
20	700.1409	667.8760	598.2886
21	690.1010	655.6576	597.0389
22	673.9756	641.5108	590.3809
23	656.5895	625.8439	581.1074
24	640.7033	612.0871	572.0991

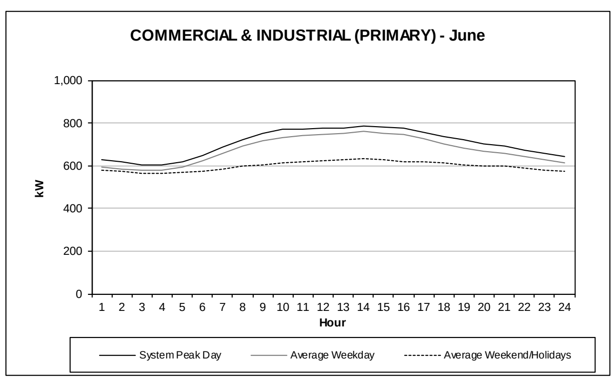


Figure 2.3-31 Commercial and Industrial (Primary) July Daily Load Profiles

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	651.9310	628.0643	614.6773
2	638.8434	618.1154	606.1067
3	623.4114	610.9635	598.1006
4	621.1906	613.0007	593.6028
5	641.7373	629.9926	597.7102
6	674.7497	660.7075	606.9929
7	709.7344	697.9306	615.2869
8	748.6566	735.9066	631.9965
9	772.3910	762.0846	642.7615
10	785.8878	778.0199	653.8774
11	793.0442	786.3623	661.8214
12	796.9763	794.3564	667.2771
13	805.2555	799.9654	673.1238
14	813.0680	804.7456	675.6570
15	807.5152	800.0438	677.0793
16	802.1025	793.4037	674.3717
17	783.4364	775.5739	669.6791
18	764.0684	751.4192	664.8818
19	746.5181	729.4854	653.5857
20	728.2633	712.3184	642.8406
21	711.3594	698.4453	636.9023
22	693.6123	683.5278	629.8486
23	673.6218	664.9024	618.7105
24	658.9400	650.6345	607.5626

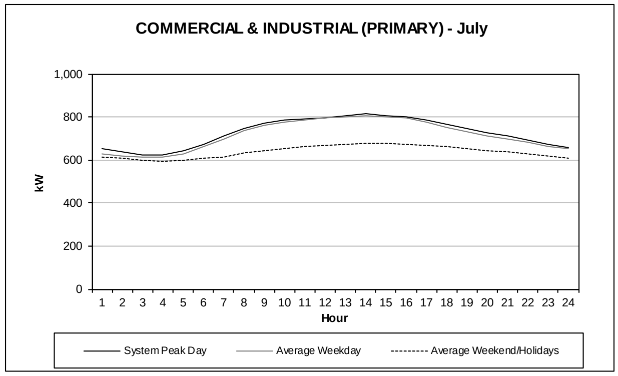


Figure 2.3-32 Commercial and Industrial (Primary) August Daily Load Profiles

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	660.2548	642.5704	632.1855
2	649.0683	631.7597	622.3229
3	640.1584	625.5600	615.7708
4	640.7615	627.2816	611.3439
5	658.9751	644.2109	615.8090
6	687.0045	677.4932	625.3453
7	725.2093	713.5546	635.0745
8	757.0925	746.5242	647.2945
9	781.9218	770.7075	657.2863
10	789.9260	787.4165	669.9427
11	811.7516	798.3285	679.9236
12	833.3964	809.1800	686.2384
13	840.3717	815.6613	689.3339
14	842.5606	821.4229	693.5738
15	844.9170	818.6983	690.7489
16	838.5277	811.0339	689.1083
17	814.8040	788.2581	684.9572
18	792.8517	765.7730	683.4393
19	768.2968	743.4817	677.2892
20	747.9697	724.4763	669.2835
21	736.9652	712.5240	662.5655
22	717.3972	693.5037	650.3726
23	694.4394	674.1673	638.0890
24	680.3802	659.1351	627.8976

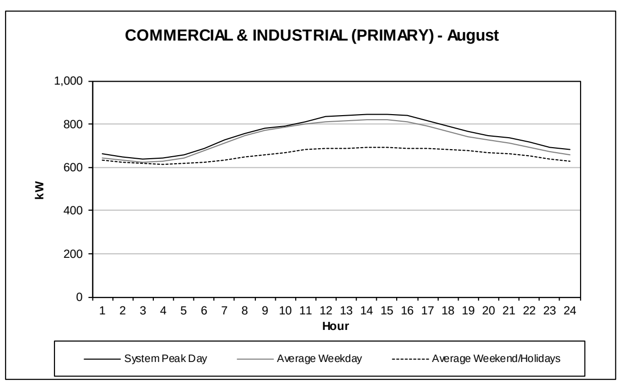


Figure 2.3-33 Commercial and Industrial (Primary) September Daily Load Profiles

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	605.3590	618.3871	602.7732
2	596.6577	608.6660	593.7734
3	593.7618	602.4598	587.0915
4	593.9306	604.2222	581.8840
5	602.4561	619.5811	585.2308
6	614.9191	651.2642	595.9893
7	625.8673	688.8310	607.7803
8	629.5956	715.8852	614.4909
9	639.7978	739.2389	621.6043
10	661.0068	759.4450	635.2128
11	674.7956	772.7219	646.2321
12	684.4468	783.8413	655.4135
13	691.9192	790.9251	661.4253
14	691.8309	797.9863	666.3137
15	692.4722	798.6389	668.2652
16	693.2083	792.7804	669.9778
17	697.5940	770.9671	668.0315
18	697.0172	746.4249	664.0673
19	690.5523	723.6576	656.1843
20	679.4284	706.0903	648.4920
21	669.1845	690.2756	637.2068
22	651.2872	672.6769	624.1410
23	631.1512	651.7891	611.5991
24	617.8714	637.0825	599.4047

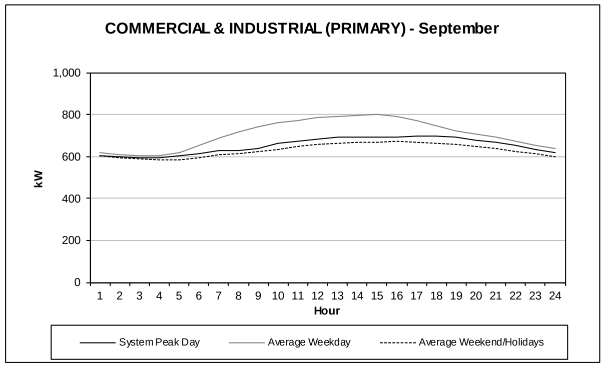


Figure 2.3-34 Commercial and Industrial (Primary) October Daily Load Profiles

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	635.0963	601.9749	581.5693
2	628.1763	594.5122	577.0945
3	622.4901	591.0219	575.3145
4	628.5862	595.1360	573.8640
5	645.8191	611.7886	579.8959
6	673.4272	641.0458	589.9062
7	703.6840	676.0680	601.2421
8	729.8481	701.2144	608.7975
9	740.2195	712.4935	606.7141
10	746.8022	716.7788	605.1524
11	748.2380	717.5943	603.7502
12	747.5034	720.7246	603.0894
13	743.9367	719.8611	601.9866
14	739.8113	721.5659	603.7043
15	729.0948	719.1450	602.4036
16	720.4856	713.9113	603.2155
17	708.5418	696.8548	604.4431
18	705.6522	680.5711	606.3065
19	702.2635	669.2228	607.4985
20	692.8758	658.2781	604.4919
21	683.8249	648.2461	598.8128
22	677.8906	637.3627	594.1579
23	667.7780	623.6644	588.1439
24	654.8666	613.2542	582.4400

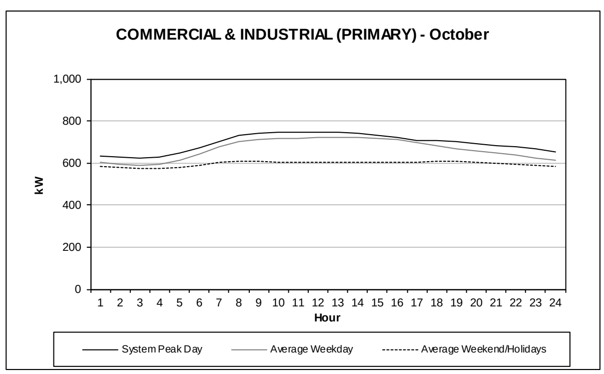


Figure 2.3-35 Commercial and Industrial (Primary) November Daily Load Profiles

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	629.4765	610.6504	598.3078
2	623.8051	604.3517	593.4635
3	622.2365	602.0824	590.0552
4	625.5364	607.4629	588.2673
5	640.2761	624.0528	594.1212
6	659.7845	652.0883	602.7266
7	688.2741	686.1584	610.5982
8	703.8618	707.9239	616.5448
9	704.9265	721.1115	618.4595
10	709.4293	722.4236	614.8316
11	702.2573	720.6779	612.3123
12	704.1401	719.8889	610.6631
13	700.3554	718.5030	607.7090
14	698.3764	717.8183	607.2239
15	696.0488	715.0665	607.0909
16	692.5345	708.5503	606.9979
17	686.1354	691.8305	605.1463
18	679.2328	679.2495	609.1379
19	662.2590	667.8769	606.3625
20	649.1187	657.7728	601.6230
21	641.5891	649.6769	598.7365
22	634.0106	643.5418	597.1304
23	622.1458	633.3074	592.3538
24	613.6760	624.5551	587.9400

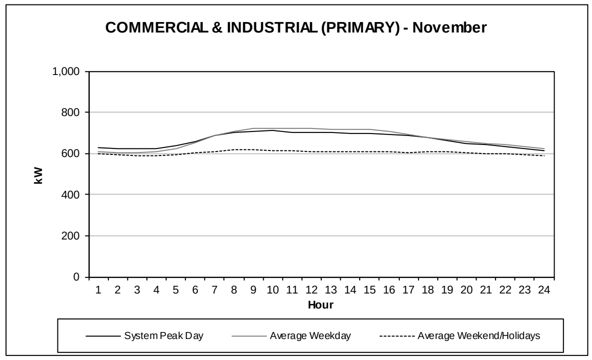


Figure 2.3-36 Commercial and Industrial (Primary) December Daily Load Profiles

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	575.0270	594.2694	575.6189
2	574.0256	589.2479	571.2588
3	576.2041	587.0876	569.0357
4	580.7323	592.3555	567.3351
5	599.9489	609.6282	574.1102
6	631.5872	635.5651	582.1622
7	663.4242	669.4300	592.7920
8	688.7425	695.0645	604.5737
9	710.8047	709.8757	611.7009
10	717.4485	712.1254	611.2357
11	709.8878	708.5137	609.9065
12	716.2746	705.0414	606.6834
13	715.6959	700.2676	605.9250
14	715.3128	701.0626	608.8270
15	706.6302	696.9525	608.5464
16	708.2385	690.4334	607.8728
17	689.2190	671.9183	602.0594
18	677.1887	660.4826	603.7400
19	664.8459	649.4101	600.2711
20	650.1610	636.8467	593.2920
21	641.3290	627.7647	587.0503
22	638.2073	620.5521	583.6888
23	628.3030	610.4785	578.3331
24	619.7949	602.1304	572.9256

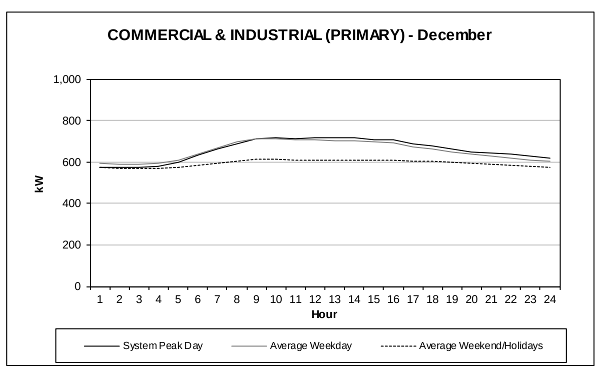


Figure 2.3-37 Commercial and Industrial (Transmission) January Daily Load Profiles

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	5658.9303	5733.2543	5446.8450
2	4568.7139	5764.4551	5431.8009
3	4430.9307	5700.7089	5425.3421
4	4436.2676	5730.2304	5214.6925
5	4420.8690	5597.0508	5099.6547
6	5048.6441	5531.6337	5100.1889
7	5351.7143	5540.6573	5093.1251
8	5277.8596	5559.1475	4993.5301
9	4667.1979	5789.0082	4939.3952
10	5214.8347	5759.6717	4997.9942
11	4181.4030	5675.6569	4691.0626
12	4163.7722	5612.2547	4479.6739
13	5288.5934	5637.2977	4990.7426
14	5255.6293	5598.1233	5037.5860
15	5461.8560	5613.5177	5105.2396
16	5705.0178	5830.9078	5067.4939
17	5723.2640	5872.3637	4956.5085
18	5555.8663	5833.8870	4756.0316
19	5626.6857	5812.1769	4871.2930
20	5536.8076	5765.0531	4816.2415
21	5512.8994	5851.4674	4961.6688
22	5468.4129	5853.3964	5029.8713
23	5802.8121	5909.6012	5148.8027
24	5711.8240	5866.6885	4989.0567

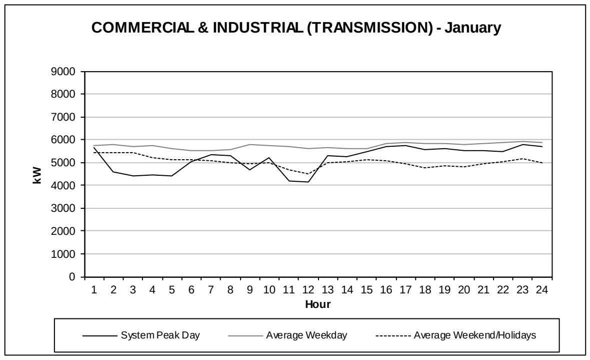


Figure 2.3-38 Commercial and Industrial (Transmission) February Daily Load Profiles

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	6012.4521	5471.7500	6481.4913
2	6013.4450	5593.8069	6497.8697
3	6038.1640	5620.0055	6577.4558
4	5964.6775	5593.9430	6520.0666
5	5847.6629	5342.7108	5140.6230
6	5651.4257	5378.0733	5349.0239
7	5623.0491	5135.8924	5278.0987
8	5641.7861	5040.9025	5051.4432
9	5684.1777	5179.4931	4957.8064
10	5730.7383	5006.2929	4792.7100
11	5748.0764	4932.7453	5030.9633
12	5634.0811	5009.0898	5185.7853
13	5638.5006	5136.5578	5127.5596
14	5792.2718	5136.1469	5155.7264
15	5838.0955	5200.5927	5246.9533
16	5900.2464	5164.3478	6037.8058
17	6034.6049	5029.4653	6137.3050
18	5929.8993	5031.0399	6371.6684
19	5913.5259	5192.9978	6408.4603
20	5830.2464	5159.9055	6641.8884
21	5961.2499	5155.0535	6658.6806
22	6111.5180	5320.5351	6364.4257
23	6099.2395	5264.4221	6451.0219
24	6087.6421	5236.5333	6569.6287

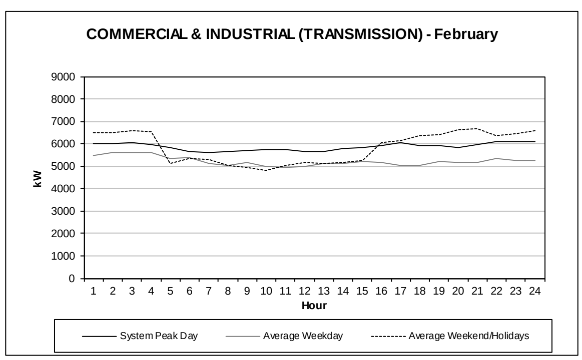


Figure 2.3-39 Commercial and Industrial (Transmission) March Daily Load Profiles

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	5446.8534	5283.4866	4905.4957
2	5443.3045	5323.3154	4670.0822
3	5558.6549	5196.9410	4804.4624
4	5557.9182	5221.4519	5129.1331
5	5483.7257	5296.8201	4883.5290
6	5518.1675	5125.7285	4866.2866
7	5550.9546	5103.5216	4928.8942
8	5534.0384	4836.5525	4830.4064
9	5532.6853	4645.6714	4949.4722
10	5471.2607	4628.9632	4710.4363
11	5597.2237	4579.2759	4868.2059
12	5549.2561	4642.1649	4846.7048
13	5543.3050	4914.1337	4907.0852
14	5491.4938	5038.6305	4967.8487
15	5667.9511	4793.4124	4924.1044
16	5631.4293	4859.5752	4601.1644
17	5754.2660	4859.0087	4880.5030
18	5604.7800	4742.8562	5007.0205
19	5607.3118	4908.6573	4811.5158
20	5535.8625	4946.5451	4897.7588
21	5749.3623	4896.1436	4115.1010
22	5749.7021	4710.1033	3915.0337
23	5694.4062	4784.4109	4092.9869
24	5705.4263	5128.8443	4861.1484

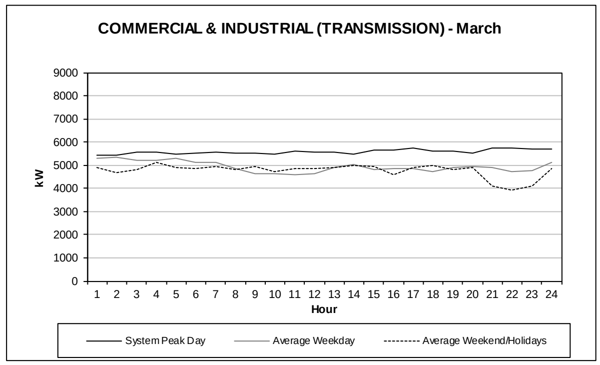


Figure 2.3-40 Commercial and Industrial (Transmission) April Daily Load Profiles

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8428.4188	7553.1035	7402.0356
2	7545.5345	7440.3551	7080.8074
3	7615.3355	7282.0347	6997.7646
4	8440.1265	7198.0489	7085.1825
5	7373.5654	7187.1929	7153.4301
6	7038.7901	7016.6011	7043.9414
7	7023.3854	7001.9582	6657.4458
8	6989.3438	6960.4653	6471.3996
9	6971.4223	7069.1257	6298.3471
10	6982.3987	7018.8452	6299.7616
11	7143.3728	6926.8469	6450.6941
12	7050.3825	6963.0165	6566.3376
13	7182.6734	7079.2096	6526.4891
14	7015.9475	7175.7903	6466.5860
15	7166.0317	7223.4986	6675.3307
16	7080.0343	7220.9222	6631.3203
17	7406.1361	7496.0206	6852.0364
18	7486.0358	7342.8460	6997.5818
19	7508.8017	7445.9778	7098.6370
20	8473.5579	7548.4528	6979.3586
21	8355.5305	7609.8528	7137.9075
22	8463.0275	7751.7712	7144.5185
23	8358.7655	7663.2686	7129.9643
24	8469.8580	7690.4603	6794.1775

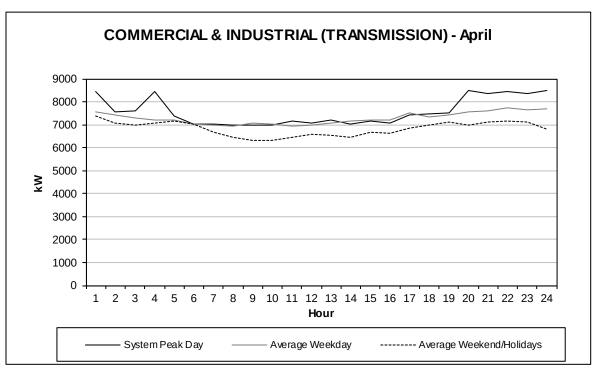


Figure 2.3-41 Commercial and Industrial (Transmission) May Daily Load Profiles

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7324.5044	6843.2295	6622.2468
2	7310.9406	6745.5008	6545.6214
3	7478.3556	6693.6139	6531.4838
4	7239.7095	6777.1551	6653.5847
5	7677.8099	6518.0116	6512.0976
6	7140.7838	6419.8919	6384.1695
7	7517.7358	6362.3851	6100.4315
8	7359.3253	6270.7626	5950.8344
9	7300.0049	6184.9164	5413.6248
10	7613.9330	6202.7587	5450.0727
11	7690.8842	6224.0966	5699.4661
12	7763.5317	6401.8540	5549.9838
13	7647.6231	6511.5407	5810.0840
14	7762.9412	6499.0976	5690.1985
15	6698.6785	6516.0377	5863.4629
16	5730.0014	6468.4719	5708.6047
17	5022.3183	6485.1389	5582.3651
18	5952.0896	6433.9754	5484.7137
19	5989.9473	6488.1146	5770.6528
20	6160.6391	6541.3466	6006.7920
21	6323.5397	6614.3621	6029.7020
22	6890.2889	6828.5518	5971.8352
23	7602.7104	6675.3585	5930.6863
24	7640.4018	6818.3108	6146.5520

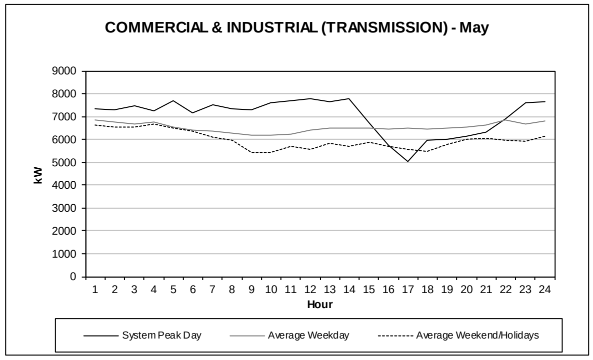


Figure 2.3-42 Commercial and Industrial (Transmission) June Daily Load Profiles

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	6620.1030	6000.0720	5694.3875
2	6606.9884	6286.6541	5834.7416
3	6612.7098	6258.4400	5768.8978
4	6790.0289	6253.9011	5691.8558
5	6539.0015	6077.1692	5743.3218
6	6349.6429	5978.6633	5498.3094
7	6317.4898	5938.7956	5336.6175
8	6101.0378	5775.2012	5296.6744
9	6226.9188	5852.0652	5131.3082
10	6105.9888	5696.1418	5121.3349
11	6387.8658	5897.4915	5078.6985
12	6338.3525	6001.6931	4970.5520
13	6422.3802	5929.3286	5032.6673
14	6459.9268	5871.4459	4921.1229
15	6039.8399	5816.6692	5017.0946
16	6397.1761	5824.7635	4975.8633
17	6229.8452	5786.0949	4996.2090
18	5965.1667	5820.6997	5010.2316
19	5984.9701	5829.4479	5155.7122
20	6055.1635	5789.5831	5043.4814
21	6194.2808	5846.9668	5096.2657
22	6135.1669	5811.9763	5184.2409
23	6757.8597	5797.5868	5283.5967
24	6209.4704	6037.7736	5218.5186

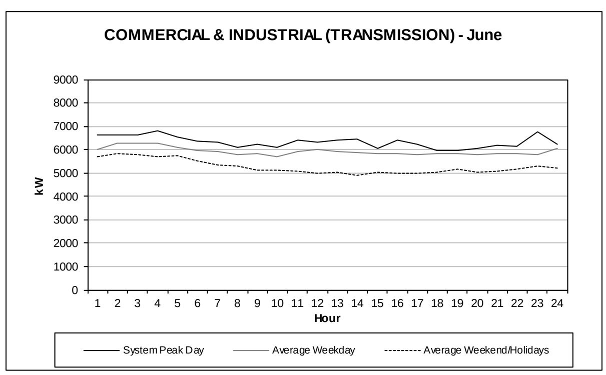


Figure 2.3-43 Commercial and Industrial (Transmission) July Daily Load Profiles

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	6294.1172	6287.2665	6010.1859
2	6772.6693	6294.4371	6086.6775
3	6761.2814	6308.6476	5909.5229
4	6923.1796	6416.8675	5993.5626
5	6492.3081	6325.9485	5967.5923
6	6065.2084	6226.0435	5885.1881
7	6028.0690	5980.5223	5703.5224
8	5582.7279	5855.1617	5403.5788
9	4986.0239	5711.4355	4991.0852
10	5958.5970	5720.5866	5164.3052
11	5619.6355	5729.3751	5104.1321
12	5844.3249	5679.4329	5187.5286
13	5482.3360	5762.8449	5115.4500
14	5588.6987	5813.8266	5078.1886
15	5689.7837	5788.3535	4941.3355
16	5707.4593	5819.2591	4956.3610
17	5617.9030	5919.4773	4989.0162
18	4770.3743	5782.7344	5179.5435
19	5601.2392	5776.3842	5086.5630
20	5880.7037	5742.4312	5069.2398
21	5540.6386	5812.6318	5377.5114
22	5353.5857	5947.6656	5459.3160
23	5866.0554	6282.4197	5608.0495
24	5617.1718	6164.6997	5495.1141

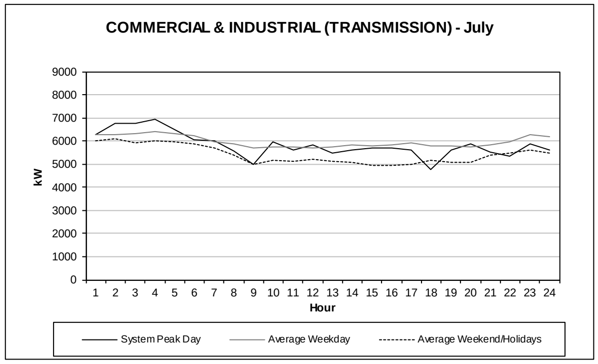


Figure 2.3-44 Commercial and Industrial (Transmission) August Daily Load Profiles

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	6891.7745	6703.9605	6342.1688
2	7532.1307	6868.5633	6350.4676
3	7323.8331	6822.9329	6303.4027
4	7892.4899	6822.1851	6333.5289
5	8158.5650	6687.4001	6336.8277
6	7472.6062	6528.9017	6426.5519
7	6974.8749	6501.7531	6305.7627
8	6269.6922	6312.7946	5934.4562
9	6055.6192	6109.8612	5656.0253
10	6142.5048	6149.7817	5705.4671
11	5864.5445	5829.1407	5420.1672
12	6056.7381	5832.0809	5589.3547
13	5506.0420	5966.6970	5197.9522
14	4896.7480	5886.6350	5084.4624
15	4816.8258	5811.7121	5052.2236
16	5917.4172	5892.3851	5063.1151
17	5095.6180	5820.9306	5196.0597
18	5224.3550	5695.1858	5346.6459
19	5302.2030	5769.2398	5373.5630
20	6491.8254	5915.6933	5600.3058
21	6041.2692	5891.8825	5780.5153
22	4987.0002	5870.7472	6072.9131
23	6960.0951	6288.3230	6380.7329
24	7969.5068	6668.9616	6412.9505

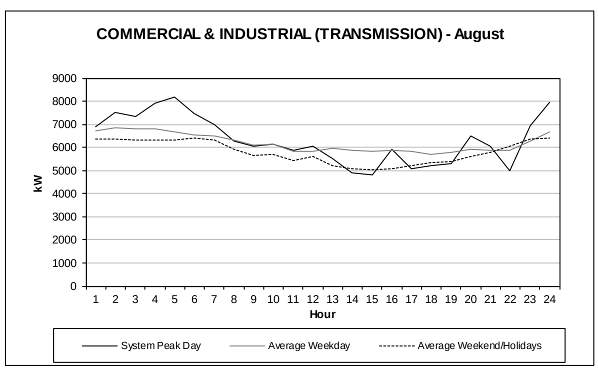


Figure 2.3-45 Commercial and Industrial (Transmission) September Daily Load Profiles

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	5957.9755	6029.4379	5770.0026
2	5858.2231	6280.0564	5760.6378
3	5517.2608	6323.4870	5799.5249
4	5488.6323	6287.5465	5781.4694
5	5489.6722	6248.8850	5715.6452
6	5701.0368	6127.9955	5490.5883
7	5834.9724	6034.7902	5462.4002
8	5762.0085	6025.1158	5214.2932
9	5678.5400	5804.5859	5050.1655
10	5442.1336	5776.5486	4959.2690
11	5243.7959	5905.0413	4725.5662
12	4346.0449	5966.3572	4617.7561
13	3976.1186	5943.4313	4701.1403
14	4013.0187	5906.4025	4721.1583
15	4030.5315	5858.1638	4677.4906
16	3987.0696	5860.6522	4755.6957
17	3964.1041	5742.5729	4647.2962
18	3938.8672	5599.2725	4858.4548
19	3903.2108	5726.0314	4904.6728
20	3973.4906	5638.5186	4956.3436
21	3946.7217	5463.4986	5060.5793
22	3947.6839	5693.0006	5093.6406
23	4205.9517	5872.1769	5074.1318
24	4199.2160	5998.2892	5288.5876

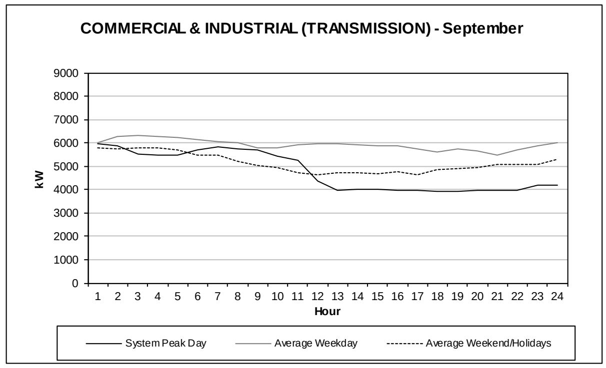


Figure 2.3-46 Commercial and Industrial (Transmission) October Daily Load Profiles

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	6365.0332	6412.1926	6353.8354
2	6184.0581	6390.9049	6586.1320
3	6299.8202	6307.9332	6462.0372
4	6022.4685	6282.8826	6432.8658
5	4883.5779	6232.9919	6494.4271
6	4772.2176	6146.6368	6424.5478
7	4658.1293	6448.2930	6210.9363
8	4634.3924	6358.3866	6096.5255
9	4722.9201	6238.6936	5939.8447
10	5132.3087	6157.4400	5978.1210
11	5221.1325	6235.1282	5894.2990
12	5258.5357	6256.4602	5766.4302
13	5562.9131	6284.5236	5728.0300
14	5364.4504	6442.9609	5616.1510
15	5259.0707	6550.4281	5730.5416
16	6117.1644	6514.3369	5827.2827
17	5984.1022	6494.1325	5684.9044
18	6322.9841	6671.2059	5846.0709
19	5998.5653	6657.8576	6139.7032
20	5069.2910	6700.7247	5936.1849
21	5428.8981	6606.2523	5821.7960
22	5937.2334	6526.7620	5830.7253
23	6115.6992	6687.5107	5863.9803
24	6202.0356	6656.6529	5671.0434

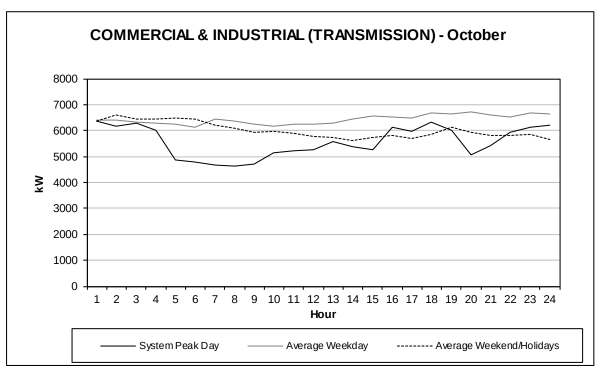


Figure 2.3-47 Commercial and Industrial (Transmission) November Daily Load Profiles

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	5451.2310	6267.6988	6149.5645
2	5316.3970	6379.4978	6099.1438
3	5253.7248	6311.3816	6094.2390
4	5258.4617	6162.3208	6149.0600
5	5525.2488	6039.7637	6017.3808
6	6034.4753	6170.7342	5888.8957
7	5382.6023	6126.6561	6018.7397
8	5666.9325	5907.3077	5760.0786
9	5523.8197	5783.9269	5683.5840
10	5536.1911	5663.0634	5620.0555
11	5390.4804	5768.5544	5513.6341
12	5487.4529	5809.3542	5602.8841
13	5553.9651	5978.7111	5477.8125
14	5544.6251	6102.2083	5449.0796
15	5917.2173	6278.3226	5595.3347
16	5778.7687	6235.1501	5881.8074
17	5873.2537	6475.5841	5919.6624
18	5937.3298	6347.3452	5636.9305
19	5402.4013	6252.4386	5739.4645
20	5506.1288	6123.1011	5698.6993
21	5475.2321	6294.3228	5921.1735
22	5114.3823	6295.0099	5934.1672
23	5417.1634	6360.8639	5754.6508
24	6182.6443	6299.8331	5762.6910

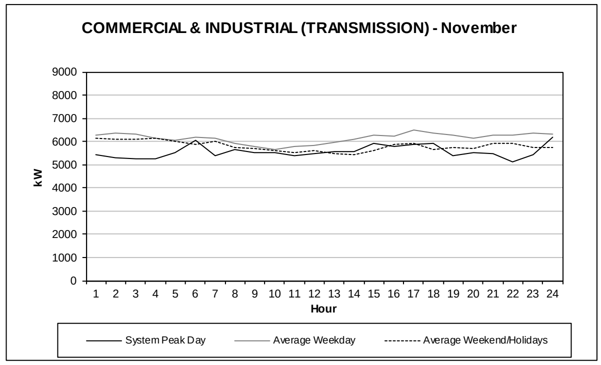


Figure 2.3-48 Commercial and Industrial (Transmission) December Daily Load Profiles

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	4957.3658	5735.3062	5384.5355
2	5661.5006	5948.2171	5392.5900
3	5414.0526	5798.6375	5116.5754
4	5554.2579	5807.4965	5339.5305
5	5455.7024	5809.0802	5377.5397
6	5800.9795	5710.4887	5415.9078
7	6113.3863	5660.6072	5512.4122
8	5924.4471	5599.7097	5536.3077
9	6756.7378	5520.2938	5303.1209
10	6588.0344	5463.9685	5131.2492
11	6580.9837	5580.4710	4989.8881
12	6524.4955	5488.1214	5360.4842
13	6521.2786	5282.8635	5311.4928
14	6609.4859	5499.8943	5157.9012
15	6216.4165	5707.3275	4938.9134
16	6359.5555	5909.0761	5219.5531
17	6379.3092	5909.6437	5328.8802
18	6504.4484	5744.8202	5070.1886
19	6572.8007	5881.1403	5151.8161
20	6472.2737	5776.4966	5182.0405
21	6203.7369	5989.6557	5197.8551
22	6283.9893	5900.1665	5153.9153
23	6652.3063	5945.4798	5424.4596
24	6570.3011	5767.1387	5237.9989

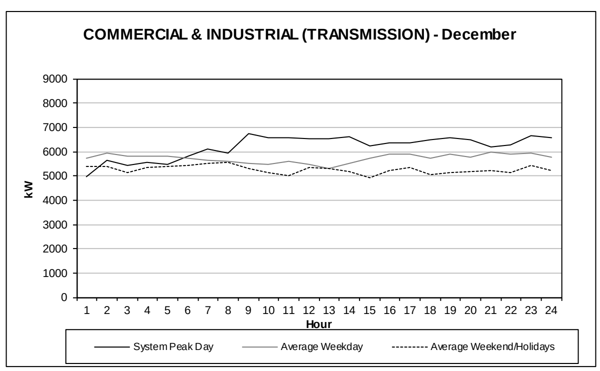


Figure 2.3-49 FERC January Daily Load Profiles

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	80849	67623	68768
2	78122	66682	67091
3	76836	66576	66617
4	76008	67099	66812
5	76371	69007	67629
6	77740	73002	69386
7	80536	79427	72981
8	84012	83116	77262
9	86443	82621	79639
10	87443	81163	79751
11	87713	79214	78725
12	88269	77180	77496
13	87045	74940	75935
14	85327	73540	74735
15	84576	73133	74587
16	85618	73500	75123
17	92254	77455	78968
18	103040	86095	87190
19	103917	88583	88650
20	101943	87192	86661
21	98940	84937	84536
22	93960	80419	80800
23	86988	74331	75012
24	81098	69645	70246

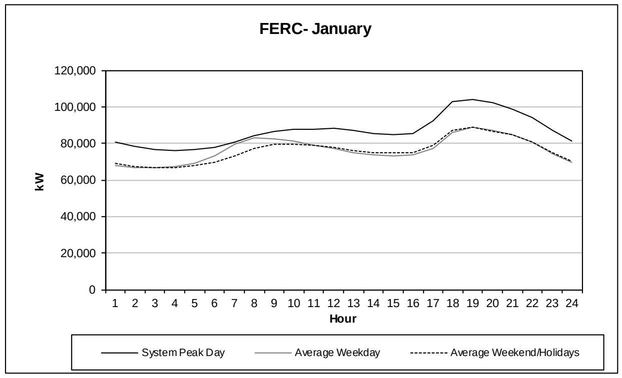


Figure 2.3-50 FERC February Daily Load Profiles

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	61305	66578	67253
2	60527	65772	66187
3	60530	65751	65675
4	60871	66224	65723
5	62947	68159	66993
6	67437	72454	69086
7	74813	78937	72645
8	78922	81813	76661
9	80443	80534	78464
10	81425	78976	78863
11	81357	76966	77334
12	81547	74945	75376
13	81008	73090	74118
14	79418	71893	73215
15	78774	71598	73053
16	79844	72035	73610
17	82655	74799	76241
18	89594	81544	82630
19	93587	86227	86422
20	91914	85266	84971
21	89249	83201	83103
22	84067	78887	79332
23	78418	73219	73914
24	74025	68686	69217

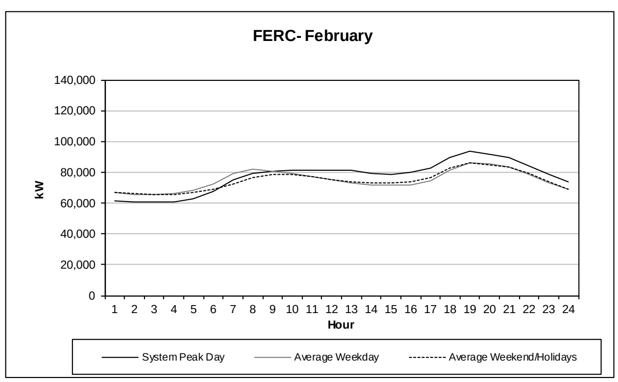


Figure 2.3-51 FERC March Daily Load Profiles

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	68711	60099	62493
2	67347	59012	61156
3	66866	58871	60876
4	66738	59445	61073
5	67763	61081	61953
6	69606	65034	63737
7	73318	71215	67327
8	77904	74613	71320
9	81291	74177	73233
10	83293	72792	73618
11	82129	71107	72660
12	81889	69416	71302
13	82044	67571	69902
14	83229	66492	68870
15	84879	66053	68542
16	85022	66036	68342
17	86867	67037	69433
18	90129	70422	72424
19	94446	74097	75553
20	92759	76697	77780
21	89817	76304	77687
22	84466	72722	74399
23	77994	67349	69215
24	72482	62720	64652

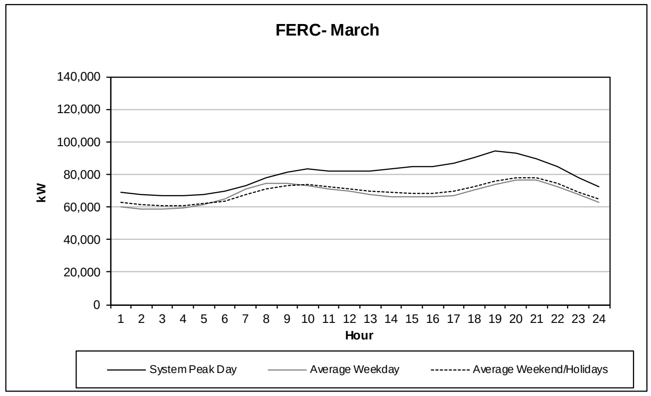


Figure 2.3-52 FERC April Daily Load Profiles

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	47346	49877	50028
2	46848	49052	48558
3	46377	49027	48032
4	46143	49449	48157
5	47830	51097	48987
6	52269	55170	50999
7	58719	60892	53456
8	62672	63031	55985
9	64420	62313	58097
10	66173	61132	58387
11	66942	59819	57788
12	66601	58412	57032
13	66358	57063	56212
14	65374	56561	55615
15	65673	56253	55432
16	66193	55733	55487
17	68235	56400	55993
18	71807	58901	57967
19	72858	60943	59447
20	74020	63164	61282
21	74443	64678	63181
22	70910	61746	60606
23	65064	56652	55980
24	60855	52116	51783

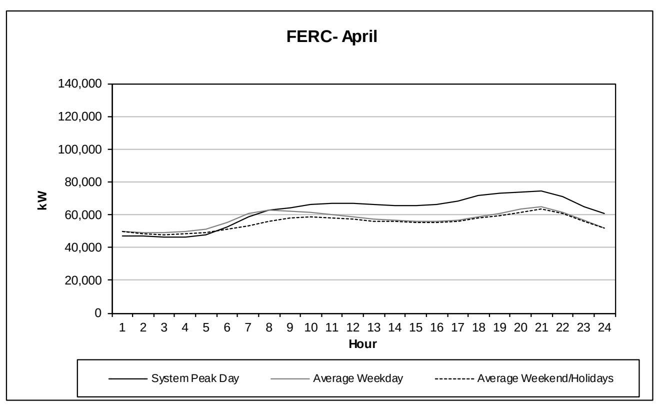


Figure 2.3-53 FERC May Daily Load Profiles

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	44966	47812	46699
2	43398	46569	45373
3	42131	46087	44848
4	42404	46364	44963
5	43561	47886	45793
6	46883	51339	47518
7	51596	55781	49387
8	53312	57632	50937
9	53412	57468	52374
10	53481	56873	52631
11	54134	56203	51994
12	54920	55697	51463
13	55730	55269	51305
14	56115	55113	50919
15	56075	55099	50975
16	57026	55302	51786
17	59160	56440	53035
18	61479	58364	55008
19	62484	59569	56319
20	62943	60261	56963
21	64332	62102	58984
22	61554	60157	57638
23	55314	55149	53110
24	49610	50670	48765

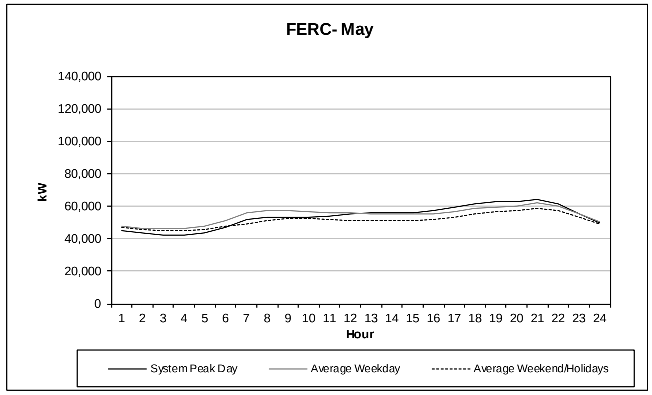


Figure 2.3-54 FERC June Daily Load Profiles

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	52736	46509	48477
2	48714	44437	45969
3	46187	43340	44476
4	44909	43079	43739
5	45402	44109	43890
6	47764	46428	44884
7	50944	49693	46682
8	54289	52446	49695
9	58783	54293	53493
10	63189	55493	56121
11	67243	56735	57565
12	71181	57877	58999
13	74660	59318	60475
14	79182	60806	61813
15	83266	62018	62667
16	87104	63178	62819
17	88392	64125	63174
18	88956	66021	64399
19	88728	66757	64328
20	86691	65802	63504
21	82873	65515	63630
22	79363	63982	62528
23	70536	57613	56979
24	61935	51301	51197

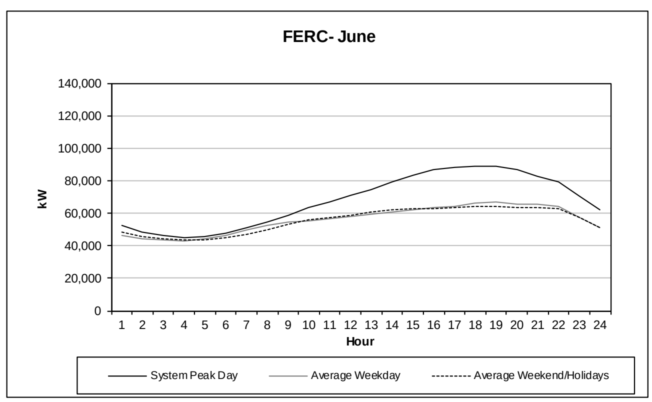


Figure 2.3-55 FERC July Daily Load Profiles

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	59708	53320	54154
2	54529	49827	50417
3	51033	47721	47918
4	48827	46623	46434
5	48419	46812	45903
6	49826	48656	46550
7	52920	52049	48070
8	57733	56264	51743
9	63374	60495	57089
10	69107	64604	62339
11	74667	68687	66562
12	80145	72766	70284
13	85272	76529	73985
14	90693	80253	77436
15	95747	83279	80846
16	100179	85676	82323
17	103378	87430	83817
18	105428	88851	83848
19	105306	88013	81742
20	102185	84479	77975
21	96647	80961	75048
22	91154	77172	72136
23	81499	68772	65260
24	71725	60279	57550

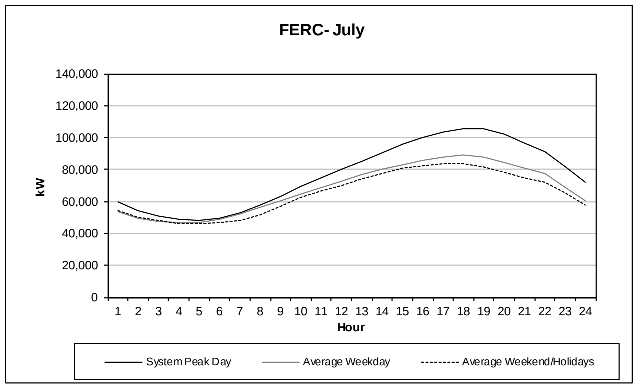


Figure 2.3-56 FERC August Daily Load Profiles

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	55447	53234	53782
2	51463	49913	50041
3	48763	47890	47765
4	47179	46782	46371
5	46643	46967	45948
6	49297	49449	46639
7	54091	53778	48207
8	57123	57094	51347
9	60085	59856	55714
10	64171	62841	60615
11	68646	66226	65318
12	73939	70114	69927
13	79319	74203	74001
14	85033	78233	77634
15	90836	81498	81069
16	95456	84242	84066
17	98960	86483	86456
18	102826	88235	87811
19	100355	87481	87132
20	95023	83477	83729
21	90316	80419	80894
22	82398	74861	75518
23	71968	66395	67169
24	62750	58503	59380

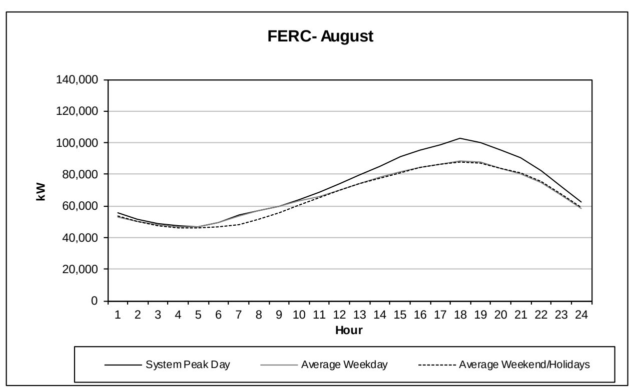


Figure 2.3-57 September Daily Load Profiles

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	56562	47403	48482
2	52415	45048	45834
3	49580	43664	44224
4	47818	43270	43409
5	47435	43998	43466
6	48160	47005	44583
7	49192	52626	46284
8	51679	55232	49057
9	56284	55560	52304
10	63331	56412	54966
11	70819	57855	57292
12	78188	59408	59731
13	84389	61384	62293
14	90074	64182	65162
15	94422	67104	68551
16	98758	69322	71747
17	101664	71311	74229
18	103404	73288	76053
19	101392	72727	75340
20	96482	71697	73931
21	91668	69182	71053
22	82767	63989	65789
23	72688	57065	58804
24	63355	50901	52426

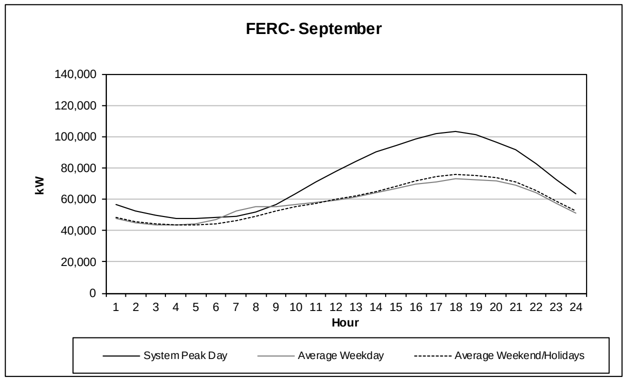


Figure 2.3-58 FERC October Daily Load Profiles

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	63275	51360	49522
2	62310	50408	48363
3	62149	50219	48023
4	62453	50581	48266
5	63996	52160	49199
6	67960	55899	51099
7	73919	61810	54288
8	77607	65165	57738
9	77670	64488	59216
10	78117	62971	58646
11	77896	61401	57790
12	77012	60017	56976
13	76336	58797	56085
14	75661	58009	55442
15	76071	57826	55381
16	77436	58101	55978
17	80519	59737	57921
18	84988	63323	61524
19	88733	67477	65086
20	87730	68742	66153
21	84945	66969	64554
22	81314	63414	61245
23	76661	58457	56497
24	71961	54145	52382

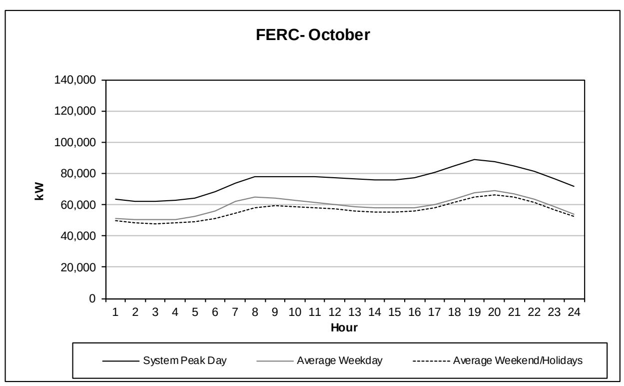


Figure 2.3-59 FERC November Daily Load Profiles

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	72529	58595	60987
2	71458	57800	59964
3	71213	57818	59774
4	71437	58540	60121
5	72793	60447	61243
6	75996	64337	63328
7	80693	70030	66431
8	83565	72016	69107
9	83556	70111	69465
10	82381	68085	68590
11	80110	66318	67002
12	78732	65052	65609
13	77877	64009	64353
14	77715	63817	63171
15	77909	64280	62966
16	79311	65724	64477
17	84100	69794	68623
18	90029	76603	74772
19	89502	77811	75565
20	87478	76596	74368
21	84936	74548	72615
22	80646	70703	69256
23	75302	65843	64769
24	70384	61901	61026

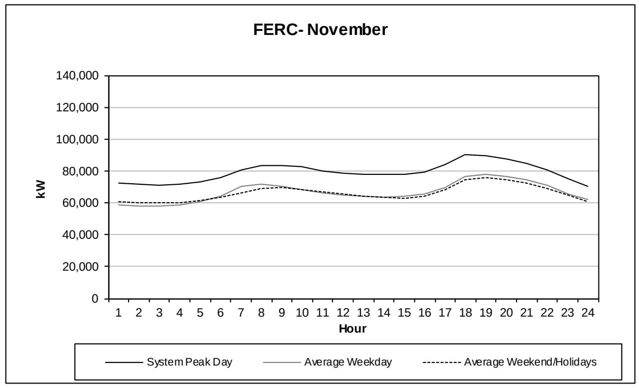
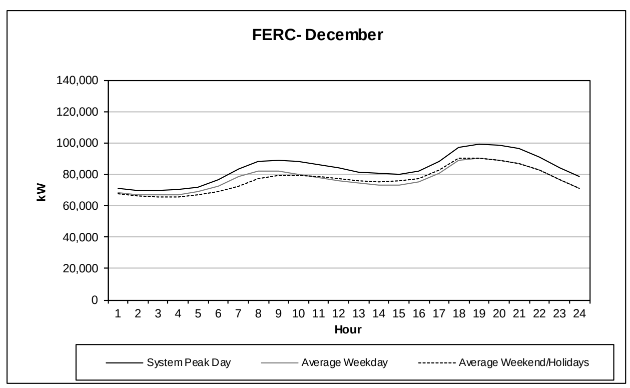


Figure 2.3-60 FERC December Daily Load Profiles

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	71264	67973	67715
2	69914	66759	66077
3	69655	66603	65580
4	70007	67021	65741
5	71954	68785	66772
6	76481	72569	68851
7	83530	78478	72594
8	87988	82220	76950
9	88854	81704	79289
10	87888	80143	79598
11	86070	78057	78492
12	83829	76141	77229
13	81306	74271	75913
14	80566	73219	75053
15	79933	73133	75575
16	82098	74985	77400
17	87978	80550	82918
18	97424	88961	90299
19	99238	90067	90584
20	98402	88795	88941
21	96108	86663	86741
22	90878	82380	82572
23	83868	76270	76428
24	78499	71011	71011



2.4 EVALUATION OF EXISTING RESOURCES

This Section includes existing resources information required by Rule 3607. Specifically, Rule 3607(a) requires the Company to describe its existing resources, all utility-owned generation facilities and energy storage systems for which the utility has obtained a Certificate of Public Convenience and Necessity ("CPCN") from the Commission pursuant to § 40-5-101, C.R.S. at the time the plan is filed, and existing or future purchases from other utilities or non-utilities pursuant to agreements effective at the time the plan is filed.

Company-Owned Resources

Table 2.4-1 on the following page lists the names and locations of generation facilities and energy storage systems owned by Public Service as required by Rule 3607(a)(I).

Table 2.4-1 Name and Location of Public Service-Owned Generation Facilities and Energy Storage Systems

Facility Name	Unit	Location
Alamosa	1,2	One mile south of the city of Alamosa, CO, in the San Luis Valley
Ames	1	South Fork of the San Miguel River, approximately ten miles south-southwest of Telluride, CO
Blue Spruce	1,2	N Powhaton Rd, Aurora, CO
Cabin Creek	1,2	South of Georgetown, CO
Cherokee	4,5,6,7	Commerce City, CO. Near intersection of Washington St. and 61st
Cheyenne Ridge	1	In Kit Carson and Cheyenne County near the eastern CO border
Comanche	1,2,3	South end of Pueblo, CO, east of I-25
Craig	1,2	Near Craig, CO
Fruita	1	Ten miles northwest of Grand Junction, CO, near the Town of Fruita
Ft. Lupton	1,2	Two miles northeast of Ft. Lupton, CO
Ft. St. Vrain	1,2,3,4,5,6	Three miles northwest of Platteville, CO
Georgetown	1,2	On South Clear Creek in Georgetown, CO
Hayden	1,2	On the Yampa River, two miles east of Hayden in western CO
Manchief	11,12	In Morgan County near Brush, CO
Pawnee	1	Four miles southwest of Brush, CO
Pena Station	1	Near 61st Ave and Tower Rd, Denver, CO
Rocky Mtn Energy Center	1,2,3	County Road 51, Keenesburg, CO
Rush Creek	1	In Elbert County near the community of Matheson, 60 miles southeast of Denver, CO
Rush Creek	2	Near the intersection of Cheyenne, Kit Carson, and Lincoln County, 35 miles east of Denver, CO
Salida	2	On the South Arkansas River, six miles east of Poncha Springs, CO
Shoshone	A,B	On the Colorado River in Glenwood Canyon, six miles east of Glenwood Springs, CO
Tacoma	1,2	On the Animas River, eighteen miles north of Durango, CO
Valmont	6,7,8	East Boulder, CO off of Arapahoe Road

Table 2.4-2 below provides the following information for Public Service-owned generation facilities and energy storage systems as required by Rule 3607(a)(II), (III), and (V):

- Gross Maximum Capacity
- Summer Net Dependable Capacity
- Fuel Type
- Heat Rate
- Estimated In-Service Year
- Estimated Remaining Useful Life (i.e., Estimated Retirement Year)

Table 2.4-2 Public Service Owned Generation Facilities and Energy Storage Systems

Facility Name & Unit	Gross Maximum Capacity (MW)	Summer Net Dependable Capacity (MW)	Fuel Type	Heat Rate (MMbtu/kWh) (1)	Estimated In-Service Year (2)	Estimated Retirement Year (2)
Alamosa 1	17	13	Gas	14.98	In-Service	2026
Alamosa 2	18	14	Gas	16.04	In-Service	2026
Ames	3	3	Hydro	n/a	In-Service	2050
Blue Spruce 1	146	130	Gas	10.54	In-Service	2050
Blue Spruce 2	150	134	Gas	10.43	In-Service	2050
Cabin Creek A	162	162	Storage	n/a	In-Service	2054
Cabin Creek B	162	162	Storage	n/a	In-Service	2054
Cherokee 4	335	310	Gas	10.63	In-Service	2027
Cherokee 5	182	168	Gas	9.99	In-Service	2055
Cherokee 6	182	168	Gas	9.99	In-Service	2055
Cherokee 7	248	240	Gas	6.82	In-Service	2055
Cheyenne Ridge	498	498	Wind	n/a	In-Service	2045
Comanche 1	360	325	Coal	10.19	In-Service	2022
Comanche 2	365	335	Coal	10.27	In-Service	2025
Comanche 3 (3)	536	500	Coal	9.49	In-Service	2069
Craig 1 (4)	43	42	Coal	10.37	In-Service	2025
Craig 2 (4)	41	40	Coal	10.22	In-Service	2039
Fruita 1	18	14	Gas	15.30	In-Service	2026
Ft. Lupton 1	50	44	Gas	12.67	In-Service	2026
Ft. Lupton 2	50	44	Gas	12.67	In-Service	2026
Ft. St. Vrain 1	312	301	Gas	7.72	In-Service	2041
Ft. St. Vrain 2	138	123	Gas	10.95	In-Service	2041
Ft. St. Vrain 3	143	128	Gas	10.95	In-Service	2041
Ft. St. Vrain 4	143	128	Gas	10.95	In-Service	2041
Ft. St. Vrain 5	162	144	Gas	10.18	In-Service	2049
Ft. St. Vrain 6	162	144	Gas	10.31	In-Service	2049
Georgetown 1	1	1	Hydro	n/a	In-Service	2036
Georgetown 2	1	1	Hydro	n/a	In-Service	2036
Hayden 1 (6)	149	135	Coal	10.44	In-Service	2030
Hayden 2 (7)	107	98	Coal	10.22	In-Service	2036
Manchief 11	151	131	Gas	9.99	2022	2038
Manchief 12	151	131	Gas	9.99	2022	2038
Pawnee 1	536	505	Coal	10.80	In-Service	2041
Pena Station	1	1	Solar	n/a	In-Service	2036
RMEC 1	159	145	Gas	10.69	In-Service	2049

Facility Name & Unit	Gross Maximum Capacity (MW)	Summer Net Dependable Capacity (MW)	Fuel Type	Heat Rate (MMbtu/kWh) (1)	Estimated In-Service Year (2)	Estimated Retirement Year (2)
RMEC 2	159	145	Gas	10.69	In-Service	2049
RMEC 3	303	290	Gas	7.47	In-Service	2049
Rush Creek I	400	400	Wind	n/a	In-Service	2043
Rush Creek II	200	200	Wind	n/a	In-Service	2043
Salida 2	1	1	Hydro	n/a	In-Service	2027
Shoshone A	8	8	Hydro	n/a	In-Service	2058
Shoshone B	8	8	Hydro	n/a	In-Service	2058
Tacoma 1	2	2	Hydro	n/a	In-Service	2050
Tacoma 2	2	2	Hydro	n/a	In-Service	2050
Valmont 6	51	43	Gas	12.80	In-Service	2026
Valmont 7	42	41	Gas	9.84	In-Service	2040
Valmont 8	42	41	Gas	9.84	In-Service	2040

(1) Unit heat rates are considered confidential information, and therefore the information provided is the average of summer, winter, and spring/fall heat rates.
(2) In-service year is the first year the unit is available for the summer peak and retirement year is the last summer peak the unit is available.
(3) PSCo capacity only (66.67% of total unit).
(4) PSCo capacity only (9.72% of total unit).
(6) PSCo capacity only (75.5% of total unit).
(7) PSCo capacity only (37.4% of total unit).

Table 2.4-3 below shows the projected annual capacity factor of Public Service-owned generation facilities and energy storage systems over the RAP as required by Rule 3607(a)(III).

Table 2.4-3 Projected Capacity Factors

Facility Name & Unit	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
COAL UNITS										
Comanche 1	77.1%	77.0%								
Comanche 2	73.7%	65.4%	77.5%	78.2%	72.5%					
Comanche 3	76.0%	80.8%	73.7%	82.5%	71.1%	78.4%	72.5%	81.5%	75.5%	82.6%
Craig 1	51.7%	45.4%	55.3%	54.7%	49.4%					
Craig 2	52.7%	47.1%	56.5%	56.2%	50.8%	56.8%	59.1%	62.4%	62.4%	62.4%
Hayden 1	61.7%	67.2%	69.6%	64.6%	66.9%	67.5%	67.5%	69.1%	69.1%	69.1%
Hayden 2	66.5%	57.9%	55.0%	61.5%	58.9%	58.0%	58.1%	58.3%	58.3%	58.3%
Pawnee 1	77.8%	66.5%	77.9%	77.4%	62.4%	64.5%	65.8%	68.4%	70.5%	70.1%
GAS COMBINED CYCLE & STEAM UNITS										
Cherokee 5	37.0%	33.2%	41.7%	40.9%	31.0%	37.5%	38.8%	43.6%	48.4%	46.9%
Cherokee 6	22.0%	21.2%	27.7%	24.9%	18.7%	23.4%	26.0%	30.1%	32.9%	32.3%
Cherokee 7	20.6%	17.8%	22.4%	22.1%	16.6%	20.7%	21.8%	25.2%	28.1%	27.6%
Ft. St. Vrain 1	19.4%	18.3%	18.9%	18.3%	14.3%	19.1%	20.1%	22.9%	26.8%	26.9%
Ft. St. Vrain 2	48.3%	37.4%	43.3%	46.4%	35.0%	44.0%	45.7%	49.8%	56.6%	56.1%
Ft. St. Vrain 3	27.0%	30.8%	27.5%	24.5%	19.0%	25.9%	28.2%	32.5%	38.0%	39.1%
Ft. St. Vrain 4	13.8%	15.2%	15.4%	12.6%	9.9%	16.5%	17.2%	19.9%	24.5%	24.8%
Rocky Mt. Energy Center 1	32.6%	35.8%	40.8%	35.7%	29.5%	32.6%	33.6%	38.8%	40.9%	40.9%

Facility Name & Unit	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rocky Mt. Energy Center 2	8.7%	9.2%	20.4%	18.5%	16.1%	22.5%	22.2%	25.8%	31.1%	29.2%
Rocky Mt. Energy Center 3	14.4%	15.5%	22.3%	19.1%	15.4%	18.5%	18.5%	21.6%	27.4%	26.8%
GAS COMBUSTION TURBINE UNITS										
Alamosa 1	0.28%	0.25%	0.04%	0.14%	0.03%	0.01%				
Alamosa 2	0.32%	0.24%	0.04%	0.17%	0.03%	0.03%				
Blue Spruce 1	0.40%	0.30%	0.28%	0.72%	0.39%	0.69%	0.30%	0.10%	0.02%	0.13%
Blue Spruce 2	1.03%	0.58%	0.78%	1.18%	0.69%	1.56%	0.55%	0.13%	0.03%	0.18%
Fruita 1	0.05%	0.02%	0.02%	0.03%	0.04%	0.02%				
Ft. Lupton 1	0.00%	0.18%	0.00%	0.00%	0.01%	0.00%				
Ft. Lupton 2	0.00%	0.10%	0.00%	0.00%	0.00%	0.00%				
Ft. St. Vrain 5	0.54%	0.46%	0.41%	0.62%	0.39%	1.22%	0.58%	0.12%	0.05%	0.21%
Ft. St. Vrain 6	0.26%	0.20%	0.30%	0.31%	0.29%	0.88%	0.42%	0.11%	0.05%	0.19%
Manchief 11	0.26%	0.10%	0.09%	0.11%	0.12%	0.05%	0.08%	0.03%	0.02%	0.02%
Manchief 12	0.26%	0.10%	0.09%	0.11%	0.12%	0.05%	0.08%	0.03%	0.02%	0.02%
Valmont 6	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
Valmont 7	0.01%	0.00%	0.02%	0.03%	0.03%	0.04%	0.04%	0.19%	0.41%	0.48%
Valmont 8	0.01%	0.00%	0.02%	0.03%	0.03%	0.04%	0.04%	0.19%	0.41%	0.48%
Cherokee 4	2.25%	0.00%	0.45%	0.61%	0.00%	0.24%	0.60%			
HYDRO UNITS										
Ames	28.5%	28.5%	28.5%	28.5%	28.5%	28.5%	28.5%	28.5%	28.5%	28.5%
Georgetown 1	31.6%	31.6%	31.6%	31.5%	31.6%	31.6%	31.6%	31.5%	31.6%	31.6%
Georgetown 2	31.6%	31.6%	31.6%	31.5%	31.6%	31.6%	31.6%	31.5%	31.6%	31.6%
Salida 2	32.6%	32.6%	32.6%	32.5%	32.6%	32.6%	32.6%			
Shoshone A	64.7%	64.6%	64.7%	64.6%	64.7%	64.7%	64.7%	64.6%	64.7%	64.7%
Shoshone B	64.7%	64.6%	64.7%	64.6%	64.7%	64.7%	64.7%	64.6%	64.7%	64.7%
Tacoma 1	24.1%	24.1%	24.1%	24.1%	24.1%	24.1%	24.1%	24.1%	24.1%	24.1%
Tacoma 2	24.1%	24.1%	24.1%	24.1%	24.1%	24.1%	24.1%	24.1%	24.1%	24.1%
SOLAR UNITS										
Pena Station	31.0%	30.5%	30.9%	30.8%	29.1%	29.6%	29.8%	30.4%	30.6%	30.3%
PUMPED STORAGE UNITS										
Cabin Creek A	26.8%	16.2%	15.7%	16.2%	16.1%	16.6%	16.2%	15.9%	15.4%	16.3%
Cabin Creek B	26.8%	16.2%	15.7%	16.2%	16.1%	16.6%	16.2%	15.9%	15.4%	16.3%
WIND UNITS										
Cheyenne Ridge	45.0%	44.1%	45.0%	45.5%	38.2%	39.2%	40.5%	43.8%	44.9%	44.4%
Rush Creek I	37.0%	36.1%	37.1%	37.5%	30.5%	31.6%	32.8%	35.9%	37.0%	36.6%
Rush Creek II	37.0%	36.1%	37.1%	37.5%	30.5%	31.6%	32.8%	35.9%	37.0%	36.6%

Table 2.4-4 shows the projected annual availability factor of Public Service-owned generation facilities and energy storage systems over the RAP as required by Rule 3607(a)(III).

Table 2.4-4 Projected Availability Factors

Facility Name & Unit	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
COAL UNITS										
Comanche 1	92.2%	95.9%								
Comanche 2	91.5%	85.3%	95.2%	95.2%	95.2%					
Comanche 3	84.6%	92.1%	83.3%	92.1%	83.8%	92.1%	83.8%	92.1%	83.8%	92.1%
Craig 1	87.2%	87.2%	87.2%	87.2%	87.2%					
Craig 2	87.2%	87.2%	87.2%	87.2%	87.2%	87.2%	87.2%	87.2%	87.2%	87.2%
Hayden 1	78.1%	95.4%	95.4%	86.3%	90.2%	90.2%	90.2%	90.2%	90.2%	90.2%
Hayden 2	94.0%	94.0%	85.0%	94.0%	88.3%	88.3%	88.3%	88.3%	88.3%	88.3%
Pawnee 1	95.1%	83.4%	95.1%	95.1%	84.9%	84.9%	84.9%	85.0%	84.9%	84.9%
GAS COMBINED CYCLE & STEAM UNITS										
Cherokee 5	85.9%	79.1%	87.3%	87.3%	87.3%	87.4%	87.3%	87.3%	87.4%	87.4%
Cherokee 6	78.9%	88.5%	91.0%	84.6%	86.3%	86.1%	86.3%	86.3%	86.1%	86.3%
Cherokee 7	85.2%	72.0%	82.4%	82.5%	82.5%	82.5%	82.5%	82.4%	82.4%	82.5%
Ft. St. Vrain 1	92.6%	92.6%	84.6%	92.6%	90.2%	90.2%	90.2%	90.2%	90.2%	89.8%
Ft. St. Vrain 2	93.6%	72.1%	93.6%	96.2%	96.2%	96.2%	96.2%	96.2%	96.2%	96.2%
Ft. St. Vrain 3	87.4%	92.0%	93.3%	85.6%	90.8%	90.8%	91.0%	90.9%	90.8%	91.0%
Ft. St. Vrain 4	89.5%	94.3%	95.6%	87.7%	93.2%	93.2%	93.2%	93.1%	93.1%	93.2%
Rocky Mt. Energy Center 1	85.1%	94.0%	95.3%	78.6%	89.0%	88.9%	88.9%	89.0%	88.9%	89.0%
Rocky Mt. Energy Center 2	86.2%	96.6%	90.3%	79.7%	93.9%	93.9%	93.9%	93.9%	93.9%	93.9%
Rocky Mt. Energy Center 3	91.1%	91.1%	91.1%	75.7%	88.6%	88.7%	88.7%	88.6%	88.7%	88.6%
GAS COMBUSTION TURBINE UNITS										
Alamosa 1	94.6%	94.6%	94.3%	95.1%	97.0%	97.0%				
Alamosa 2	94.6%	94.6%	95.1%	94.9%	97.0%	97.0%				
Blue Spruce 1	84.8%	97.8%	98.6%	98.6%	94.5%	94.5%	94.5%	94.5%	94.5%	94.5%
Blue Spruce 2	87.1%	97.8%	96.1%	99.4%	95.8%	95.9%	95.9%	95.9%	95.9%	95.7%
Fruita 1	79.1%	79.1%	79.8%	79.4%	81.0%	81.0%				
Ft. Lupton 1	73.0%	73.0%	72.2%	72.2%	72.1%	72.2%				
Ft. Lupton 2	71.0%	71.0%	70.2%	70.2%	70.2%	70.2%				
Ft. St. Vrain 5	80.1%	84.6%	85.8%	85.8%	83.2%	83.2%	83.2%	83.2%	83.2%	83.2%
Ft. St. Vrain 6	81.8%	86.8%	88.0%	88.0%	86.3%	86.3%	86.3%	86.3%	86.3%	86.3%
Manchief 11	95.6%	96.2%	93.2%	93.2%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%
Manchief 12	95.6%	96.2%	93.2%	93.2%	95.6%	95.6%	95.6%	95.6%	95.6%	95.6%
Valmont 6	95.0%	95.0%	90.0%	90.0%	90.0%	90.0%				
Valmont 7	95.0%	94.0%	93.1%	93.1%	93.1%	93.1%	93.1%	93.1%	93.1%	93.1%
Valmont 8	95.0%	94.0%	93.1%	93.1%	93.1%	93.1%	93.1%	93.1%	93.1%	93.1%
Cherokee 4	85.4%	85.4%	85.4%	85.4%	85.4%	85.4%	85.4%			
HYDRO UNITS										
Ames	28.5%	28.5%	28.5%	28.5%	28.5%	28.5%	28.5%	28.5%	28.5%	28.5%
Georgetown 1	31.6%	31.6%	31.6%	31.5%	31.6%	31.6%	31.6%	31.5%	31.6%	31.6%
Georgetown 2	31.6%	31.6%	31.6%	31.5%	31.6%	31.6%	31.6%	31.5%	31.6%	31.6%
Salida 2	32.6%	32.6%	32.6%	32.5%	32.6%	32.6%	32.6%			

Facility Name & Unit	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Shoshone A	64.7%	64.7%	64.7%	64.6%	64.7%	64.7%	64.7%	64.6%	64.7%	64.7%
Shoshone B	64.7%	64.7%	64.7%	64.6%	64.7%	64.7%	64.7%	64.6%	64.7%	64.7%
Tacoma 1	24.1%	24.1%	24.1%	24.1%	24.1%	24.1%	24.1%	24.1%	24.1%	24.1%
Tacoma 2	24.1%	24.1%	24.1%	24.1%	24.1%	24.1%	24.1%	24.1%	24.1%	24.1%
SOLAR UNITS										
Pena Station	31.1%	31.1%	31.1%	31.1%	31.1%	31.1%	31.1%	31.1%	31.1%	31.1%
PUMPED STORAGE UNITS										
Cabin Creek A	94.3%	94.3%	94.3%	94.3%	94.3%	94.3%	94.3%	94.3%	94.3%	94.3%
Cabin Creek B	94.3%	94.3%	94.3%	94.3%	94.3%	94.3%	94.3%	94.3%	94.3%	94.3%
WIND UNITS										
Cheyenne Ridge	50.8%	50.8%	50.8%	50.8%	50.8%	50.8%	50.8%	50.8%	50.8%	50.8%
Rush Creek I	42.7%	42.7%	42.7%	42.7%	42.7%	42.7%	42.7%	42.7%	42.7%	42.7%
Rush Creek II	42.7%	42.7%	42.7%	42.7%	42.7%	42.7%	42.7%	42.7%	42.7%	42.7%

In-Service Date for Facilities Granted a CPCN

Rule 3607(a)(IV) requires the Company to provide estimated in-service dates for utility-owned generation and energy storage facilities not in service at the time the ERP is filed.

The only utility-owned generation facility for which a CPCN has been granted but is not in service at the time of filing this 2021 ERP, involves upgrades at the Company's Cabin Creek pumped storage facility. The upgrades include: (1) increasing the existing pump turbine unit capacity from 324 MW to 360 MW, and (2) expanding the size of the upper reservoir to provide an additional 75 acre-feet of storage capacity. Together, these upgrades will provide an additional 112 MWh of energy generation per storage cycle and 36.6 MW of capacity, and the round-trip overall storage efficiency will be improved from 64.4 to 72.4 percent. A CPCN was granted on August 19, 2015 (Decision No. C15-0955, Proceeding No. 15A-0304E). The estimated in-service date for Unit A is May 2021; the estimated in-service date for Unit B is June 2022.

Purchased Power

Public Service buys a significant amount of firm capacity and energy through power purchase agreements ("PPAs") with various agreement term lengths and fuel resource types. These PPAs contain provisions that detail the amount and type of capacity available to Public Service. Some are "unit contingent," meaning that the delivered capacity is contingent upon the availability of certain generating facilities. If one of these facilities is not available for operation, the supplying counterparty can reduce the amount of capacity provided to Public Service.

Table 2.4-5 below summarizes the following for all PPAs to which Public Service currently purchases firm capacity as required by Rule 3607(a)(VI) a description of contract provisions that allow for modification of the amount of capacity or energy from generation facilities or energy storage systems for current Public Service PPAs):

- Resource Type
- Firm Summer Capacity
- PPA Summer Expiration Year

Table 2.4-5 PPA Fuel Type, Summer Capacity, and Duration

Power Purchase Agreement	Fuel Type	Firm Summer Capacity (MW) (1)	Expires (2)
Arapahoe 5,6,7	Gas	118.8	2023
Bighorn (5)	Solar	114.4	2041
Bronco Plains (7)	Wind	40.3	2045
Brush 1	Gas	60.0	2025
Brush 2	Gas	75.5	2021
Brush 3	Gas	30.0	2025
Brush 4D	Gas	147.0	2022
Cedar Creek (7)	Wind	40.3	2027
Cedar Creek II (7)	Wind	33.6	2036
Cedar Point (7)	Wind	33.8	2031
City of Boulder - Betasso (3)	Hydro	1.7	2027
City of Boulder - Lakewood (3)	Hydro	1.7	2027
City of Boulder - Silver Lake (3)	Hydro	1.7	2027
KEPCO Alamosa (5)	Solar	13.6	2031
Colorado Green (7)	Wind	21.7	2038
Comanche (5)	Solar	55.8	2041
DWB - Dillon (3)	Hydro	1.1	2026
DWB - Foothills (3)	Hydro	1.3	2026
DWB - Gross Reservoir (3)	Hydro	4.5	2027
DWB - Hillcrest (3)	Hydro	1.3	2026
DWB - Roberts Tunnel (3)	Hydro	3.4	2026
DWB - Strontia (3)	Hydro	0.7	2026
Fountain Valley 1-6	Gas	242.0	2031
Front Range-Midway (5)	Solar	47.9	2042
Front Range-Midway (8)	Storage	30.3	2042
Golden West (7)	Wind	33.4	2040
Greater Sandhill (5)	Solar	8.8	2030
Hartsel (5)	Solar	34.5	2047
Hooper (5)	Solar	23.2	2036
Limon I (7)	Wind	26.8	2037
Limon II (7)	Wind	26.8	2037

Power Purchase Agreement	Fuel Type	Firm Summer Capacity (MW) (1)	Expires (2)
Limon III (7)	Wind	26.9	2039
Logan (7)	Wind	26.9	2027
Manchief	Gas	301.0	2021
Mountain Breeze (7)	Wind	23.0	2045
Neptune (5)	Solar	119.8	2047
Neptune (8)	Storage	75.6	2047
Northern Colorado I (7)	Wind	20.3	2034
Northern Colorado II (7)	Wind	3.0	2029
PacifiCorp Exchange	Coal	150.0	2022
Peetz Table (7)	Wind	26.7	2032
Plains End I	Gas	113.0	2027
Plains End II	Gas	115.6	2027
Redlands Water & Power (3)	Hydro	0.8	2024
Ridge Crest (6)	Wind	3.5	2022
San Luis (5)	Solar	13.9	2031
Spindle Hill (1 + 2)	Gas	314.0	2026
Spring Canyon (7)	Wind	8.0	2025
STS (Mt. Elbert) (4)	Hydro	0.0	2026
Sun Mountain (5)	Solar	95.8	2037
SunE Alamosa I (5)	Solar	3.1	2027
Thunder Wolf (5)	Solar	95.8	2047
Thunder Wolf (8)	Storage	60.5	2047
Titan (5)	Solar	23.5	2038
Twin Buttes (7)	Wind	10.1	2026
Waste Management	Biomass	3.3	2023

(1) Firm capacity in 2023 due to different Effective Load Carrying Capabilities (ELCC) in 2021/2022 and ELCCs are constant in 2023 forward for existing resources.
(2) Final year in which capacity is available to serve peak summer load.
(3) Firm capacity reflects 55.4% ELCC.
(4) Energy only contract.
(5) Firm capacity reflects 47.9% ELCC.
(6) Firm capacity reflects 11.9% ELCC in 2022 (due to expiration before 2023).
(7) Firm capacity reflects 13.4% ELCC.
(8) Firm capacity reflects 60.5% ELCC.

Table 2.4-6 provides a description of contract provisions that allow for modification of the amount of capacity or energy from generation facilities or energy storage systems for current Public Service PPAs as required by Rule 3607(a)(VI).

Table 2.4-6 PPA Contract Modification Terms

Power Purchase Agreement	Contract Modifications Terms
Arapahoe 5,6,7	Seller shall offer any Excess Energy and/or Excess Capacity providing Company a Commercially Reasonable period of time of not less than 10 Business Days to respond to the offer.
Brush 1/3	PSCo has the right to any Excess Capacity and Excess at the price offered by the Seller.
Cedar Creek	PSCo has the right to either accept or decline any Excess Renewable Energy produced during any commercial operation year.
Cedar Creek II	PSCo has the right to either accept or decline any Excess Renewable Energy produced during any commercial operation year.
Cedar Point	PSCo has the right to either accept or decline any Excess Renewable Energy produced during any commercial operation year.
KEPCO Alamosa	PSCo has the right to accept or decline any energy produced in excess of 115% of the Committed Solar Energy
Comanche (solar)	PSCo has the right to accept or decline any energy produced in excess of 115% of the Committed Solar Energy
Fountain Valley 1-6	Seller shall offer any Excess Energy and/or Excess Capacity providing Company a Commercially Reasonable period of time of not less than 10 Business Days to respond to the offer.
Front Range-Midway	PSCo has the right to accept or decline any energy produced in excess of 115% of the Committed Solar Energy.
Hartsel	Company shall elect by notice to Seller either to accept or to decline any Excess Energy generated by the Facility through the balance of such Commercial Operation Year. Failure by Company to deliver such notice shall be deemed an election by Company to decline any Excess Energy for that Commercial Operation Year.
Hooper	PSCo has the right to accept or decline any energy produced in excess of 115% of the Committed Solar Energy.
Limon I	PSCo has the right to either accept or decline any Excess Renewable Energy produced during any commercial operation year.
Limon II	PSCo has the right to either accept or decline any Excess Renewable Energy produced during any commercial operation year.
Manchief	PSCo has the right to any Excess Capacity and Excess at the price offered by the Seller.
Neptune	PSCo has the right to accept or decline any energy produced in excess of 115% of the Committed Solar Energy.
San Luis	PSCo has the right to accept or decline any energy produced in excess of 115% of the Committed Solar Energy.

Power Purchase Agreement	Contract Modifications Terms
Spindle Hill 1 + 2	Seller shall offer any Excess Energy and/or Excess Capacity providing Company a Commercially Reasonable period of time of not less than 10 Business Days to respond to the offer.
Sun Mountain	PSCo has the right to accept or decline any energy produced in excess of 115% of the Committed Solar Energy.
Thunder Wolf	PSCo has the right to accept or decline any energy produced in excess of 115% of the Committed Solar Energy.
Titan	Seller shall notify Company promptly upon Seller's delivery of Renewable Energy hereunder that exceeds 110% of the Committed Energy for a Commercial Operation Year. Within 10 Business Days of any such notice, Company shall elect by notice to Seller either to accept or to decline any Excess Energy generated by the Facility through the balance of such Commercial Operation Year.

Table 2.4-7 provides the performance characteristics of Public Service-owned energy storage systems including but not limited to discharge rates and durations, charging rates, response time, and cycling losses and limitations as required by Rule 3607(a)(VIII).

Table 2.4-7 Performance Characteristics of Public Service-Owned Energy Storage Systems

Energy Storage System / Technology	Discharge Rate	Duration (1)	Charging Rate (2)	Response Time	Cycling Losses / Limitations
Cabin Creek A / 162 MW Pumped Hydro	162 MW Maximum	8 Hours	18.5 Hours	10 minutes Maximum	Requires 1.5 MW to pump same amount of water required to generate 1 MW. Cabin Creek is allowed to maintain a maximum of 2020 acre feet of water in inventory. This allows for 1407 MW-hrs of generation with a full upper reservoir. This will decrease if water inventory is less due to losses.
Cabin Creek B / 162 MW Pumped Hydro	162 MW Maximum	8 Hours	18.5 Hours	10 minutes Maximum	
Cabin Creek A+B / 324 MW Pumped Hydro	324 MW Maximum	4 Hours	9.5 Hours	20 minutes Maximum	

(1) Duration for maximum discharge rate.
(2) Storage reservoir fill rate.

Table 2.4-8 provides the performance characteristics of energy storage systems purchased from utilities and non-utilities, including but not limited to discharge rates and durations, charging rates, response time; and cycling losses and limitations as required by Rule 3607(a)(IX).

Table 2.4-8 Performance Characteristics of Energy Storage Systems Contracted Through PPA (Highly Confidential)

Energy Storage System / Technology	Discharge Rate	Duration	Charging Rate	Response Time	Cycling Losses / Limitations
Front Range-Midway / 50 MW Lithium Ion Batteries (expected)	XX MW Maximum	Minimum XXX Minutes Discharging Rate	XXX MW Maximum	XXX seconds	Round Trip Efficiency During Term of PPA: XXX
Neptune / 125 MW Lithium Ion Batteries	XXX MW Maximum	Minimum X Hours Discharging Rate	XXX MW Maximum	XXX seconds	Round Trip Efficiency During Term of PPA: XXX
Thunder Wolf / 100 MW Lithium Ion Batteries	XXX MW Maximum	Minimum X Hours Discharging Rate	XXX MW Maximum	XXX seconds	Round Trip Efficiency During Term of PPA: XXX

Note: Highly Confidential PPA data is indicated by blue highlight.

Projected Emissions of Existing Resources

Tables 2.4-9 through 2.4-18 provide the projected emissions, in terms of pounds per MWH and short-tons per year, of sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter (PM_10), mercury (HG) and carbon dioxide (CO_2) for: (1) generation facilities and energy storage systems owned by Public Service, and generation facilities from which Public Service has PPAs in effect at the time of this plan filing as required by Rule 3607(a)(X); and (2) generic resources included in the Company's modeling as required by Rule 3604(g).

Table 2.4-9 Projected CO_2 Emissions (Tons) From Existing Resources

	Alternative Plan							
Year	SC1	SC2	SC3	SC4	SC5	SC6	SC7	SC8
2020	17,032,402	17,032,403	17,032,402	17,032,402	17,032,401	17,032,401	17,032,403	17,032,404
2021	16,598,748	16,598,747	16,598,748	16,598,748	16,598,748	16,598,748	16,598,747	16,598,747
2022	15,607,223	15,607,220	15,607,223	15,607,220	15,607,222	15,607,222	15,607,223	15,607,222
2023	13,842,739	13,842,737	13,842,736	13,842,736	13,842,738	13,842,737	13,842,738	13,842,735
2024	14,186,745	14,217,461	14,246,159	14,186,745	14,249,209	14,247,936	14,246,157	14,247,934
2025	12,099,386	9,938,125	12,161,558	12,107,443	12,155,494	12,161,661	12,161,554	12,161,656
2026	10,395,514	7,836,921	10,366,804	10,383,497	10,397,095	10,383,486	10,381,972	10,368,192
2027	9,798,732	7,049,240	9,719,063	9,720,239	9,323,078	9,703,494	9,718,929	9,720,292
2028	9,591,180	6,879,485	6,906,567	4,599,160	6,429,305	6,880,605	9,529,985	9,531,414
2029	8,548,500	5,677,864	5,712,580	3,688,838	5,214,913	3,117,376	5,623,369	3,011,629
2030	8,510,644	3,951,409	3,992,586	3,369,251	4,550,225	2,894,827	3,910,233	2,765,130
2031	8,267,477	3,962,257	4,003,554	3,380,568	4,414,212	2,907,305	3,919,927	2,776,615
2032	8,464,677	3,963,852	4,004,504	3,378,045	4,263,458	2,866,824	3,877,001	2,735,666
2033	8,260,899	3,956,699	3,993,842	3,307,219	4,102,256	2,850,047	3,873,712	2,719,339
2034	8,430,951	3,935,193	3,972,396	3,296,113	4,082,919	2,786,373	3,849,816	2,653,922
2035	8,269,656	3,923,710	3,963,285	3,226,653	3,899,618	2,809,467	3,847,893	2,686,211
2036	8,404,335	3,892,753	3,940,365	3,183,597	3,954,132	2,733,160	3,786,784	2,609,640
2037	7,944,014	3,852,288	3,891,376	3,147,843	3,767,518	2,716,502	3,754,479	2,583,307
2038	7,524,077	3,874,351	3,874,901	3,221,307	3,865,146	2,775,154	3,856,805	2,631,471
2039	7,073,894	3,731,865	3,730,571	3,186,239	3,710,672	2,784,091	3,740,655	2,645,843
2040	6,304,152	2,458,906	2,461,235	2,754,194	2,273,993	2,447,138	2,439,379	2,410,357
2041	5,650,231	1,966,603	1,973,777	2,218,522	1,900,873	1,984,589	1,973,717	1,994,252
2042	4,153,225	1,094,506	1,101,589	1,221,497	1,101,701	1,101,718	1,101,645	1,102,695
2043	3,722,822	924,858	929,503	1,007,295	929,543	929,543	929,519	931,270
2044	3,419,978	798,736	804,343	887,417	804,316	804,331	804,302	805,016
2045	752,941	663,795	666,623	739,763	666,653	666,620	666,665	667,506
2046	649,280	539,124	541,844	592,946	541,758	541,829	541,795	542,448
2047	474,279	396,818	398,598	433,990	398,626	398,618	398,612	399,128
2048	293,141	255,711	256,768	272,922	256,755	256,753	256,735	256,725
2049	152,674	133,240	133,536	143,083	133,509	133,514	133,525	133,511
2050	0	0	0	0	0	0	0	0

Table 2.4-10 Projected CO_2 Emissions (Tons) From Generic Resources

	Alternative Plan							
Year	SC1	SC2	SC3	SC4	SC5	SC6	SC7	SC8
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0
2026	0	0	33,980	19,614	0	19,614	19,614	33,981
2027	23,688	103,046	37,710	37,732	421,877	48,672	37,710	37,751
2028	51,073	137,431	139,701	199,079	566,731	137,685	57,243	57,241
2029	127,208	240,792	230,574	248,454	700,000	428,794	276,700	495,564
2030	83,507	194,603	190,703	226,560	656,480	345,529	224,359	373,312
2031	96,345	201,123	194,622	244,080	661,950	340,428	215,890	381,770
2032	124,555	249,388	245,885	303,158	682,645	437,335	281,381	481,831
2033	149,536	267,539	265,731	324,416	713,145	469,129	302,043	498,221
2034	132,862	275,448	273,612	323,959	623,034	452,735	310,596	482,019
2035	118,416	228,189	223,203	273,806	632,162	370,469	249,626	389,927
2036	135,691	264,192	249,346	317,155	588,265	413,239	282,517	433,698
2037	172,044	287,943	280,706	319,834	634,768	438,558	296,102	445,720
2038	167,948	291,584	291,015	345,574	553,384	459,403	308,844	466,206
2039	194,040	303,956	305,214	353,689	555,900	476,375	295,207	477,687
2040	538,669	835,279	834,152	722,494	910,583	822,017	820,814	792,927
2041	507,923	648,943	645,426	626,198	697,537	640,651	645,160	634,948
2042	855,571	1,142,345	1,136,797	1,114,375	1,136,824	1,136,799	1,136,789	1,134,058
2043	752,008	952,391	948,398	957,050	948,415	948,402	948,389	947,652
2044	682,485	832,536	831,137	832,172	831,146	831,136	831,138	830,727
2045	692,276	696,406	694,221	694,550	694,228	694,219	694,212	694,371
2046	524,049	543,201	541,287	548,687	541,296	541,288	541,283	541,121
2047	399,784	417,625	416,504	423,576	416,512	416,505	416,502	416,260
2048	287,954	293,698	293,169	299,706	293,172	293,169	293,165	293,164
2049	149,421	152,683	152,632	154,926	152,634	152,632	152,631	152,630
2050	0	0	0	0	0	0	0	0

Table 2.4-11 Projected SO_2 Emissions (Tons) From Existing Resources

	Alternative Plan							
Year	SC1	SC2	SC3	SC4	SC5	SC6	SC7	SC8
2020	6,426	6,426	6,426	6,426	6,426	6,426	6,426	6,426
2021	7,264	7,264	7,264	7,264	7,264	7,264	7,264	7,264
2022	6,720	6,720	6,720	6,720	6,720	6,720	6,720	6,720
2023	5,521	5,521	5,521	5,521	5,521	5,521	5,521	5,521
2024	5,654	5,633	5,666	5,654	5,667	5,666	5,666	5,666
2025	4,948	3,201	4,958	4,945	4,962	4,957	4,958	4,957
2026	4,180	2,284	4,173	4,174	4,180	4,174	4,174	4,174
2027	3,980	2,134	3,959	3,959	3,988	3,958	3,958	3,959
2028	3,674	1,886	1,890	713	1,901	1,887	3,652	3,652
2029	2,994	1,132	1,134	42	1,144	20	1,130	16
2030	3,032	542	542	37	941	18	537	15
2031	2,925	541	541	37	894	18	537	15
2032	3,007	543	543	36	887	18	538	14
2033	2,890	540	540	34	812	18	537	14
2034	2,985	542	543	36	886	18	537	14
2035	2,899	540	540	33	801	17	536	13
2036	2,920	541	542	33	882	17	537	13
2037	2,715	539	539	32	802	17	536	13
2038	2,371	539	533	32	879	17	536	13
2039	2,139	482	466	31	800	16	531	13
2040	1,883	12	12	19	11	12	12	12
2041	1,798	10	10	13	9	10	10	10
2042	1,171	5	5	8	5	5	5	5
2043	1,062	5	5	7	5	5	5	5
2044	973	5	5	7	5	5	5	5
2045	7	5	5	8	5	5	5	5
2046	7	5	5	7	5	5	5	5
2047	7	5	5	7	5	5	5	5
2048	6	5	5	6	5	5	5	5
2049	5	5	5	7	5	5	5	5
2050	3	3	3	6	3	3	3	3

Table 2.4-12 Projected SO_2 Emissions (Tons) From Generic Resources

	Alternative Plan							
Year	SC1	SC2	SC3	SC4	SC5	SC6	SC7	SC8
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0
2027	0	1	0	0	2	0	0	0
2028	0	1	1	1	3	1	0	0
2029	1	1	1	1	4	2	1	3
2030	0	1	1	1	4	2	1	2
2031	0	1	1	1	4	2	1	2
2032	1	1	1	2	4	2	1	2
2033	1	1	1	2	4	2	2	3
2034	1	1	1	2	3	2	2	2
2035	1	1	1	1	3	2	1	2
2036	1	1	1	2	3	2	1	2
2037	1	1	1	2	3	2	1	2
2038	1	1	1	2	3	2	2	2
2039	1	2	2	2	3	2	1	2
2040	3	4	4	4	5	4	4	4
2041	3	4	4	4	4	4	4	4
2042	6	8	8	7	8	8	8	7
2043	6	7	7	7	7	7	7	7
2044	6	7	7	7	7	7	7	7
2045	7	7	7	7	7	7	7	7
2046	7	7	7	7	7	7	7	7
2047	7	7	7	7	7	7	7	7
2048	8	8	8	8	8	8	8	8
2049	8	8	8	8	8	8	8	8
2050	10	10	10	10	10	10	10	10

Table 2.4-13 Projected NO_x Emissions (Tons) From Existing Resources

	Alternative Plan							
Year	SC1	SC2	SC3	SC4	SC5	SC6	SC7	SC8
2020	7,582	7,582	7,582	7,582	7,582	7,582	7,582	7,582
2021	7,914	7,914	7,914	7,914	7,914	7,914	7,914	7,914
2022	7,349	7,349	7,349	7,349	7,349	7,349	7,349	7,349
2023	6,038	6,038	6,038	6,038	6,038	6,038	6,038	6,038
2024	6,165	6,199	6,184	6,165	6,185	6,184	6,184	6,184
2025	5,437	4,753	5,453	5,435	5,455	5,453	5,453	5,453
2026	3,488	2,592	3,480	3,484	3,489	3,484	3,483	3,481
2027	3,305	2,366	3,273	3,274	3,228	3,265	3,273	3,274
2028	3,150	2,242	2,249	1,521	2,194	2,242	3,131	3,132
2029	2,439	1,474	1,481	866	1,420	530	1,421	468
2030	2,467	917	924	787	1,183	499	872	439
2031	2,372	918	925	779	1,139	496	868	433
2032	2,420	884	889	742	1,066	450	827	386
2033	2,321	869	874	703	995	434	816	375
2034	2,392	864	869	703	1,046	423	810	362
2035	2,316	856	861	666	970	421	805	362
2036	2,355	853	859	669	1,027	410	798	352
2037	2,194	845	850	659	962	407	787	344
2038	2,013	831	823	665	1,018	409	798	349
2039	1,836	772	762	643	954	405	763	344
2040	1,628	330	330	446	298	328	327	323
2041	1,522	258	259	327	249	260	259	262
2042	1,147	95	96	139	96	96	96	96
2043	1,046	92	92	123	92	92	92	92
2044	973	92	93	130	93	93	93	93
2045	120	94	94	137	94	94	94	94
2046	135	93	93	125	93	93	93	93
2047	121	89	90	118	90	90	90	90
2048	104	87	87	110	87	87	87	87
2049	100	91	92	123	92	92	92	92
2050	73	72	73	113	73	73	73	73

Table 2.4-14 Projected NO_x Emissions (Tons) From Generic Resources

	Alternative Plan							
Year	SC1	SC2	SC3	SC4	SC5	SC6	SC7	SC8
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0
2026	0	0	12	7	0	7	7	12
2027	8	36	13	13	52	17	13	13
2028	17	47	48	69	75	47	19	19
2029	43	83	79	86	98	149	94	171
2030	28	66	64	78	88	119	76	128
2031	32	69	66	84	91	118	74	131
2032	40	84	82	103	102	149	94	163
2033	49	90	88	110	110	160	101	169
2034	44	92	91	110	97	154	104	163
2035	38	76	74	92	94	125	82	131
2036	44	88	83	107	89	140	94	147
2037	57	97	95	109	102	150	100	152
2038	55	98	98	117	86	157	104	159
2039	64	103	103	121	88	163	99	163
2040	126	181	178	152	168	174	174	166
2041	102	138	136	145	135	137	136	138
2042	171	248	247	247	247	247	247	246
2043	173	231	230	234	230	230	230	230
2044	178	230	229	233	229	229	229	229
2045	241	234	233	236	233	233	233	234
2046	220	223	222	230	222	222	222	223
2047	225	228	227	237	227	227	227	227
2048	229	240	239	242	239	239	239	239
2049	242	254	254	255	254	254	254	254
2050	288	310	309	305	309	309	309	309

Table 2.4-15 Projected HG Emissions (Tons) From Existing Resources

	Alternative Plan							
Year	SC1	SC2	SC3	SC4	SC5	SC6	SC7	SC8
2020	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
2021	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
2022	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
2023	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
2024	0.06	0.05	0.06	0.06	0.06	0.06	0.06	0.06
2025	0.05	0.03	0.05	0.05	0.05	0.05	0.05	0.05
2026	0.04	0.02	0.04	0.04	0.04	0.04	0.04	0.04
2027	0.04	0.02	0.04	0.04	0.04	0.04	0.04	0.04
2028	0.04	0.02	0.02	0.00	0.02	0.02	0.04	0.04
2029	0.04	0.02	0.02	0.00	0.02	0.00	0.02	0.00
2030	0.04	0.01	0.01	0.00	0.01	0.00	0.01	0.00
2031	0.04	0.01	0.01	0.00	0.01	0.00	0.01	0.00
2032	0.04	0.01	0.01	0.00	0.01	0.00	0.01	0.00
2033	0.04	0.01	0.01	0.00	0.01	0.00	0.01	0.00
2034	0.04	0.01	0.01	0.00	0.01	0.00	0.01	0.00
2035	0.04	0.01	0.01	0.00	0.01	0.00	0.01	0.00
2036	0.04	0.01	0.01	0.00	0.01	0.00	0.01	0.00
2037	0.03	0.01	0.01	0.00	0.01	0.00	0.01	0.00
2038	0.03	0.01	0.01	0.00	0.01	0.00	0.01	0.00
2039	0.03	0.01	0.01	0.00	0.01	0.00	0.01	0.00
2040	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 2.4-16 Projected HG Emissions (Tons) From Generic Resources

	Alternative Plan							
Year	SC1	SC2	SC3	SC4	SC5	SC6	SC7	SC8
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0
2035	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0
2041	0	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0
2049	0	0	0	0	0	0	0	0
2050	0	0	0	0	0	0	0	0

Table 2.4-17 Projected PM_10 Emissions (Tons) From Existing Resources

	Alternative Plan							
Year	SC1	SC2	SC3	SC4	SC5	SC6	SC7	SC8
2020	471	471	471	471	471	471	471	471
2021	417	417	417	417	417	417	417	417
2022	413	413	413	413	413	413	413	413
2023	391	391	391	391	391	391	391	391
2024	400	403	402	400	402	402	402	402
2025	339	364	341	339	341	341	341	341
2026	338	357	337	338	338	338	338	337
2027	310	316	307	308	290	307	307	308
2028	311	314	315	200	294	314	308	309
2029	284	285	287	184	265	170	285	168
2030	283	203	205	167	223	157	203	153
2031	272	203	205	167	217	156	203	152
2032	283	204	206	169	194	156	203	152
2033	273	202	204	164	188	154	201	150
2034	278	199	201	161	188	148	197	144
2035	270	197	199	158	178	148	196	144
2036	278	195	197	154	181	144	192	140
2037	261	191	193	151	173	141	189	137
2038	265	188	187	153	178	143	193	138
2039	249	179	179	151	171	142	181	137
2040	219	129	129	139	117	129	128	127
2041	197	104	104	115	100	105	104	105
2042	198	59	60	65	60	60	60	60
2043	183	57	57	61	57	57	57	57
2044	176	57	57	62	57	57	57	57
2045	63	57	57	63	57	57	57	57
2046	62	56	57	62	57	57	57	57
2047	60	55	55	60	55	55	55	55
2048	54	53	53	56	53	53	53	53
2049	56	56	56	59	56	56	56	56
2050	37	37	37	40	37	37	37	37

Table 2.4-18 Projected PM_10 Emissions (Tons) From Generic Resources

	Alternative Plan							
Year	SC1	SC2	SC3	SC4	SC5	SC6	SC7	SC8
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0
2026	0	0	1	1	0	1	1	1
2027	1	3	1	1	27	2	1	1
2028	2	4	4	6	36	4	2	2
2029	4	8	7	8	43	14	9	16
2030	3	6	6	7	41	11	7	12
2031	3	6	6	8	41	11	7	12
2032	4	8	8	10	41	14	9	15
2033	5	8	8	10	43	15	9	16
2034	4	9	9	10	37	14	10	15
2035	4	7	7	9	38	12	8	12
2036	4	8	8	10	35	13	9	14
2037	5	9	9	10	38	14	9	14
2038	5	9	9	11	33	15	10	15
2039	6	10	10	11	33	15	9	15
2040	26	42	42	36	50	42	41	40
2041	32	38	38	35	43	37	38	37
2042	60	79	79	77	79	79	79	79
2043	60	76	75	76	75	75	75	75
2044	66	78	78	78	78	78	78	78
2045	77	78	78	78	78	78	78	78
2046	73	77	77	77	77	77	77	76
2047	75	79	79	79	79	79	79	79
2048	83	84	84	86	84	84	84	84
2049	86	87	87	89	87	87	87	87
2050	107	109	109	111	109	109	109	109

Demand-Side Management

Rule 3607(a)(XI) requires the Company to describe the expected demand-side resources during the resource planning period from existing measures installed through Company-administered programs; and, from measures expected to be installed in the future through Company-administered programs in accordance with a Commission-approved plan.

On July 3, 2017, the Company filed an application in Proceeding No. 17A-0462EG for approval of a number of strategic issues relating to its DSM Plan, including long-term electric energy savings and demand response goals. Per the Commission's decision (Decision No. C14-0731) in the 2013 Strategic Issues proceeding (Proceeding No. 13A-0686EG), the Company has continued to use the approved demand response targets for purposes of determining resource need. Since the approved goals extend only through 2023, the current assumption is that levels of demand response remain constant after 2023 for purposes of resource need determination. Table 2.4-19 reflects the approved demand response goals.

Table 2.4-19 Demand Response Goals (MW)

Demand Response	2021	2022	2023
Strategic Issues DR Goal	489	503	520

To incorporate the impacts of future energy efficiency savings, the Company has reduced its sales forecast energy efficiency programs through 2023 consistent with the Commission's order in Proceeding No. 17A-0462EG. Table 2.4-20 reflects the energy efficiency targets through 2023.

Table 2.4-20 Energy Efficiency Goals (GWh)

Energy Efficiency	2021	2022	2023
Energy Efficiency Target	499	500	500

Utility Coordination

Rule 3607(b) requires the Company to coordinate its ERP filings with other utilities required to file resource plans, such that the amount of electricity purchases and sales between the utilities during the planning period is reflected uniformly in their respective plans. On the following pages, the Company has provided its coordination letters sent to: (1) Tri-State Generation and Transmission Association, Inc. ("Tri-State"), and (2) Black Hills Energy, requesting confirmation that the transaction information stated by Public Service in its coordination letter is consistent with that which each respective utility plans to use in any resource plan filing or reporting.

1800 Larimer Street
Denver, CO 80202

January 27, 2021

Mr. Brian Thompson
Resource Planning Manager
Tri-State Generation & Transmission Association
P.O. Box 33695
Denver, CO 80233

Subject: Public Service Company of Colorado's 2021 Electric Resource Plan

Dear Mr. Thompson,

The Colorado Public Utilities Commission's Resource Planning Rules require utilities to coordinate the reporting of purchases and sales for purposes of resource planning between the utilities. With this letter, Public Service Company of Colorado requests that Tri-State Generation & Transmission Association confirm that the transaction information listed below is consistent with that which Tri-State Generation & Transmission Association plans to use in any resource plan filing or reporting.

Specifically, our request relates to CPUC Rule 3607(b), which states:

> Utilities required to comply with these rules shall coordinate their [electric resource] plan filings such that the amount of electricity purchases and sales between utilities during the planning period is reflected uniformly in their respective plans. Disputes regarding the amount, timing, price, or other terms and conditions of such purchases and sales shall be fully explained in each utility's plan. If a utility files an interim plan as specified in rule 3603, the utility is not required to coordinate that filing with other utilities.

Currently, Public Service Company of Colorado has no firm purchases or sales with Tri-State Generation & Transmission Association as the counterparty. As such, Public Service Company of Colorado is not including any transactions with Tri-State Generation & Transmission Association in its determination of resource need.

If you agree with this information, please reply with a letter via email to Jim.Hill@xcelenergy.com of acknowledgement. We anticipate that we will include your reply, as well as this letter of request, in our plan filing to demonstrate compliance.

Thank you in advance for reviewing this information. Please contact me via email with any questions.

Sincerely,

Jim Hill
Director Resource Planning and Bidding
Public Service Company of Colorado
1800 Larimer Street
Suite 700
Denver, CO 80202

January 27,2021

Mr. Jim Hill
Director Resource Planning and Bidding
Public Service Company of Colorado
1800 Larimer Street
Suite 700
Denver, CO 80202

Subject: Public Service Company of Colorado's 2021 Electric Resource Plan

Dear Mr. Hill,

I concur with your statement in that currently, Public Service Company of Colorado has no firm purchases or sales with Tri-State Generation & Transmission Association as the counterparty.

Thank you for reaching out to Tri-State in this matter.

Sincerely,

Brian Thompson
Resource Planning Manager
Tri-State Generation & Transmission Association
P.O. Box 33695
Denver, CO 80233

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1800 Larimer Street
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January 27, 2021

Mr. Justin Briggs
Manager, Resource Planning
Black Hills Energy
P.O. Box 1400
Rapid City, SD 57709

Subject: Public Service Company of Colorado's 2021 Electric Resource Plan

Dear Mr. Briggs,

The Colorado Public Utilities Commission's Resource Planning Rules require utilities to coordinate the reporting of purchases and sales for purposes of resource planning between the utilities. With this letter, Public Service Company of Colorado requests that Black Hills Energy confirm that the transaction information listed below is consistent with that which Black Hills Energy plans to use in any resource plan filing or reporting.

Specifically, our request relates to CPUC Rule 3607(b), which states:

> Utilities required to comply with these rules shall coordinate their [electric resource] plan filings such that the amount of electricity purchases and sales between utilities during the planning period is reflected uniformly in their respective plans. Disputes regarding the amount, timing, price, or other terms and conditions of such purchases and sales shall be fully explained in each utility's plan. If a utility files an interim plan as specified in rule 3603, the utility is not required to coordinate that filing with other utilities.

Currently, Public Service Company of Colorado has no firm purchases or sales with Black Hills Energy as the counterparty. As such, Public Service Company of Colorado is not including any transactions with Black Hills Energy in its determination of resource need.

If you agree with this information, please reply with a letter via email to Jim.Hill@xcelenergy.com of acknowledgement. We anticipate that we will include your reply, as well as this letter of request, in our plan filing to demonstrate compliance.

Thank you in advance for reviewing this information. Please contact me via email with any questions.

Sincerely,

Jim Hill
Director Resource Planning and Bidding
Public Service Company of Colorado
1800 Larimer Street
Suite 700
Denver, CO 80202

Black Hills Energy
Ready

Justin Briggs
Manager, Resource Planning
Justin.briggs@blackhillscorp.com

PO Box 1400
Rapid City, SD 57702
P: 605-721-2652

February 11, 2021

Mr. Jim Hill
Director Resource Planning and Bidding
Public Service Company of Colorado
1800 Larimer Street
Suite 700
Denver, CO 80202

Subject: Public Service Company of Colorado's 2021 Electric Resource Plan

Dear Mr. Hill:

I acknowledge receipt of your letter dated January 27, 2021 and confirm Public Service Company of Colorado has no firm purchases or sales with Black Hills Energy as the counterparty.

Sincerely,

Justin Briggs
Manager, Resource Planning

2.5 BENCHMARKING

Background

In this Section, the Company presents benchmarking information contemplated by Proposed Draft Rule 3607(c) in Proceeding No. 19R-0096E. Although this Proposed Draft Rule will not be ultimately adopted by the Commission, the Company is voluntarily providing this supplemental information given the extensive stakeholder and Commission interest in the benchmarking concept over the course of Proceeding No. 19R-0096E.

Proposed Draft Rule 3607(c) states as follows:

> Benchmarking. For the purpose of identifying existing resources that potentially are not performing cost-effectively as compared to other resources available in the market, the utility shall compare the costs and performance of each of its existing supply-side resources greater than 20 MW of nameplate capacity to the costs and performance of the generic resources.

In Decision No. C19-0197, the Commission explained that the benchmarking proposal was intended to address the operating characteristics and costs of existing utility resources for multiple purposes. For example, it could identify the existing resources whose cost or performance deviate from expectations, which could potentially impact ratepayers in the future. It was also intended to inform the analysis for potential early plant retirements pursuant to Proposed Draft Rule 3604(k).[4]

In its comments filed on April 17, 2020 in Proceeding No. 19R-0096E, the Company described how it planned to implement the benchmarking exercise contemplated by Proposed Draft Rule 3607(c). Based on the expectation that benchmarking should focus on a comparison of the cost and performance of supply-side generation resources greater than 20 MW, the Company views the benchmarking exercise as an initial economic screening of existing generation resources greater than 20 MW, similar to the economic screening of bids using levelized cost information that the Commission has approved for use as part of the Phase II bid evaluation in past ERPs.

As initially described in its April 17, 2020 comments, the Company developed a spreadsheet tool to be used in developing a single metric for each existing generation resource type that: (1) captures both the cost and performance of the resource; and (2) can be easily and transparently compared to the same metric from a generic resource.

[4] Decision No. C19-0197, issued February 27, 2019, ¶ 68.

As discussed below, the Company compared projections of the cost and performance of all of its existing supply-side generation resources (owned and PPAs) greater than 20 MW with cost and performance estimates of generic resources. This included cost and performance projections for a total of 47 existing supply-side generating resources as summarized in Table 2.5-1 below.

Table 2.5-1 Summary of Existing Supply-Side Resources Assessed

Existing Resource Technology	Number of Existing Units Assessed
Coal	5
Gas-fired CC	6
Gas-fired CT	10
Gas Steam	1
Pumped Storage	1
Solar	5
Wind	19
Total	**47**

Methodology

The cost and performance of existing coal, gas combined cycle ("CC"), wind, and solar resources were represented using a $/MWh levelized energy cost ("LEC") metric calculated over the remaining resource asset life or PPA term at an assumed annual generation capacity factor. The cost and performance of existing gas combustion turbines ("CTs") and pumped storage resources were represented using a $/kW-mo levelized cost of capacity ("LCC") metric calculated over the remaining resource asset life or PPA term. Supply-side resources that have been approved by the Commission for early retirement (i.e., Comanche 1 and 2) and new resources that have been approved by the Commission but are not yet in-service at the time the 2021 ERP was filed (e.g., solar and solar with storage resources approved by the Commission in Public Service's Colorado Energy Plan Portfolio) were not included in this benchmarking exercise.

The LEC or LCC of the existing resources were then compared with the LEC or LCC of generic resources. The pool of generic technologies used in this comparison included wind, solar, 4-hour battery storage, gas-fired CC, and gas-fired CT. Information from the National Renewable Energy Laboratory ("NREL") 2020 Annual Technology Baseline ("ATB") document was used to develop cost and performance estimates for generic wind, solar, and battery storage technologies. Information from Xcel Energy's

Engineering and Construction group was used to develop cost and performance estimates for generic gas-fired CC, and gas-fired CT technologies.

The $/MWh LEC of existing wind and solar resources were compared with the LEC of generic wind and solar resources, respectively. The $/MWh LEC of existing coal and gas-fired CC units were compared with two different composites of generic resources. Each generic composite, in aggregate, provides the same amount of generation capacity and energy as that assumed for the existing coal or gas CC unit being assessed. One generic composite was comprised of generic wind, solar, and gas-fired CTs. The other generic composite was comprised of generic wind, solar, and 4-hour batteries.

An effective load carrying capability ("ELCC") credit was applied to all resources (existing and generic) in order to compare the firm MW of existing resources to the generic composites. The ELCC for wind, solar, and battery resources decreases with increased levels of these resources within a composite. This is evident in the wind, solar and battery composite costs for the larger coal and CC units which have higher composite costs relative to composites of smaller MW coal and CC units.

The $/kW-mo LCC of existing gas-fired CTs and pumped storage resources were compared with both generic gas-fired combustion turbines and with generic 4-hour battery storage.

Table 2.5-2 on the following page contains the results of the benchmarking evaluation.

Table 2.5-2 Existing Supply-Side Resource Benchmarking Results

	Rank	Resource	Gen Type	Own/ Purchase	Levelized Cost	Generics Levelized Cost I	Generics Resource Type I	Generics Levelized Cost II	Generics Resource Type II
	BASELOAD RESOURCES ($/MWh)								
	1.	Pawnee 1	Coal	Own	$ 38.39	$ 41.53	COMPOSITE wind & solar with CT	$ 72.15	COMPOSITE wind & solar with battery
	2.	Hayden 1	Coal	Own	$ 39.25	$ 40.79	COMPOSITE wind & solar with CT	$ 54.32	COMPOSITE wind & solar with battery
	3.	Hayden 2	Coal	Own	$ 40.93	$ 40.81	COMPOSITE wind & solar with CT	$ 54.27	COMPOSITE wind & solar with battery
	4.	Craig 2	Coal	Own	$ 45.27	$ 41.03	COMPOSITE wind & solar with CT	$ 54.37	COMPOSITE wind & solar with battery
	5.	Comanche 3	Coal	Own	$ 46.32	$ 41.56	COMPOSITE wind & solar with CT	$ 72.17	COMPOSITE wind & solar with battery
	INTERMEDIATE RESOURCES ($/MWh)								
	1.	Ft. St. Vrain 1,2,3,4	Gas CC	Own	$ 43.55	$ 51.01	COMPOSITE wind & solar with CT	$ 181.69	COMPOSITE wind & solar with battery
	2.	Rocky Mt Energy Center 1,2,3	Gas CC	Own	$ 54.99	$ 51.01	COMPOSITE wind & solar with CT	$ 178.19	COMPOSITE wind & solar with battery
	3.	Arapahoe 5,6,7	Gas CC	Purchase	$ 57.06	$ 50.44	COMPOSITE wind & solar with CT	$ 94.98	COMPOSITE wind & solar with battery
	4.	Cherokee 5,6,7	Gas CC	Own	$ 60.63	$ 51.08	COMPOSITE wind & solar with CT	$ 167.68	COMPOSITE wind & solar with battery
	PEAKING RESOURCES ($/kW-mo)								
	1.	Manchief 11 + 12	Gas CT	Own	$ 1.52	$ 6.97	Generic Combustion Turbine (CT)	$ 26.63	Generic Battery
	2.	Valmont 7 + 8	Gas CT	Own	$ 1.93	$ 6.97	Generic Combustion Turbine (CT)	$ 26.63	Generic Battery
	3.	Ft. Lupton 1 + 2	Gas CT	Own	$ 2.86	$ 6.97	Generic Combustion Turbine (CT)	$ 26.63	Generic Battery
	4.	Brush 1/3	Gas CC	Purchase	$ 5.03	$ 6.97	Generic Combustion Turbine (CT)	$ 26.63	Generic Battery
	5.	Valmont 6	Gas CT	Own	$ 5.62	$ 6.97	Generic Combustion Turbine (CT)	$ 26.63	Generic Battery
	6.	Ft. St. Vrain 5 + 6	Gas CT	Own	$ 5.79	$ 6.97	Generic Combustion Turbine (CT)	$ 26.63	Generic Battery
	7.	Fountain Valley 1-6	Gas CT	Purchase	$ 6.30	$ 6.97	Generic Combustion Turbine (CT)	$ 26.63	Generic Battery
	8.	Brush 4D	Gas CC	Purchase	$ 6.88	$ 6.97	Generic Combustion Turbine (CT)	$ 26.63	Generic Battery
	9.	Spindle Hill	Gas CT	Purchase	$ 7.59	$ 6.97	Generic Combustion Turbine (CT)	$ 26.63	Generic Battery
	10.	Blue Spruce 1 + 2	Gas CT	Own	$ 8.17	$ 6.97	Generic Combustion Turbine (CT)	$ 26.63	Generic Battery
	11.	Plains End II	Gas CT	Purchase	$ 9.25	$ 6.97	Generic Combustion Turbine (CT)	$ 26.63	Generic Battery
	12.	Plains End I	Gas CT	Purchase	$ 9.35	$ 6.97	Generic Combustion Turbine (CT)	$ 26.63	Generic Battery
	13.	Cherokee 4	Gas Steam	Own	$ 9.53	$ 6.97	Generic Combustion Turbine (CT)	$ 26.63	Generic Battery
	PUMPED STORAGE RESOURCES ($/kW-mo)								
	1.	Cabin Creek A + B	Storage	Own	$ 5.76	$ 6.97	Generic Combustion Turbine (CT)	$ 26.63	Generic Battery
	SOLAR RESOURCES ($/MWh)								
	1.	Titan	Solar	Purchase	$ 33.95	$ 26.70	Generic Solar @ 10% ITC		
	2.	Hooper	Solar	Purchase	$ 59.90	$ 26.70	Generic Solar @ 10% ITC		
	3.	Comanche	Solar	Purchase	$ 62.50	$ 26.70	Generic Solar @ 10% ITC		
	4.	San Luis	Solar	Purchase	$ 138.25	$ 26.70	Generic Solar @ 10% ITC		
	5.	KEPCO Alamosa	Solar	Purchase	$ 143.01	$ 26.70	Generic Solar @ 10% ITC		
	WIND RESOURCES ($/MWh)								
	1.	Bronco Plains	Wind	Purchase	$ 10.68	$ 29.15	Generic Wind @ 0% PTC		
	2.	Colorado Green	Wind	Purchase	$ 14.16	$ 29.15	Generic Wind @ 0% PTC		
	3.	Mountain Breeze	Wind	Purchase	$ 18.00	$ 29.15	Generic Wind @ 0% PTC		
	4.	Ridge Crest	Wind	Purchase	$ 20.00	$ 29.15	Generic Wind @ 0% PTC		
(1)	5.	Cheyenne Ridge	Wind	Own	$ 20.61	$ 29.15	Generic Wind @ 0% PTC		
	6.	Rush Creek I + II	Wind	Own	$ 28.68	$ 29.15	Generic Wind @ 0% PTC		
	7.	Limon III	Wind	Purchase	$ 31.13	$ 29.15	Generic Wind @ 0% PTC		
	8.	Golden West	Wind	Purchase	$ 36.10	$ 29.15	Generic Wind @ 0% PTC		
	9.	Spring Canyon	Wind	Purchase	$ 37.79	$ 29.15	Generic Wind @ 0% PTC		
	10.	Limon I	Wind	Purchase	$ 38.71	$ 29.15	Generic Wind @ 0% PTC		
	11.	Limon II	Wind	Purchase	$ 40.38	$ 29.15	Generic Wind @ 0% PTC		
	12.	Cedar Creek	Wind	Purchase	$ 48.75	$ 29.15	Generic Wind @ 0% PTC		
	13.	Twin Buttes	Wind	Purchase	$ 53.39	$ 29.15	Generic Wind @ 0% PTC		
	14.	Logan	Wind	Purchase	$ 54.49	$ 29.15	Generic Wind @ 0% PTC		
	15.	Peetz Table	Wind	Purchase	$ 56.69	$ 29.15	Generic Wind @ 0% PTC		
	16.	Cedar Point	Wind	Purchase	$ 59.00	$ 29.15	Generic Wind @ 0% PTC		
	17.	Northern Colorado I	Wind	Purchase	$ 68.08	$ 29.15	Generic Wind @ 0% PTC		
	18.	Northern Colorado II	Wind	Purchase	$ 69.70	$ 29.15	Generic Wind @ 0% PTC		
	19.	Cedar Creek II	Wind	Purchase	$ 72.50	$ 29.15	Generic Wind @ 0% PTC		
	GENERIC RESOURCES			**Levelized Units**					
	-	Generic CT		$/kW-mo	$ 6.97				
	-	Generic Battery		$/kW-mo	$ 26.63				
	-	Generic Solar		$/MWh	$ 26.70				
	-	Generic Wind		$/MWh	$ 29.15				
	-	Generic CC		$/MWh	$ 59.76				

(1) Cheyenne Ridge includes approximately $4 of deferred tax asset costs.

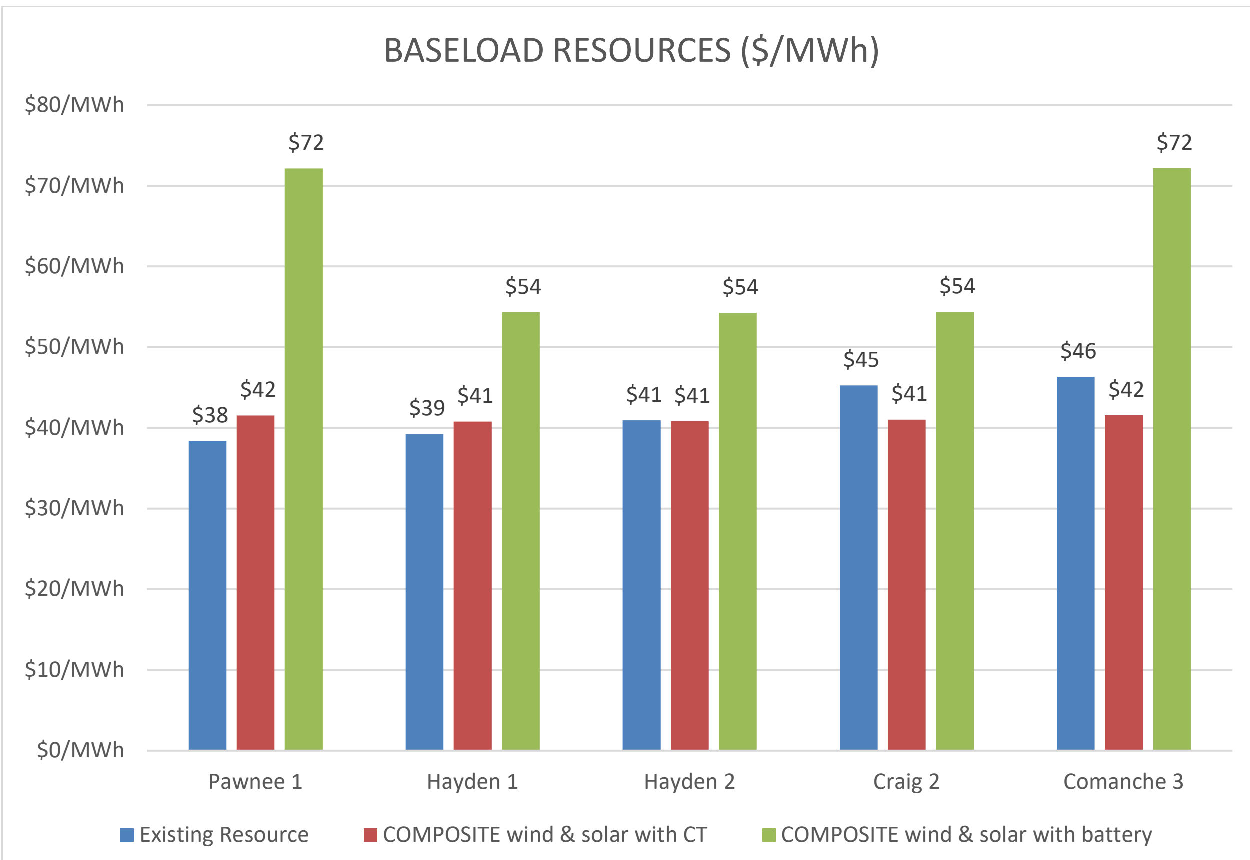
Results Discussion with $0/ton CO_2 Cost

Baseload Resources

The baseload resources include all Company-owned coal units. The 505 MW Pawnee unit has the lowest LEC at $38/MWh. Pawnee's LEC is 8% lower cost than the composite with CTs and 47% lower than the composite with 4-hour batteries. The Comanche 3 LEC is 11% higher than the composite with CTs and 35% lower cost than the composite with 4-hour batteries. The LECs of Hayden units and Craig 2 lie in between.

Figure 2.5-1 contains the results of the baseload resources analysis.

Figure 2.5-1 Existing Baseload Resources and Composite Results

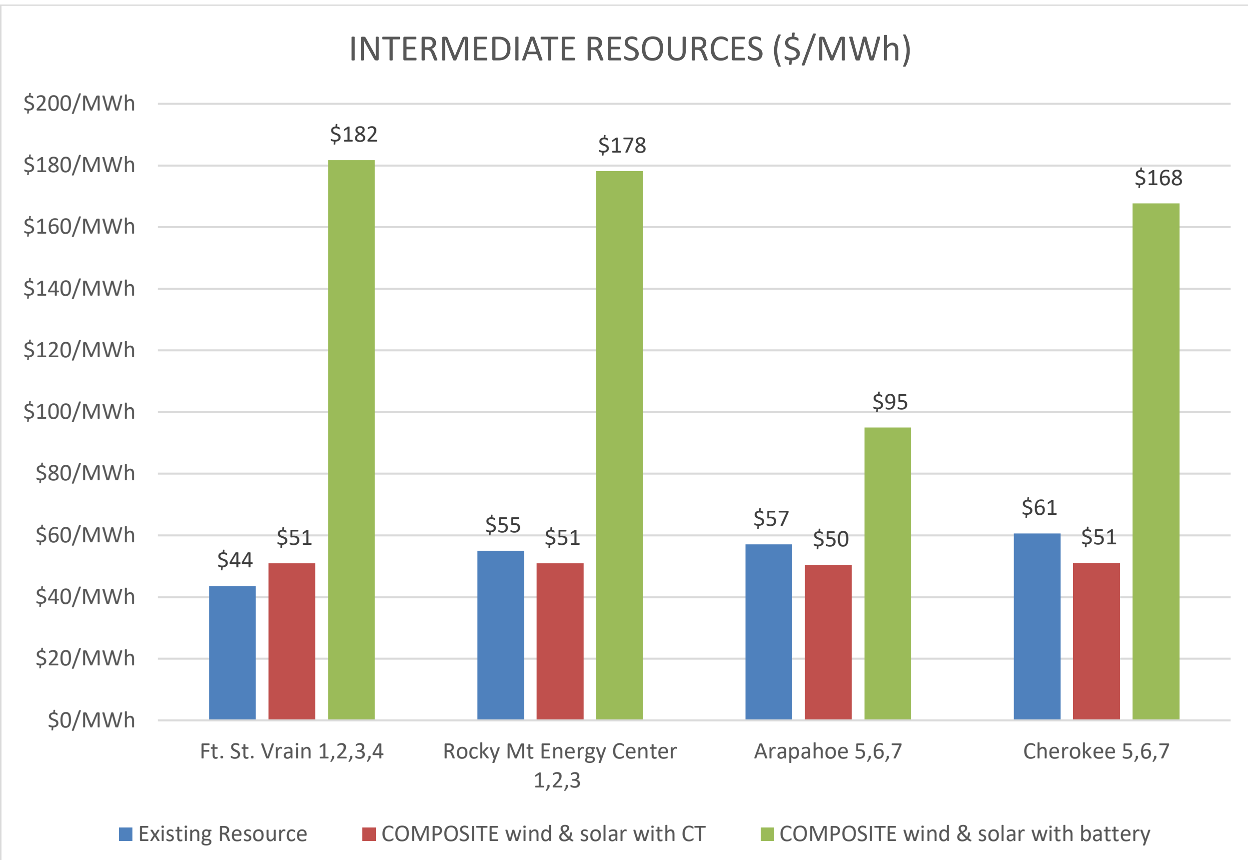


Intermediate Resources

Intermediate resources include three Company-owned units, and one PPA. Ft. St. Vrain 1,2,3,4 ("FSV") has the lowest LEC at $44/MWh, 15% lower cost than the composite with CTs and 76% lower than the composite with 4-hour batteries. The LEC of Cherokee 5,6,7 is 19% higher than the composite with CTs and 64% lower than the composite with 4-hour batteries. Rocky Mountain Energy Center and Arapaho 5,6,7 fall in between. All CC units appear cost effective versus the generic composites.

Figure 2.5-2 contains the results of the intermediate resources analysis.

Figure 2.5-2 Existing Intermediate Resources and Composite Results



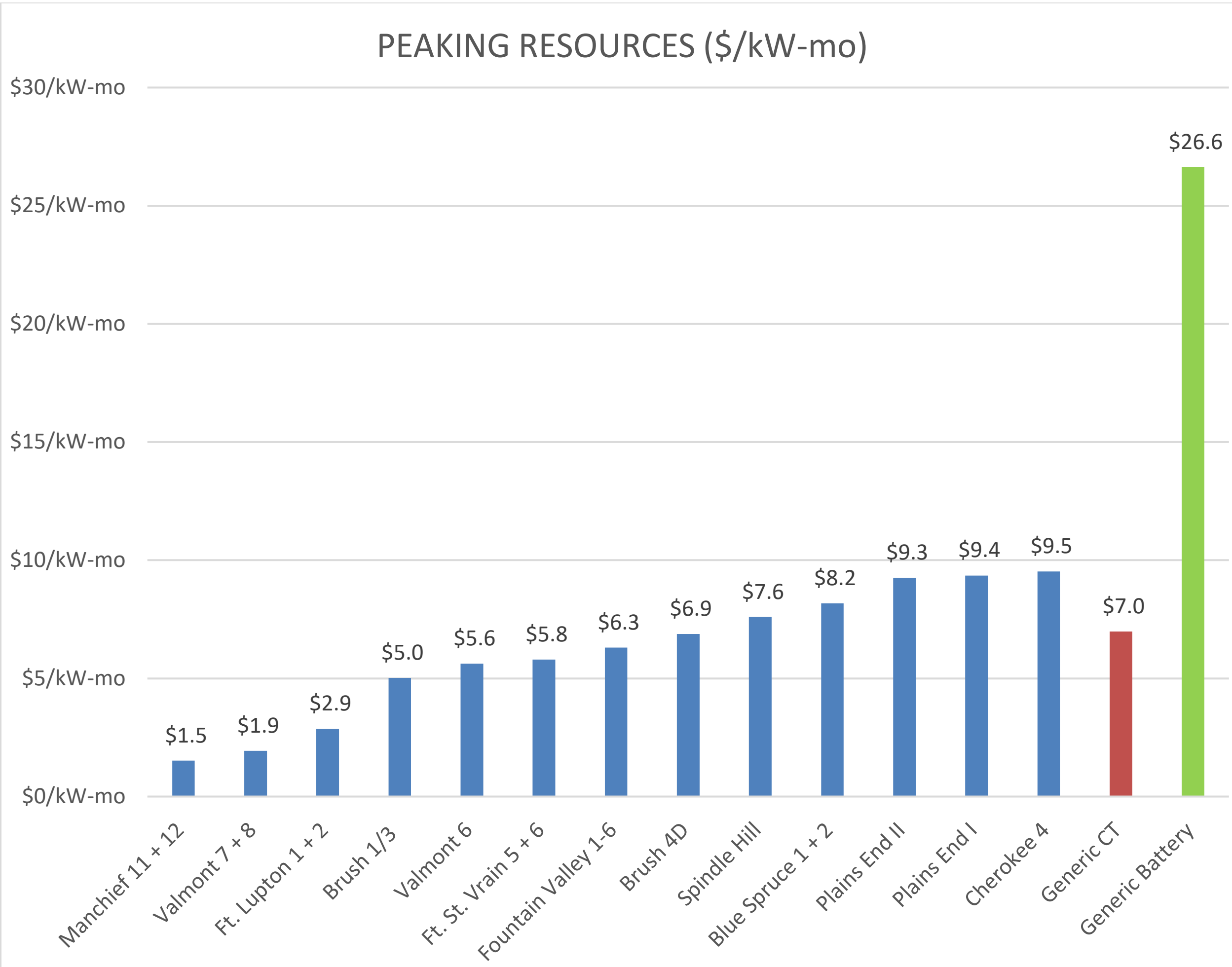
Peaking Resources

The existing resources represented as peaking resources include gas steam (Cherokee 4), gas combustion turbines, and a gas CC unit. The Brush 4D gas CC unit is included as a peaking resource given its high heat rate results in the unit being dispatched in a peaking role. Manchief 11 + 12 has the lowest LCC at $1.53/kW-mo and is 78% and

94% lower cost than the generic CT and 4-hour battery, respectively. The LEC of Cherokee 4 at $9.53/kW-mo, is 37% higher than the generic CT and 64% lower than the generic 4-hour battery. The remaining peaking resources fall in between.

Figure 2.5-3 contains the results of the peaking resources analysis.

Figure 2.5-3 Existing Peaking Resources and Generics Results

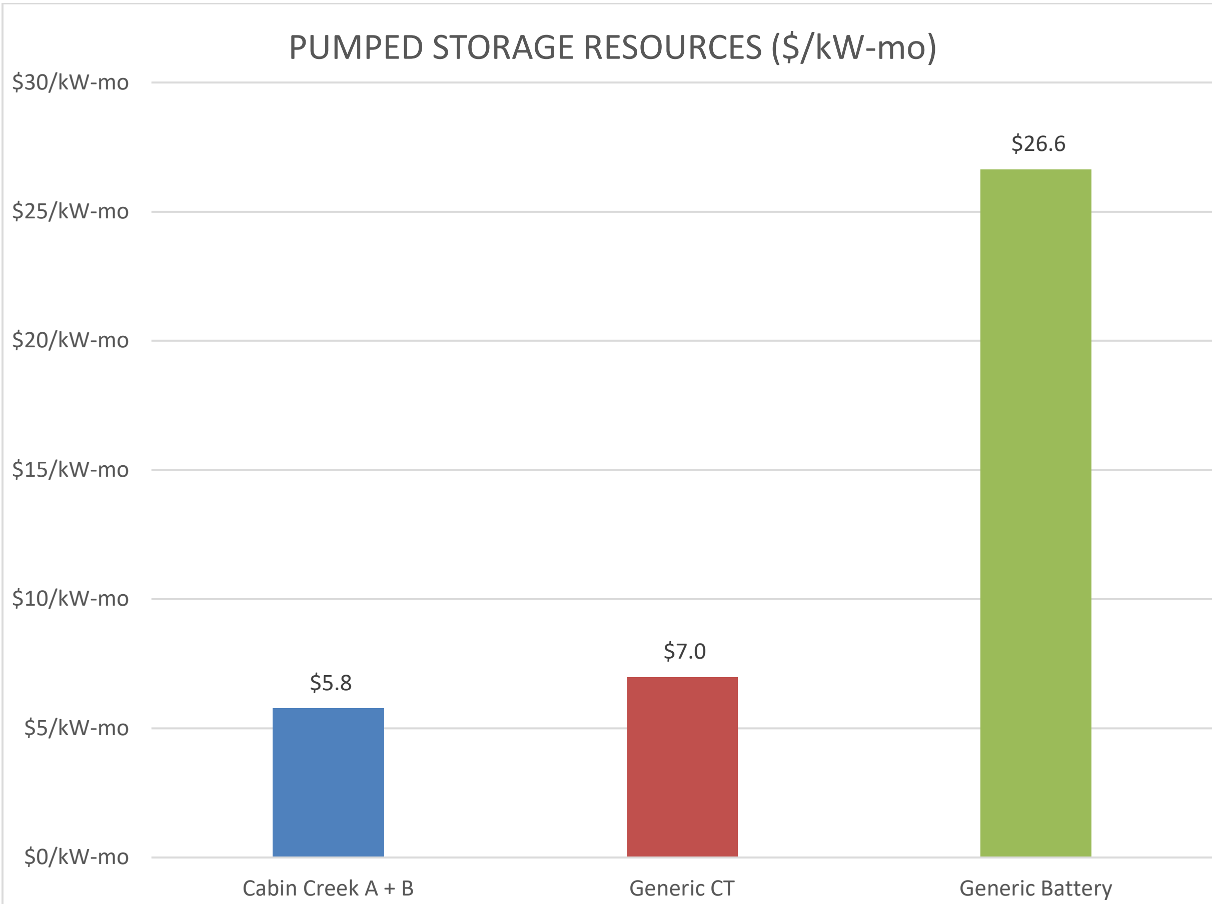


<u>Pumped Storage Resources</u>

Cabin Creek is the Company's only pumped storage resource with an LCC of $6/kW-mo, which is 17% and 78% lower than the generic CT and 4-hour battery, respectively.

Figure 2.5-4 contains the results of the pumped storage resources analysis.

Figure 2.5-4 Existing Pumped Storage Resource and Generics Results

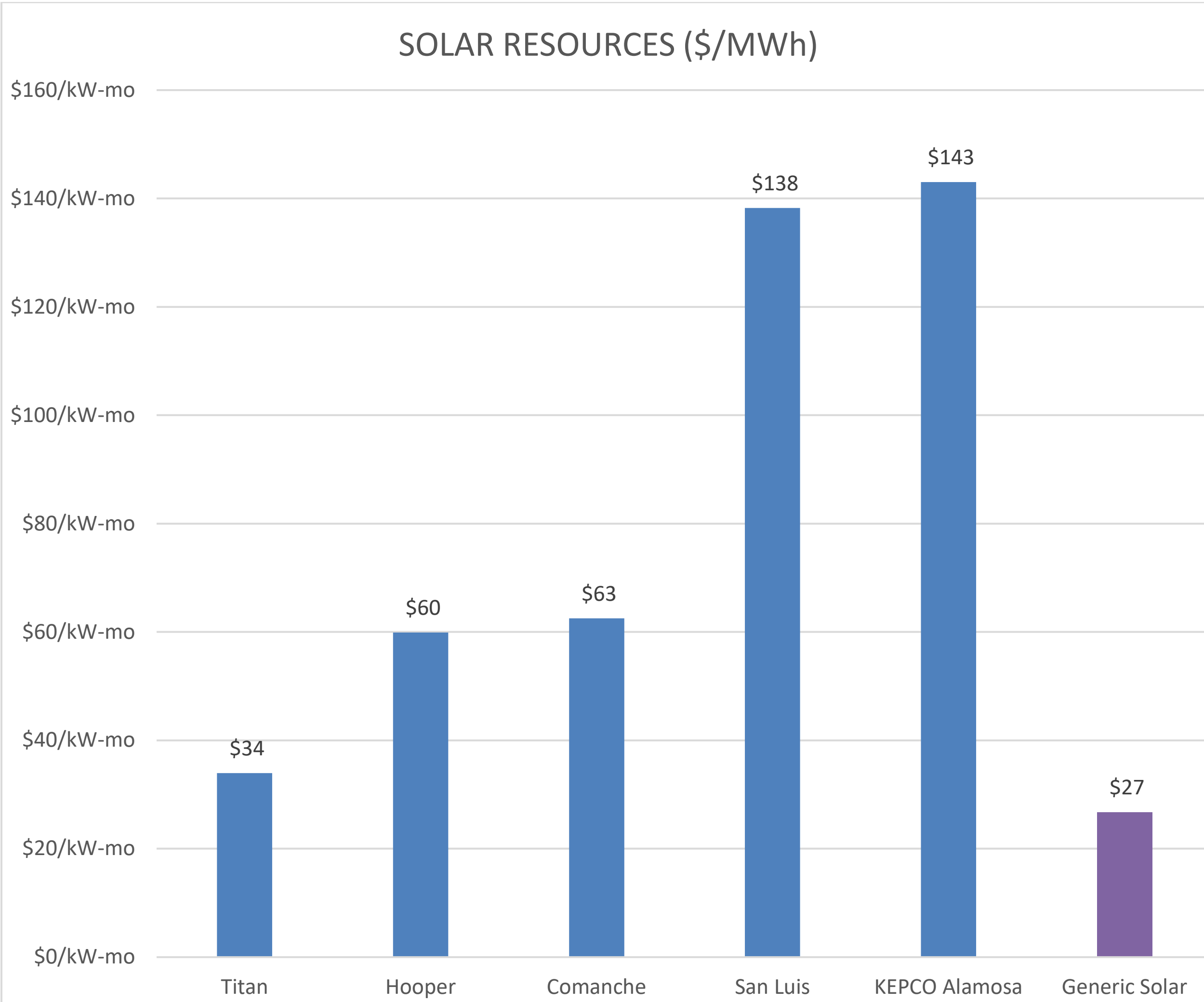


<u>Solar Resources</u>

The lowest-cost existing solar resource is the 50 MW Titan facility at an LEC of $34/MWh, which is 27% higher cost than that of generic solar. KEPCO Alamosa is the oldest solar unit in the benchmarking analysis at an LEC of $143/MWh, which is 435% higher than that of generic solar.

Figure 2.5-5 contains the results of the solar resources analysis.

Figure 2.5-5 Existing Solar Resources and Generics Results

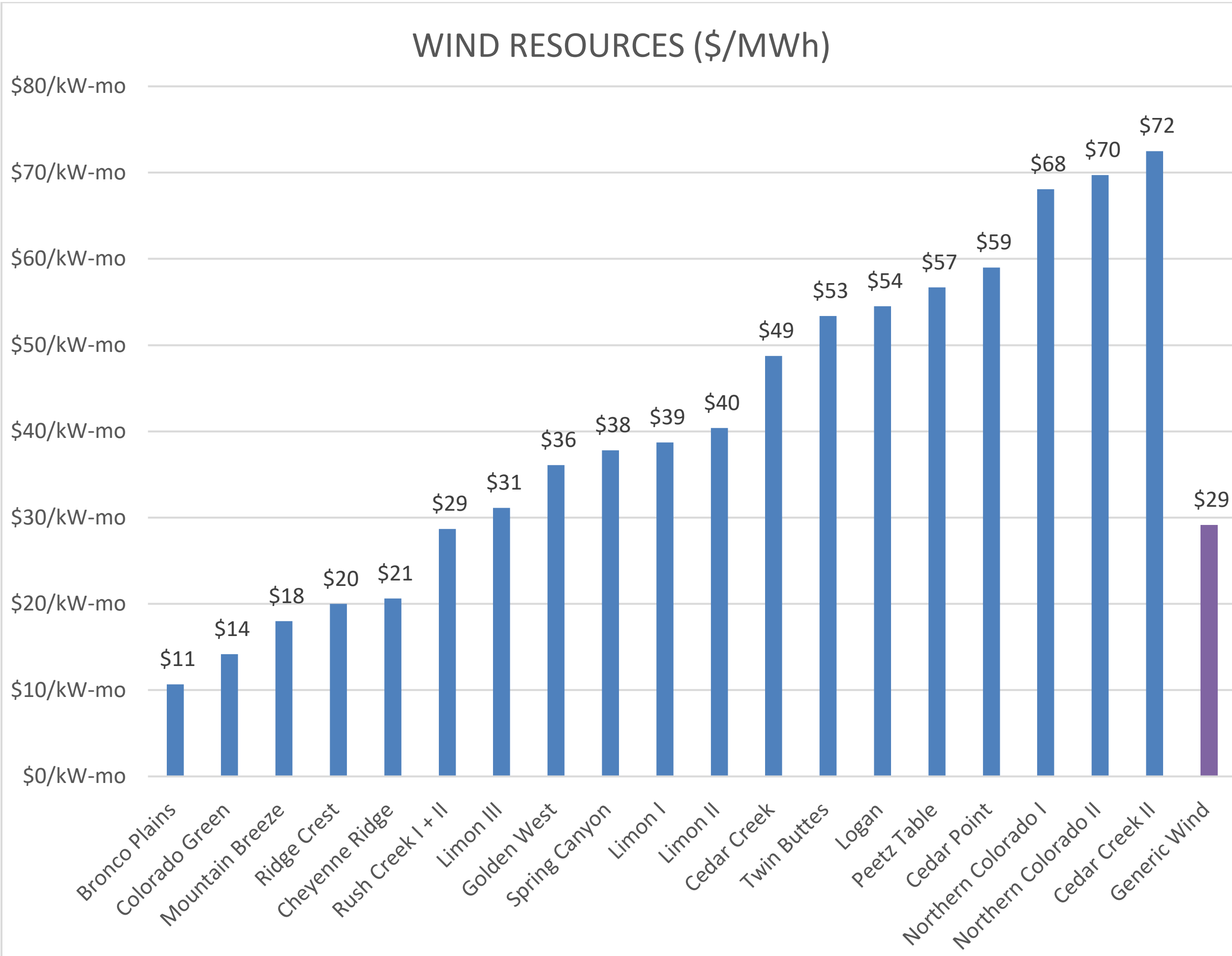


<u>Wind Resources</u>

The Bronco Plains facility has the lowest-ranked LEC at $11/MWh, 63% lower than that of generic wind. Cedar Creek II has an LEC of $73/MWh, 149% higher than the generic wind.

Figure 2.5-6 contains the results of the wind resources analysis.

Figure 2.5-6 Existing Wind Resources and Generics Results



<u>Results Discussion with CO_2 Cost at Social Cost of Carbon</u>

Existing baseload and intermediate resources were also benchmarked with the social cost of carbon ("SCC") reflected in Figure 2.5-7 embedded within the LECs. The results of the benchmarking evaluation with the SCC are provided in Table 2.5-3. Given that peaking resources were represented in the benchmarking on an LCC basis which is capacity focused, the peaking resources were not represented in the benchmarking with a SCC applied to their LCC.

Figure 2.5-7 Social Cost of Carbon ($ per short-ton)

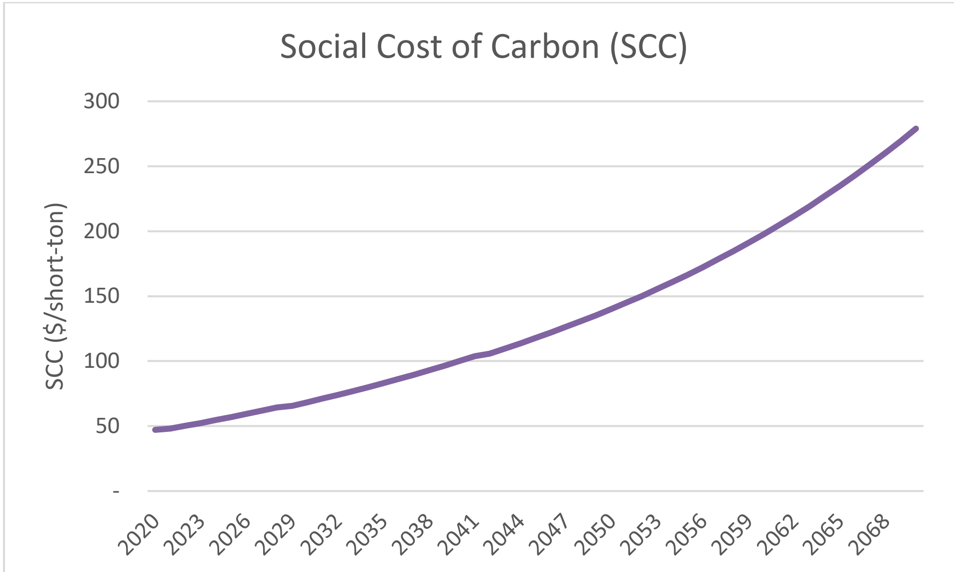


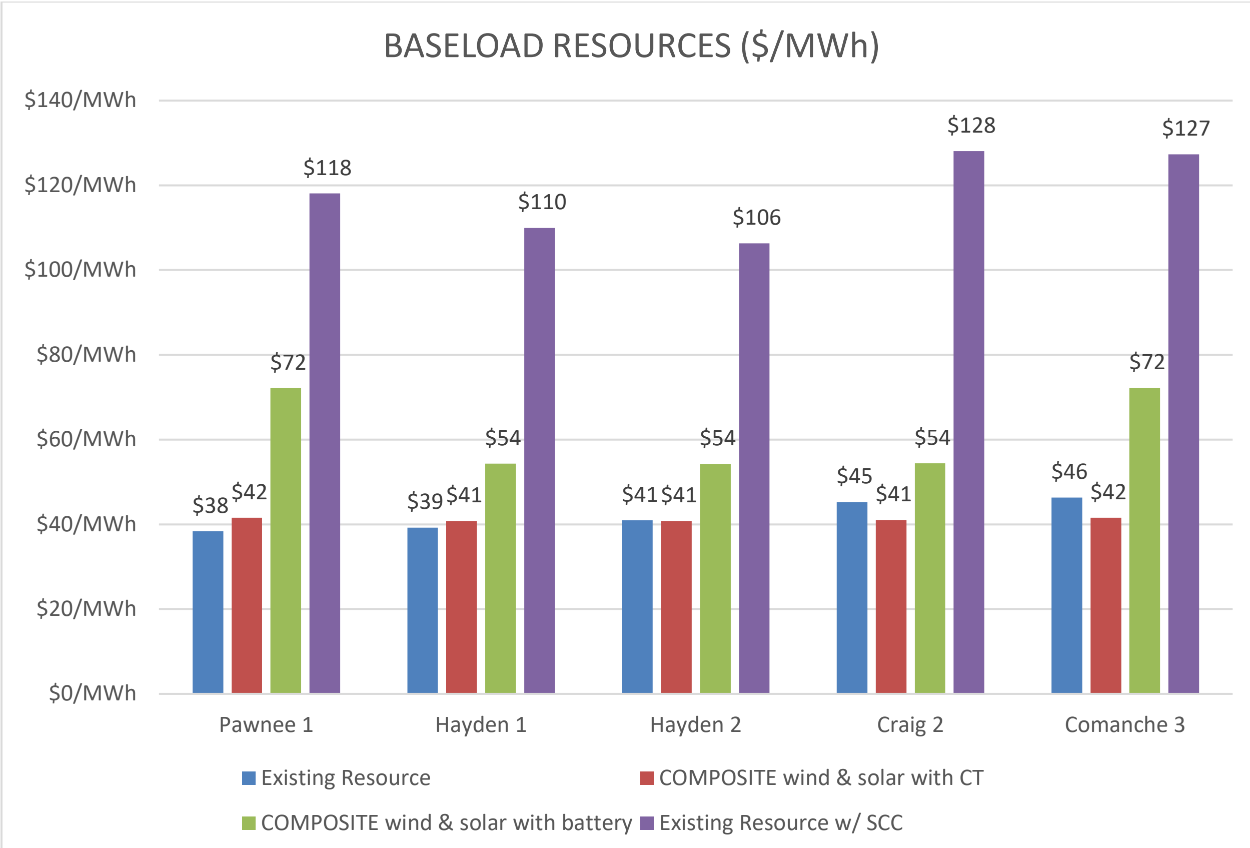
Table 2.5-3 Existing Supply-Side Resource Benchmarking Results with the Social Cost of Carbon

Rank	Resource	Gen Type	Own/ Purchase	Levelized Cost w/ SCC	Generics Levelized Cost I	Generics Resource Type I	Generics Levelized Cost II	Generics Resource Type II
BASELOAD RESOURCES ($/MWh)								
1.	Hayden 2	Coal	Own	$ 106.34	$ 40.81	COMPOSITE wind & solar with CT	$ 54.27	COMPOSITE wind & solar with battery
2.	Hayden 1	Coal	Own	$ 109.96	$ 40.79	COMPOSITE wind & solar with CT	$ 54.32	COMPOSITE wind & solar with battery
3.	Pawnee 1	Coal	Own	$ 118.06	$ 41.53	COMPOSITE wind & solar with CT	$ 72.15	COMPOSITE wind & solar with battery
4.	Craig 2	Coal	Own	$ 128.06	$ 41.03	COMPOSITE wind & solar with CT	$ 54.37	COMPOSITE wind & solar with battery
5.	Comanche 3	Coal	Own	$ 127.33	$ 41.56	COMPOSITE wind & solar with CT	$ 72.17	COMPOSITE wind & solar with battery
INTERMEDIATE RESOURCES ($/MWh)								
1.	Ft. St. Vrain 1,2,3,4	Gas CC	Own	$ 72.88	$ 51.01	COMPOSITE wind & solar with CT	$ 181.69	COMPOSITE wind & solar with battery
2.	Arapahoe 5,6,7	Gas CC	Purchase	$ 81.78	$ 50.44	COMPOSITE wind & solar with CT	$ 94.98	COMPOSITE wind & solar with battery
3.	Rocky Mt Energy Center 1,2,3	Gas CC	Own	$ 85.90	$ 51.01	COMPOSITE wind & solar with CT	$ 178.19	COMPOSITE wind & solar with battery
4.	Cherokee 5,6,7	Gas CC	Own	$ 90.42	$ 51.08	COMPOSITE wind & solar with CT	$ 167.68	COMPOSITE wind & solar with battery
GENERIC RESOURCES			**Levelized Units**					
-	Generic CC		$/MWh	$ 97.33				

Baseload Resources:

Hayden 2 unit has the lowest LEC at $106/MWh, 161% and 96% higher than the composite with CTs and the composite with 4-hour batteries respectively. The LEC of Comanche 3 is 206% and 76% higher than the composite with CTs and the composite with 4-hour batteries respectively. A SCC cost adder was not applied to the representation of composites with CTs or 4-hour batteries. Figure 2.5-8 contains the results of the baseload resources analysis.

Figure 2.5-8 Existing Baseload Resources with and Without SCC and Composite Results

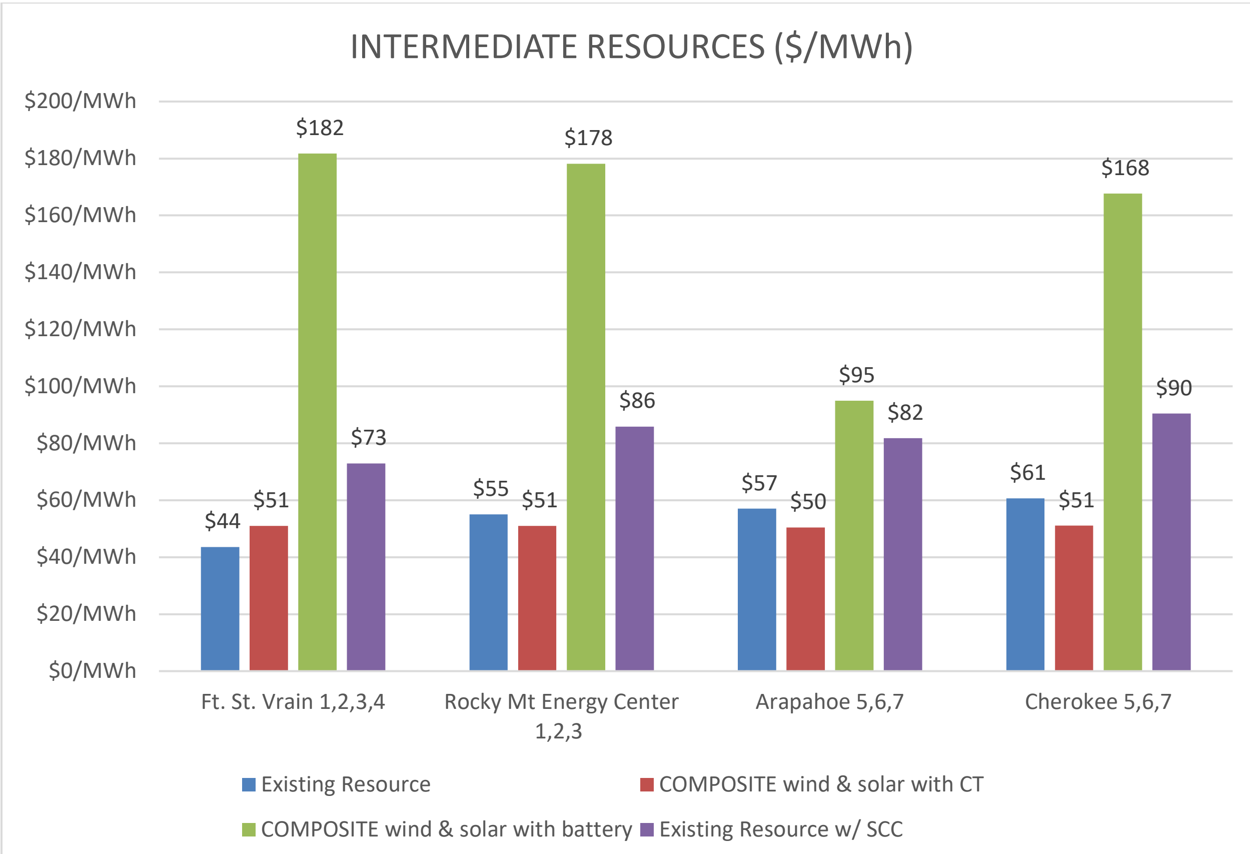


<u>Intermediate Resources:</u>

With the SCC adder, FSV shows the lowest LEC at $73/MWh, 43% higher than the composite with CTs and 60% lower than the composite with 4-hour batteries. Cherokee 5,6,7 at $90.42/MWh is 77% higher cost than the composite with CTs and 45% lower cost than the composite with 4-hour batteries. Again, both type of composites have no SCC adder due to the resource types within the composites.

Figure 2.5-9 contains the results of the intermediate resources analysis.

Figure 2.5-9 Existing Intermediate Resources with and Without SCC and Composite Results



Expanded Methodology Discussion

The LEC and LCC calculations were performed by taking the unit inputs, calculating the annual unit operating costs, and annualizing the costs over the remaining resource asset life or PPA term (shown as the "Summer Expiration Year"). All inputs in the calculations are broken down by resource and ownership type in the Tables 2.5-4 through 2.5-8 below.

Next, the NPV of the total annual costs was divided by the NPV of the annual energy over the remaining resource asset life or PPA term for the LEC calculation (baseload, intermediate, solar, and wind resources). For the LCC calculation (peaking and pumped storage resources), annual costs were divided by the unit's capacity and then by 12 to get the cost per capacity per month ($/kW-mo), and the annual costs of this result were then calculated back to the present NPV.

The Company's current discount rate of 7.04% was used for all NPV calculations, and the period included from 2020 to the unit's Summer Expiration Year. Thermal resources (baseload and intermediate) were given a static capacity factor to level the evaluation since numerous inputs control how often these units run. Renewable resources (solar and wind) used a historical average to determine the capacity factors, given how often these units are run is dependent on location and weather.

Table 2.5-4 contains the inputs and calculations of the baseload resources.

Table 2.5-4 Baseload Resources Inputs and Calculations

BASELOAD RESOURCES ($/MWh)		
OWNED UNITS		PURCHASED UNITS
Summer Expiration Year		n/a
Nameplate Capacity (MW)	A	
Capacity Factor (%)	B	
Annual Energy (GWh)	C = A * B * 8.76	
Heat Rate (btu/kWh)	D	
Fuel Price ($/MMbtu)	E	
Variable O&M Rate ($/MWh)	F	
Revenue Requirements ($M)	G	
Fixed O&M Costs ($M)	H	
Variable O&M Costs ($M)	I = C * F / 1000	
Fuel Costs ($M)	J = C * D * E /1E6	
Total Annual Costs ($M)	K = G + H + I + J	
LEC ($/MWh)	**L = K * 1000 / C**	
SCC ($/short-ton)	M	
SCC ($/lb)	N = M / 2000	
CO2 Emissions (lb/MWh)	O	
CO2 Emission Rate ($/MWh)	P = N * O	
SCC Cost ($M)	Q = C * P	
LEC w/ SCC ($/MWh)	**R = (Q * 1000 / C) + L**	
		blue = input / black = calculation

Table 2.5-5 contains the inputs and calculations of the intermediate resources.

Table 2.5-5 Intermediate Resources Inputs and Calculations

INTERMEDIATE RESOURCES ($/MWh)			
OWNED UNITS		PURCHASED UNITS	
Summer Expiration Year		Summer Expiration Year	
		PPAs CAF (%)	A
Nameplate Capacity (MW)	A	PPAs DAF (%)	B
Capacity Factor (%)	B		
Annual Energy (GWh)	C = A * B * 8.76	Nameplate Capacity (MW)	C
		Capacity Factor (%)	D
Heat Rate (btu/kWh)	D	Annual Energy (GWh)	E = C * D * 8.76
Fuel Price ($/MMbtu)	E		
Variable O&M Rate ($/MWh)	F	Heat Rate (btu/kWh)	F
		Fuel Price ($/MMbtu)	G
Revenue Requirements ($M)	G	Capacity Rate ($/kW-mo)	H
Fixed O&M Costs ($M)	H	Dispatchability ($/kW-mo)	I
Gas Demand Charge ($M)	I	Tolling ($/MWh)	J
Variable O&M Costs ($M)	J = C * F / 1000		
Fuel Costs ($M)	K = C * D * E / 1E6	Gas Demand Charge ($M)	K
Total Annual Costs ($M)	L = G + H + I + J + K	Fixed Costs ($M)	L = (A * H + B * I) * C * 12 / 1000
		Variable Costs ($M)	M = E * J / 1000
LEC ($/MWh)	**M = L * 1000 / C**	Fuel Costs ($M)	N = E * F * G / 1E6
		Total Annual Costs ($M)	O = K + L + M + N
SCC ($/short-ton)	N		
SCC ($/lb)	O = N / 2000	**LEC ($/MWh)**	**P = O * 1000 / E**
CO2 Emissions (lb/MMBtu)	P		
($/MMbtu)	Q = O * P	SCC ($/short-ton)	Q
CO2 Emission Rate ($/MWh)	R = D * Q / 1000	SCC ($/lb)	R = Q / 2000
SCC Cost ($M)	S = C * R / 1000	CO2 Emissions (lb/MMBtu)	S
		($/MMbtu)	T = R * S
LEC w/ SCC ($/MWh)	**T = (S * 1000 / C) + M**	CO2 Emission Rate ($/MWh)	U = F * T / 1000
		SCC Cost ($M)	V = E * U / 1000
		LEC w/ SCC ($/MWh)	**W = (V * 1000/ E) + O**
blue = input / black = calculation			

Table 2.5-6 contains the inputs and calculations of the peaking resources.

Table 2.5-6 Peaking Resources Inputs and Calculations

PEAKING RESOURCES ($/kW-mo)			
OWNED UNITS		PURCHASED UNITS	
Summer Expiration Year		Summer Expiration Year	
Nameplate Capacity (MW)	A	PPAs CAF (%)	A
		PPAs DAF (%)	B
Revenue Requirements ($M)	B	Nameplate Capacity (MW)	C
Fixed O&M Costs ($M)	C	Capacity Rate ($/kW-mo)	D
Gas Demand Charge ($M)	D	Dispatchability ($/kW-mo)	E
Total Annual Costs ($M)	E = B + C + D		
		Gas Demand Charge ($M)	F
LCC ($/kW-mo)	**F = E * 1000 / A / 12**	Capacity Costs ($M)	G = A * C * D * 12 / 1000
		Dispatchability ($M)	H = B * C * D * 12 / 1000
		Total Annual Costs ($M)	I = F + G + H
		LCC ($/kW-mo)	**J = I * 1000 / C / 12**
blue = input / black = calculation			

Table 2.5-7 contains the inputs and calculations of the pumped storage resources.

Table 2.5-7 Pumped Storage Resources Inputs and Calculations

PUMPED STORAGE RESOURCES ($/kW-mo)		
OWNED UNITS		PURCHASED UNITS
Summer Expiration Year		n/a
ELCC (%)	A	
Nameplate Capacity (MW)	B	
Revenue Requirements ($M)	B	
Fixed O&M Costs ($M)	C	
Total Annual Costs ($M)	D = B + C	
LCC ($/kW-mo)	**F = E * 1000 / B / 12 / A**	
		blue = input / black = calculation

Table 2.5-8 contains the inputs and calculations of the solar and wind resources.

Table 2.5-8 Solar and Wind Resources Inputs and Calculations

SOLAR & WIND RESOURCES ($/MWh)			
OWNED UNITS		PURCHASED UNITS	
LEC ($/MWh)	**CPCN**	Summer Expiration Year	
		Nameplate Capacity (MW)	A
		Capacity Factor (%)	B
		Annual Energy (GWh)	C = A * B * 8.76
		Energy Payment Rate ($/MWh)	D
		Total Annual Costs ($M)	E = C * D / 1000
		LEC ($/MWh)	**F = E * 1000 / C**
blue = input / black = calculation			

Table 2.5-9 contains the sources of all inputs for owned resources.

Table 2.5-9 Owned Resources Sources of Inputs

OWNED UNITS		
Input	Source	Note
Summer Expiration Year	L&R / Energy Supply	Last summer the plant is available.
Nameplate Capacity (MW)	L&R / Energy Supply	Average of summer and winter net dependable capacity.
Capacity Factor (%)	Resource Planning	Static value for thermal units.
Heat Rate (btu/kWh)	Energy Supply tests	Average of summer, winter, and spring/fall net unit heat rate.
Fuel Price ($/MMbtu)	Risk Management / Fuel Supply forecast	
Variable O&M Rate ($/MWh)	Energy Supply forecast	
Revenue Requirements ($M)	Revenue Requirements' model	With Energy Supply's On-Going Capital Expenditures forecast.
Fixed O&M Costs ($M)	Energy Supply forecast	
SCC ($/short-ton)	Regulatory	
CO2 Emissions (lb/MWh)	Energy Supply tests	
Gas Demand Charge ($M)	Gas Planning forecast	
CO2 Emissions (lb/MMBtu)	Energy Supply tests	
ELCC (%)	Resource Planning ELCC study	

Table 2.5-10 contains the sources of all inputs for purchased resources.

Table 2.5-10 Purchased Resources Sources of Inputs

PURCHASED UNITS		
Input	Source	Note
Summer Expiration Year	L&R / Purchase Power contracts	Last summer the plant is available.
PPAs CAF (%)	Purchase Power contracts	
PPAs DAF (%)	Purchase Power contracts	
Nameplate Capacity (MW)	L&R / Purchase Power contracts	Contracted capacity.
Capacity Factor (%)	Purchase Power	Static value for thermal units, historical average for renewables.
Heat Rate (btu/kWh)	Energy Supply / Purchase Power	Average of summer, winter, and spring/fall net unit heat rate.
Fuel Price ($/MMbtu)	Risk Management / Fuel Supply forecast	
Capacity Rate ($/kW-mo)	Purchase Power contracts	
Dispatchability ($/kW-mo)	Purchase Power contracts	
Tolling ($/MWh)	Purchase Power contracts	
Gas Demand Charge ($M)	Gas Planning forecast	
SCC ($/short-ton)	Regulatory	
CO2 Emissions (lb/MMBtu)	Energy Supply / Purchase Power	
Energy Payment Rate ($/MWh)	Purchase Power contracts	

Comparison of Historical Costs with Projected Costs

Figures 2.5-10 through 2.5-22 below provide graphical illustrations of how historical costs for the Company’s owned units align with the forecasted costs for those same units that were utilized in the benchmarking analysis.

Figure 2.5-10 shows the historical (solid line) and forecasted (dashed line) Ongoing Capital Expenditures ("CapEx") for baseload resources.

Figure 2.5-10 Baseload Resources Historical and Forecasted Ongoing CapEx

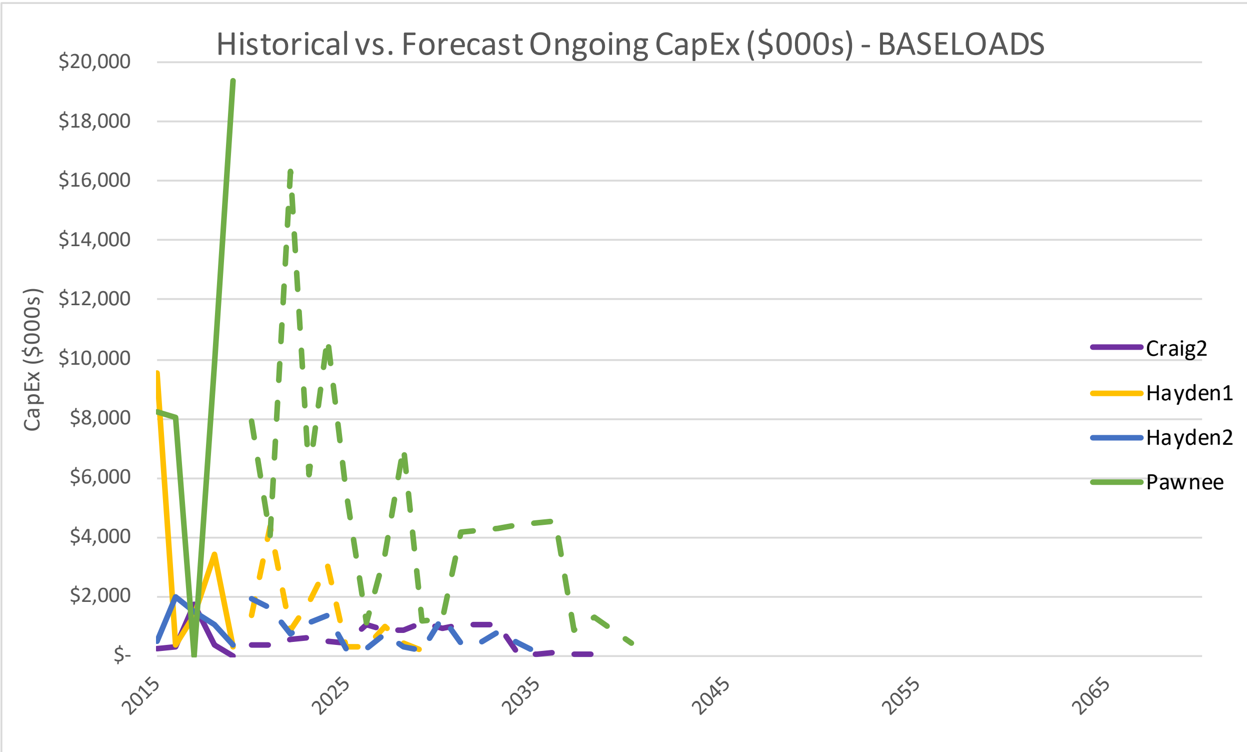


Figure 2.5-11 shows the historical (solid line) and forecasted (dashed line) CapEx for Comanche 3.

Figure 2.5-11 Comanche 3 Historical and Forecasted Ongoing CapEx

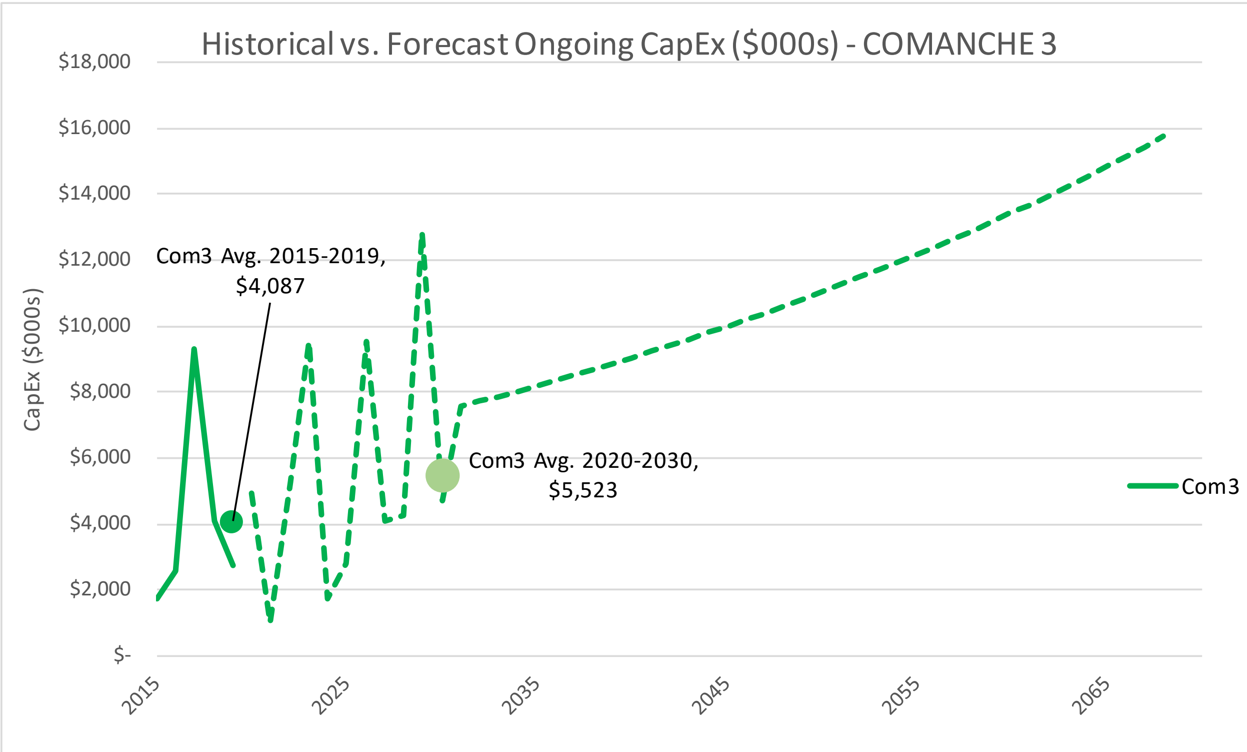


Figure 2.5-12 shows the historical (solid line) and forecasted (dashed line) CapEx for intermediate resources.

Figure 2.5-12 Intermediate Resources Historical and Forecasted Ongoing CapEx

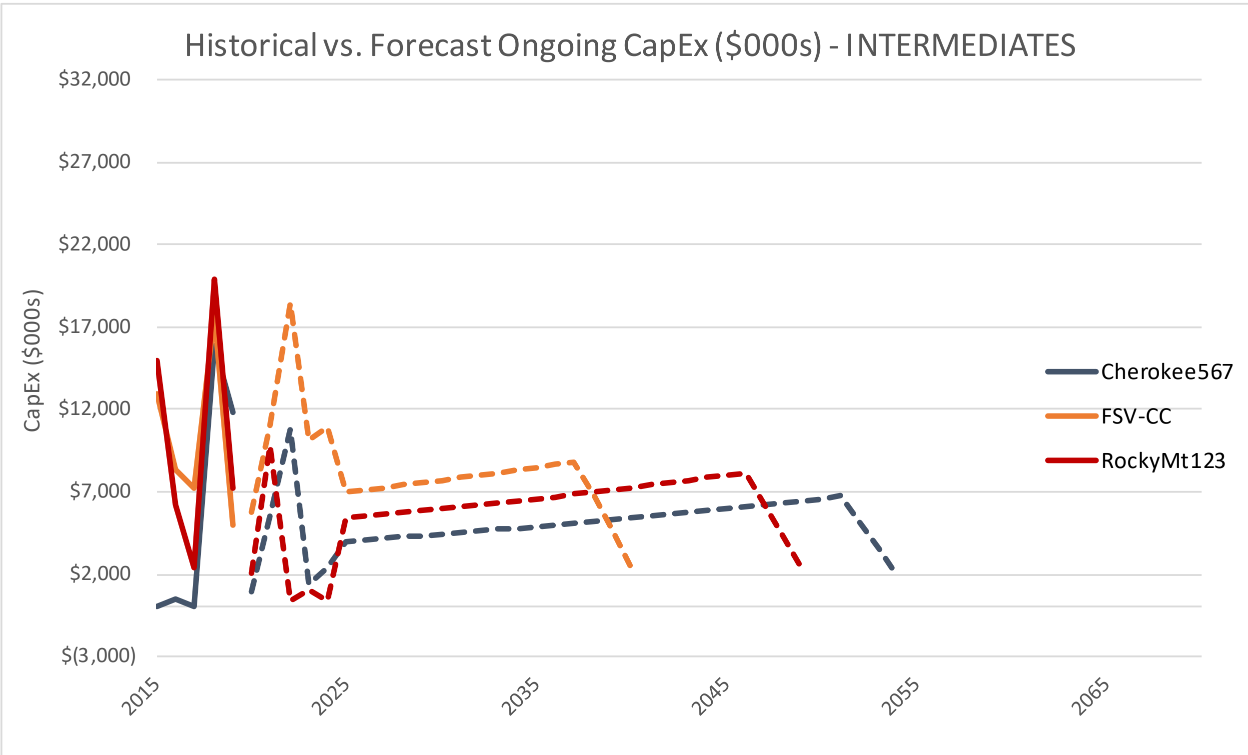


Figure 2.5-13 shows the historical (solid line) and forecasted (dashed line) CapEx for peaking resources.

Figure 2.5-13 Peaking Resources Historical and Forecasted Ongoing CapEx

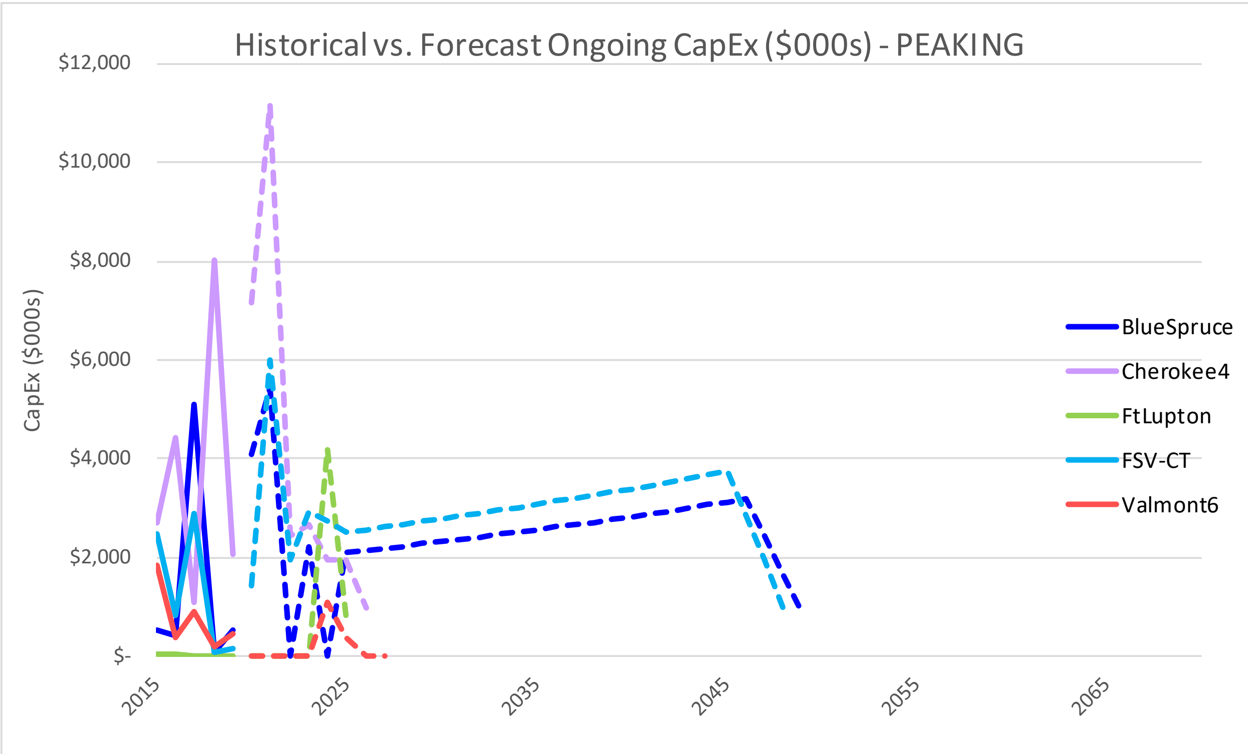


Figure 2.5-14 shows the historical (solid line) and forecasted (dashed line) CapEx for pumped storage resources.

Figure 2.5-14 Pumped Storage Resources Historical and Forecasted Ongoing CapEx

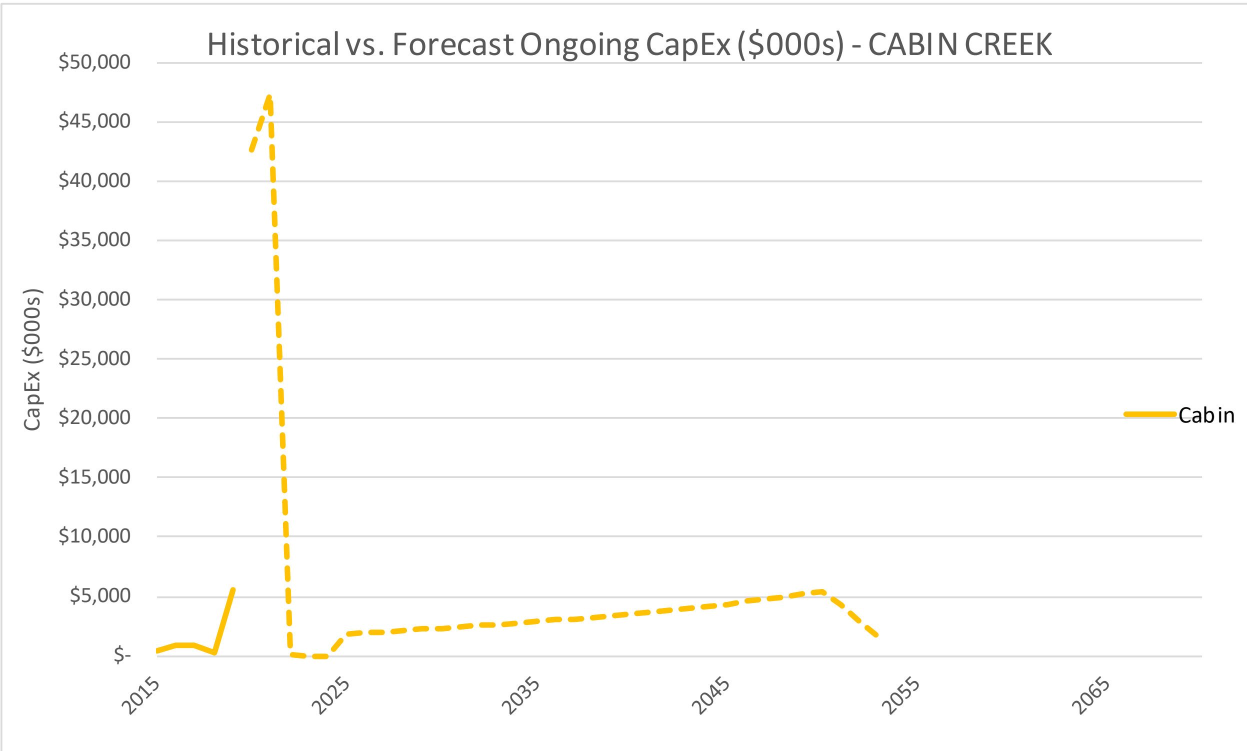


Figure 2.5-15 shows the historical (solid line) and forecasted (dashed line) fixed operations and maintenance ("O&M") costs for baseload resources.

Figure 2.5-15 Baseload Resources Historical and Forecasted Fixed O&M

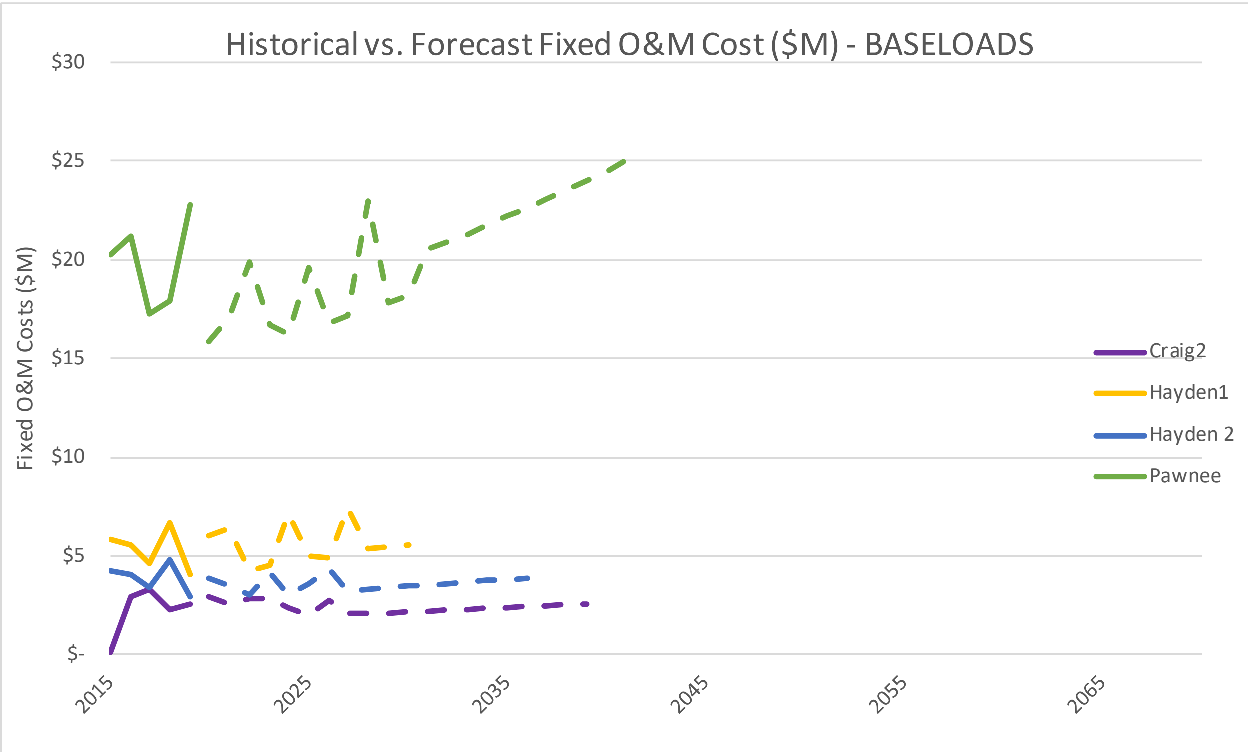


Figure 2.5-16 shows the historical (solid line) and forecasted (dashed line) fixed O&M costs for Comanche 3.

Figure 2.5-16 Comanche 3 Historical and Forecasted Fixed O&M

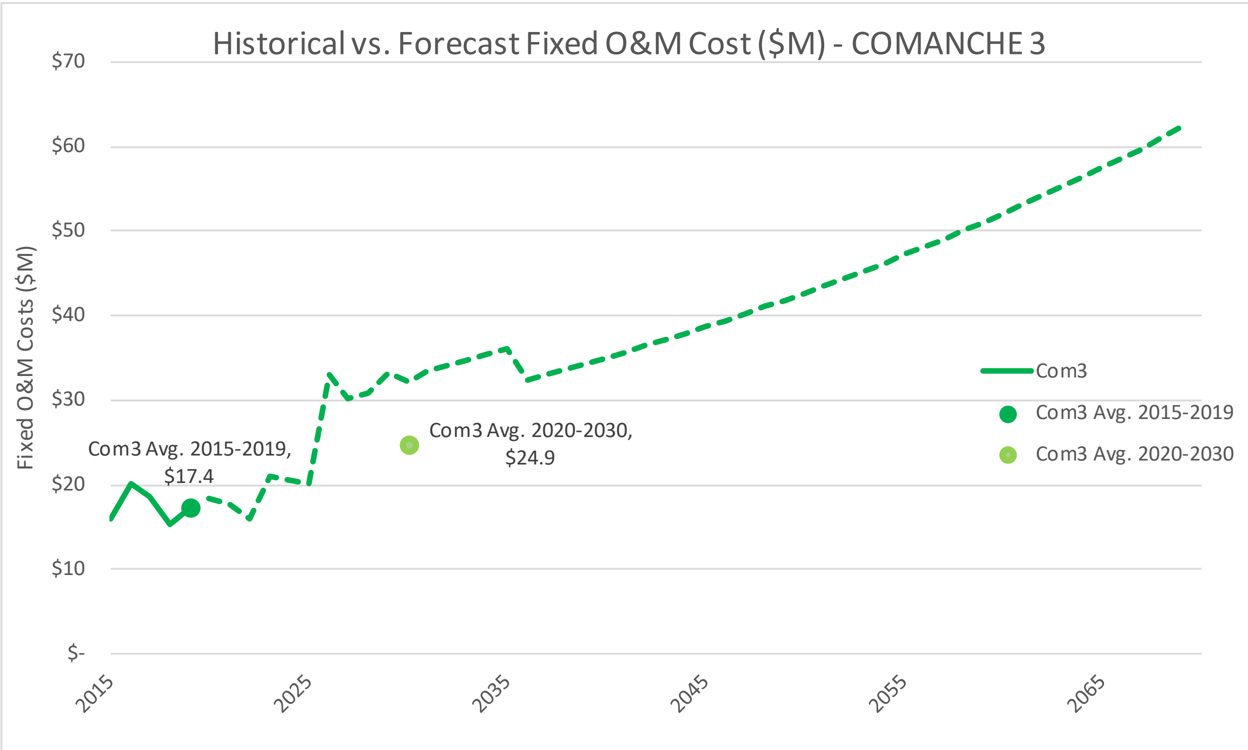


Figure 2.5-17 shows the historical (solid line) and forecasted (dashed line) fixed O&M costs for intermediate resources.

Figure 2.5-17 Intermediate Resources Historical and Forecasted Fixed O&M

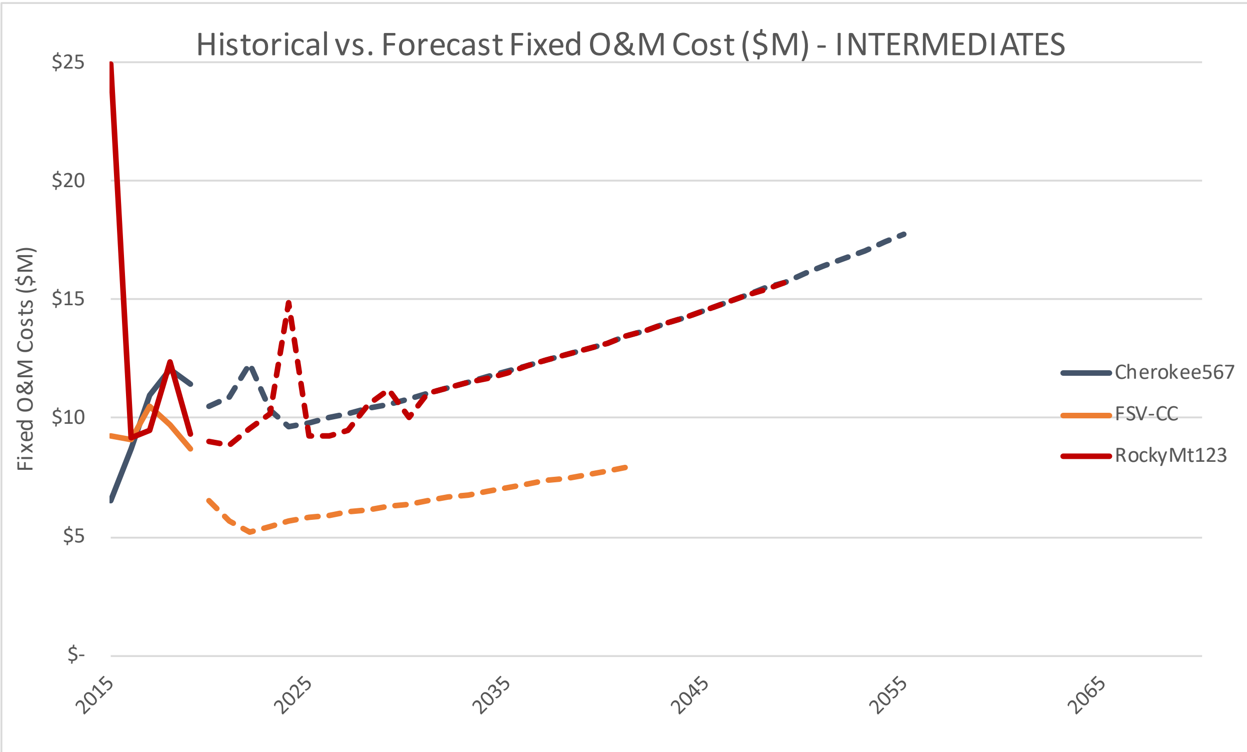


Figure 2.5-18 shows the historical (solid line) and forecasted (dashed line) fixed O&M costs for peaking and pumped storage resources.

Figure 2.5-18 Peaking and Pumped Storage Resources Historical and Forecasted Fixed O&M

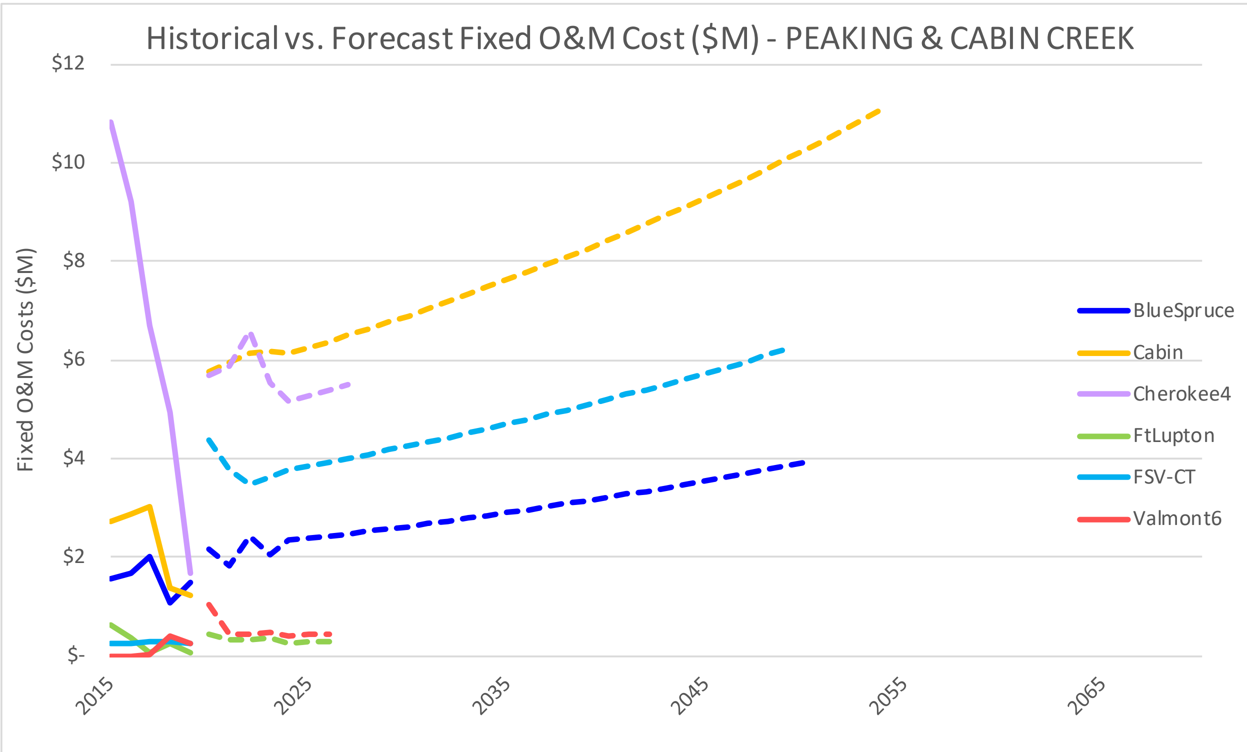


Figure 2.5-19 shows the historical (solid line) and forecasted (dashed line) variable O&M costs for baseload resources.

Figure 2.5-19 Baseload Resources Historical and Forecasted Variable O&M

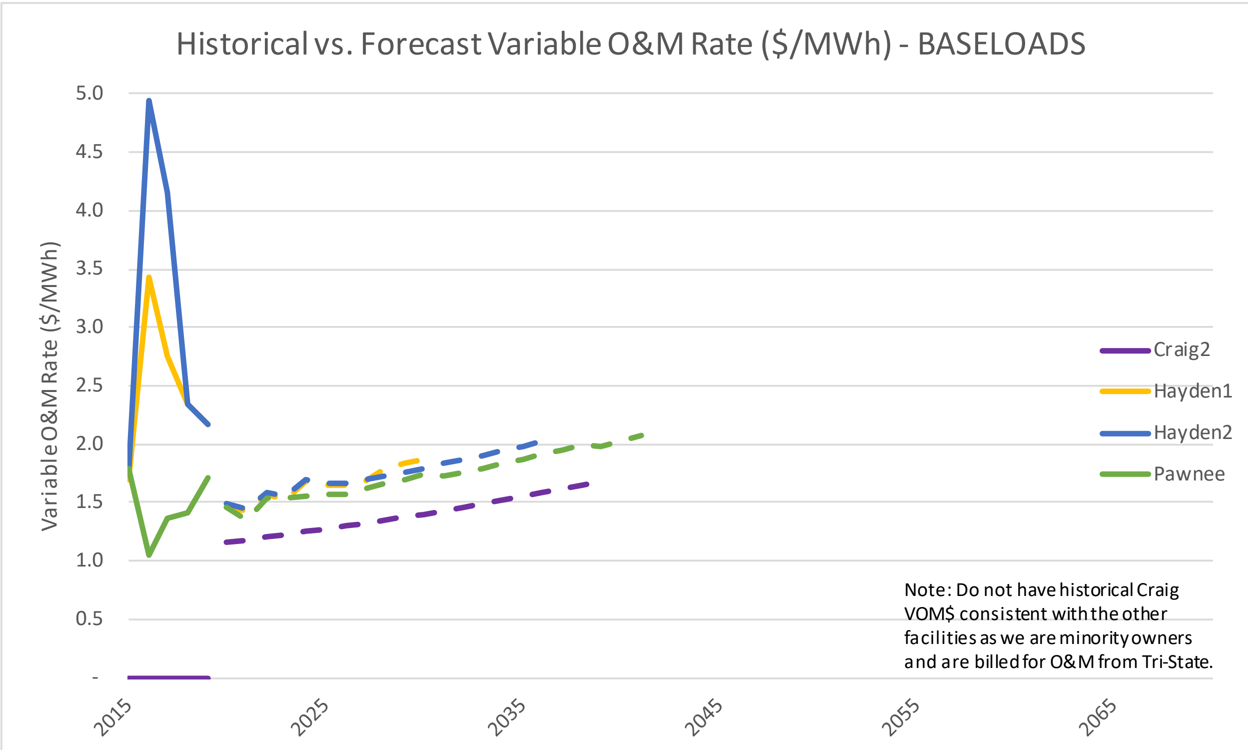


Figure 2.5-20 shows the historical (solid line) and forecasted (dashed line) variable O&M costs for Comanche 3.

Figure 2.5-20 Comanche 3 Historical and Forecasted Variable O&M

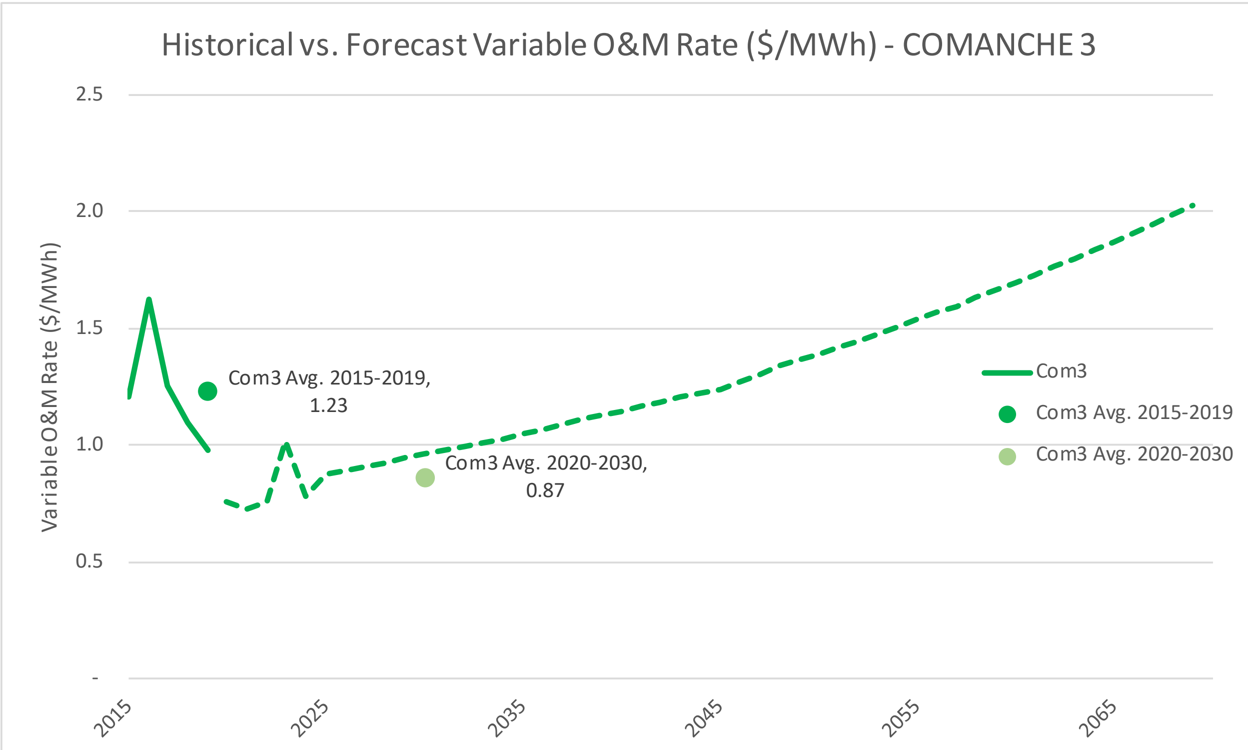
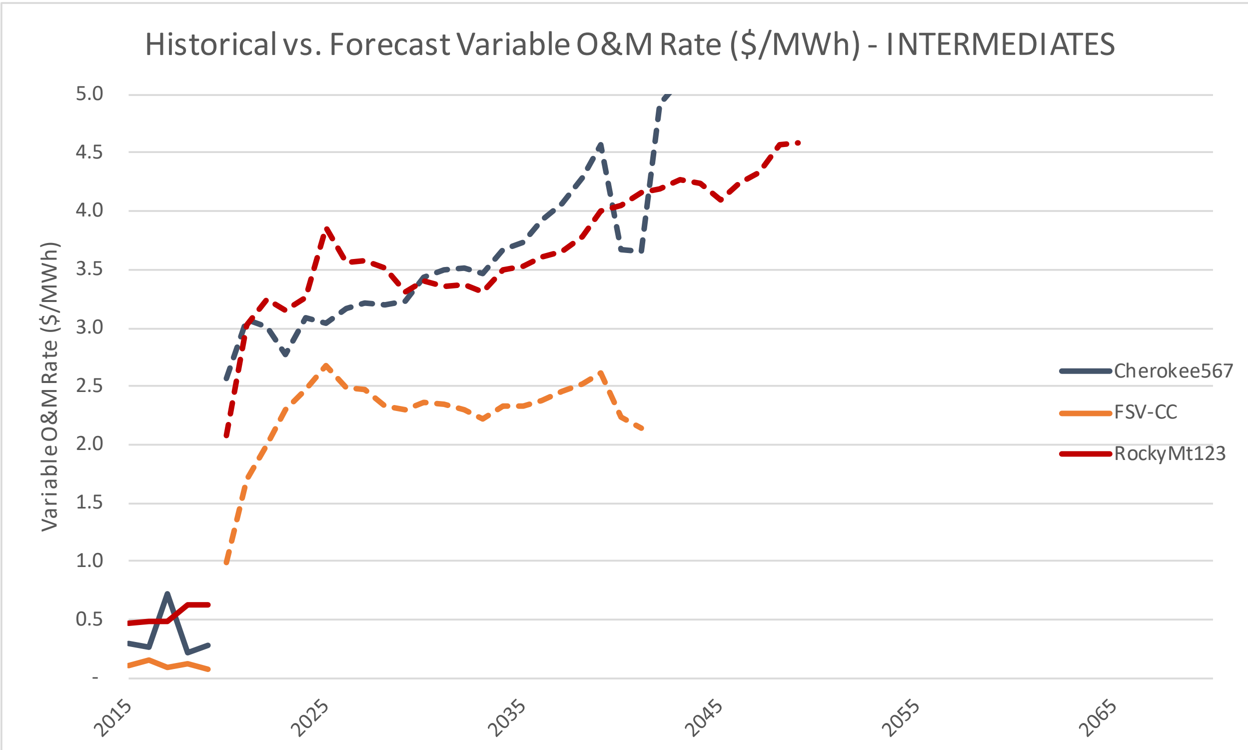


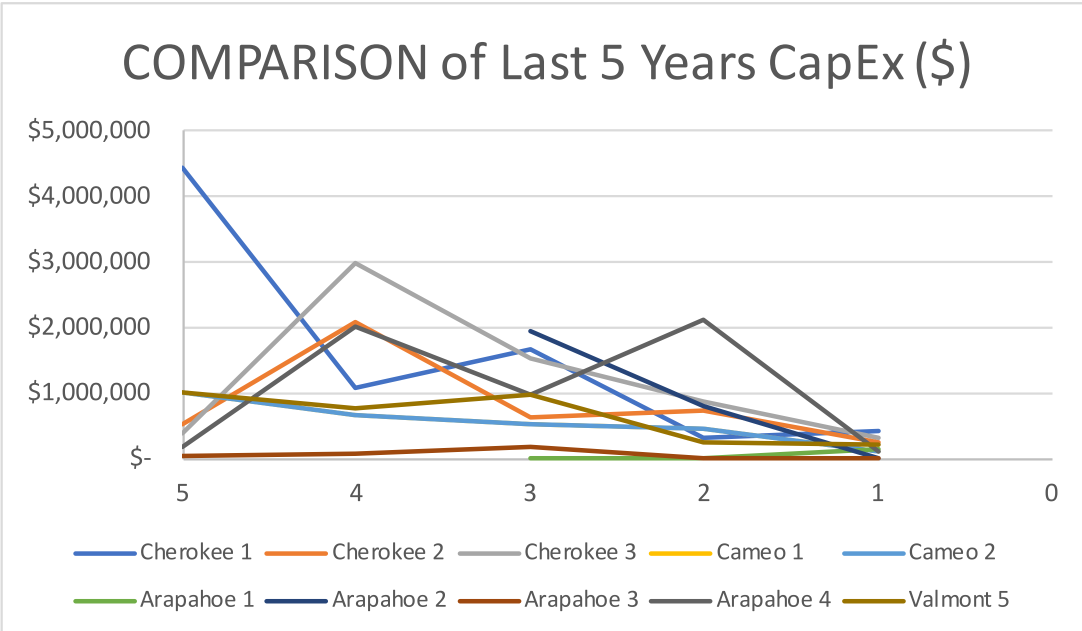
Figure 2.5-21 shows the historical (solid line) and forecasted (dashed line) variable O&M costs for intermediate resources.

Figure 2.5-21 Intermediate Resources Historical and Forecasted Variable O&M



Finally, Figure 2.5-22 shows the last five years of CapEx spends for various units before their retirements.

Figure 2.5-22 Retired Units Last 5 Years of CapEx



2.6 ASSESSMENT OF POTENTIAL EARLY RETIREMENTS

Background

In this Section, the Company presents an assessment of potential cost-effective early retirement of utility-owned resources with retirement dates during the planning period as contemplated by Proposed Draft Rule 3604(l) in Proceeding No. 19R-0006E. Although this Proposed Draft Rule will not be ultimately adopted by the Commission, the Company is voluntarily providing this supplemental information in response to the extensive stakeholder and Commission interest put forward over the course of Proceeding No. 19R-0096E.

Proposed Draft Rule 3604(l) states as follows:

> An assessment of potential cost-effective early retirements of utility-owned resources with retirement dates during the planning period, including the costs associated with incremental depreciation expenses and estimated operational and capital savings. For each early retirement reviewed, the utility shall describe the replacement resource need, possible system reliability impacts, and corrective actions for such impacts.

In its comments filed on May 7, 2020 in Proceeding No. 19R-0096E, the Company asserted that the benchmarking evaluation performed under Proposed Draft Rule 3607(c) (coupled with the statutory clean energy targets going out until 2050 that provide an ongoing carbon emissions reduction planning overlay on every ERP between now and 2050, and the application of the SCC to the development of resource plans) provides the Commission with the tools necessary to consider early unit retirements. Nonetheless, the Company used the EnCompass computer model to estimate the costs and benefits of retiring each Company-owned gas-fired resource with a retirement date prior to 2055 and provides this supplemental assessment below. Company-owned renewable resources were not included in this analysis. Company-owned coal units were not included as their evaluation is a core component of the CEP analysis.

Analysis Methodology

Costs and benefits associated with early retirement of each separate Company-owned resource were analyzed using the EnCompass computer model.

The analysis was performed as follows:

1. *Baseline Model*: The Company developed a baseline model representation of the Public Service electric power supply system for all years of the planning period (2021-2055). The model was run for years 2020-2050, and costs and load were repeated without inflation or growth for years 2051-2055. This baseline model included all existing Company-owned resources continuing to operate using their current fuel source, to their current retirement date. Each owned gas-fired

resource was modeled to include: the revenue requirements associated with recovery of undepreciated plant balance plus ongoing capital additions to the unit, to the current retirement date; fixed and variable O&M cost projections; and unit heat rate, fuel costs and emission rates. The baseline model was developed using SCC for CO_2 expansion plan selection and $0/ton for CO_2 8760-dispach, and the same system assumptions as those used in modeling the Company's ERP and CEP plans (e.g., load, fuel prices, generic resource alternatives, etc.). The model was run for the entire 2021-2055 planning period and the resulting planning period present value of revenue requirements ("PVRR") were calculated. The planning period PVRR from this baseline model was later compared with model runs in which each existing utility owned resource was early retired.

2. *Early Retirement Models*: The Company developed a series of early retirement models (7 total), each of which modifies the baseline model discussed above, by retiring a single Company-owned resource by EOY 2027. Each utility-owned resource being assessed in these early retirement models was represented with accelerated recovery of its undepreciated plant balance starting in year 2024 and ending EOY 2027. Fixed and variable O&M cost projections, unit heat rate, fuel costs, and emission rates for the retiring unit were modeled the same as in the baseline model up to EOY 2027, at which time the unit was retired in the modeling (i.e., shut off). Each early retirement model was run for years 2021-2055, during which the model could, at its discretion, backfill the capacity and energy of the retired utility resource from the suite of generic resources discussed in Section 2.14.

3. *Cost/Savings Calculation ($/kW)*: The planning period PVRR for each early retirement model was compared with that of the baseline model and a PVRR delta was calculated. A total of 7 PVRR deltas were developed (one for each of the 7 early retirement models). The cost or savings of early retiring each utility-owned resource was represented by dividing these resulting PVRR deltas by the kilowatt nameplate rating of the utility resource being assessed. In instances in which early retirement of a unit resulted in added cost to the system (i.e., a higher PVRR than the baseline PVRR), the resulting $/kW for that unit would be a positive number. In instances in which early retirement of a unit resulted in cost savings (i.e., a lower PVRR than the baseline PVRR), the resulting $/kW for that unit would be a negative number. Tables 2.6-1 and 2.6-2 summarize the results of the analysis.

Table 2.6-1 Potential Cost-Effective Early Retirement Analysis Results (PVRR Utility Cost)

			A	B	B - A	B - A
Plants with Retirement Dates within Planning Period	Gen Type	Nameplate Capacity (MW)	Baseline PVRR Utility Cost 2021-2055 ($M)	EOY 2027 Early Retire PVRR Utility Cost 2021-2055 ($M)	Delta ($M)	Delta ($/kW)
Cherokee 5,6,7	Gas CC	588	$38,545	$38,977	$432	$734
Ft. St. Vrain 1,2,3,4	Gas CC	798	$38,545	$39,027	$482	$604
Rocky Mt Energy Center	Gas CC	638	$38,545	$39,044	$499	$782
Blue Spruce 1 + 2	Gas CT	278	$38,545	$38,802	$257	$924
Ft. St. Vrain 5 + 6	Gas CT	303	$38,545	$38,753	$208	$685
Manchief 11 + 12	Gas CT	282	$38,545	$38,677	$131	$466
Valmont 7 + 8	Gas CT	84	$38,545	$38,636	$91	$1,079

Table 2.6-2 Potential Cost-Effective Early Retirement Analysis Results (PVRR Utility Cost + NPV CO_2)

			A	B	B - A	B - A
Plants with Retirement Dates within Planning Period	Gen Type	Nameplate Capacity (MW)	Baseline PVRR Utility Cost + NPV CO2 2021-2055 ($M)	EOY 2027 Early Retire PVRR Utility Cost + NPV CO2 2021-2055 ($M)	Delta ($M)	Delta ($/kW)
Cherokee 5,6,7	Gas CC	588	$47,318	$47,752	$434	$738
Ft. St. Vrain 1,2,3,4	Gas CC	798	$47,318	$47,820	$503	$630
Rocky Mt Energy Center	Gas CC	638	$47,318	$47,860	$542	$850
Blue Spruce 1 + 2	Gas CT	278	$47,318	$47,574	$256	$922
Ft. St. Vrain 5 + 6	Gas CT	303	$47,318	$47,549	$231	$763
Manchief 11 + 12	Gas CT	282	$47,318	$47,484	$166	$588
Valmont 7 + 8	Gas CT	84	$47,318	$47,418	$101	$1,199

Discussion

The results of this analysis summarized in Tables 2.6-1 and 2.6-2 show that early retirement of the existing gas-fired units evaluated results in added costs to customers in all cases. No coal units were included in this analysis as their cost effectiveness and potential early retirements are included in the CEP analysis.

This is not entirely unexpected, as the majority of these units have been in service for a number of years and the residual book value has diminished to the point where the capital carrying costs are relatively low and more economical than new construction thermal resources. Additionally, these units have very high ELCC values, requiring a disproportionate nameplate capacity of renewable or storage resources to replace their firm capacity contribution.

As shown in Table 2.6-2, the added costs to customers increase when including the SCC in the net present value calculations. This is because losing any gas-fired unit leads to an increase in coal generation, which has a higher CO_2 emissions rate per unit of energy than all gas-fired units.

2.7 ANCILLARY SERVICES ASSESSMENT

In this Section, the Company voluntarily presents an ancillary services assessment as contemplated by Proposed Draft Rule 3607(d) in Proceeding No. 19R-0096E. Although this Proposed Draft Rule will not be ultimately adopted by the Commission, the Company is providing this supplemental information in response to the extensive stakeholder and Commission interest put forward over the course of Proceeding No. 19R-0096E.

Proposed Draft Rule 3607(d) states as follows:

> Ancillary services assessment. The utility shall identify its existing resources that provide various ancillary services necessary to support its distribution and transmission systems, including, but not limited to, black start resources, non-spinning reserves, spinning reserves, regulation and frequency response, reactive power, voltage control, system control, dispatch services, and energy imbalance services.

In Decision No. C20-0207-I, the Commission explained that one purpose of the "ancillary services rule" proposed in the NOPR is to help the Commission gain greater familiarity with such services and how they are used by Colorado electric utilities.[5]

Table 2.7-1 provides this supplemental information identifying the Company's existing resources that provide various ancillary services.

[5] *See* Decision No. C20-0207-I, Proceeding No. 19R-0096E at ¶ 123.

Table 2.7-1 Ancillary Services Provided by Existing Resources

Generation Facility	Generation Type	Black Start	Non-Spinning Reserves	Spinning Reserves	Regulation and Frequency Response	Reactive Power	Voltage Control	System Control	Dispatch Services	Energy Imbalance Services
Comanche 1	Coal			x	x	x	x	AGC	x	x
Comanche 2	Coal			x	x	x	x	AGC	x	x
Comanche 3	Coal			x	x	x	x	AGC	x	x
Craig 1	Coal									
Craig 2	Coal									
Hayden 1	Coal			x	x			Manual	x	x
Hayden 2	Coal			x	x			Manual	x	x
Pawnee 1	Coal			x	x	x	x	AGC	x	x
PacifiCorp	Coal									
Cherokee 4	Gas Steam			x	x	x	x	AGC	x	x
Cherokee 5,6,7	Gas CC			x	x	x	x	AGC	x	x
Ft. St. Vrain 1,2,3,4	Gas CC			x	x	x	x	AGC	x	x
FSV Unit #4 - Upgrade	Gas CC			x	x	x	x	AGC	x	x
FSV Unit #3 - Upgrade	Gas CC			x	x	x	x	AGC	x	x
FSV Unit #2 - Upgrade	Gas CC			x	x	x	x	AGC	x	x
Rocky Mt Energy Center 1,2,3	Gas CC			x	x	x	x	AGC	x	x
RMEC #2 + 3 - Upgrade	Gas CC			x	x	x	x	AGC	x	x
RMEC #1 + 3 - Upgrade	Gas CC			x	x	x	x	AGC	x	x
Brush 4D	Gas CC			x	x	x	x	AGC	x	x
Arapahoe 5,6,7	Gas CC			x	x	x	x	AGC	x	x
Alamosa 1	Gas CT		x	x	x	x	x	Manual	x	x
Alamosa 2	Gas CT		x	x	x	x	x	Manual	x	x
Blue Spruce 1	Gas CT			x	x	x	x	AGC	x	x
Blue Spruce 2	Gas CT			x	x	x	x	AGC	x	x
Fruita 1	Gas CT		x	x	x	x	x	AGC	x	x
Ft. Lupton 1	Gas CT		x	x	x	x	x	AGC	x	x
Ft. Lupton 2	Gas CT		x	x	x	x	x	AGC	x	x
Ft. St. Vrain 5	Gas CT			x	x	x	x	AGC	x	x
Ft. St. Vrain 6	Gas CT			x	x	x	x	AGC	x	x
Valmont 6	Gas CT		x	x	x	x	x	AGC	x	x
Brush 1	Gas CC			x	x	x	x	AGC	x	x
Brush 2	Gas CC			x	x	x	x	AGC	x	x
Brush 3	Gas CT			x	x	x	x	AGC	x	x
Fountain Valley 1-6	Gas CT		x	x	x	x	x	AGC	x	x
Manchief - PPA	Gas CT			x	x	x	x	AGC	x	x
Plains End I	Gas CT	x	x	x	x	x	x	AGC	x	x
Plains End II	Gas CT	x	x	x	x	x	x	AGC	x	x
Spindle Hill 1 + 2	Gas CT			x	x	x	x	AGC	x	x
Cabin Creek A - MID REFURB	Storage									
Cabin Creek B - MID REFURB	Storage									
Cabin Creek A - 2022	Storage	x	x	x	x	x	x	AGC	x	x
Cabin Creek B - 2022	Storage	x						AGC		
Cabin Creek A	Storage	x	x	x	x	x	x	AGC	x	x
Cabin Creek B	Storage	x	x	x	x	x	x	AGC	x	x
Waste Management	Biomass									
Ames	Hydro									
Georgetown 1	Hydro									
Georgetown 2	Hydro									
Salida 2	Hydro									
Shoshone A	Hydro					x	x			
Shoshone B	Hydro					x	x			
Tacoma 1	Hydro									
Tacoma 2	Hydro									
City of Boulder - Betasso	Hydro									
City of Boulder - Silver Lake	Hydro									
City of Boulder - Lakewood	Hydro									
DWB - Foothills	Hydro									
DWB - Strontia	Hydro									
DWB - Dillon	Hydro									
DWB - Roberts Tunnel	Hydro									
DWB - Hillcrest	Hydro									
DWB - Gross Reservoir	Hydro									
Orchard Mesa/Grand Valley	Hydro									
Redlands Water & Power	Hydro									
Ute	Hydro									
STS (Mt. Elbert)	Hydro					x	x			

Generation Facility	Generation Type	Black Start	Non-Spinning Reserves	Spinning Reserves	Regulation and Frequency Response	Reactive Power	Voltage Control	System Control	Dispatch Services	Energy Imbalance Services
Pena Station	Solar									
SunE Alamosa I	Solar									x
Greater Sandhill	Solar									x
San Luis	Solar					x	x	AGC		x
Cogentrix Alamosa	Solar					x	x	AGC		x
Hooper	Solar				x	x	x	AGC	x	x
Comanche (Solar)	Solar				x	x	x	AGC	x	x
DG Solar*Rewards	Solar - BTM									
DG Solar*Rewards Community	Solar - Community									
DG Non-funded Solar	Solar - BTM									
DG Solar RETIREMENTS	Solar - BTM									
DG Solar Community RETIREMENTS	Solar - Community									
DG Solar FORECAST	Solar - BTM									
DG Solar Community FORECAST	Solar - Community									
Titan	Solar				x	x	x	AGC	x	x
Rush Creek I	Wind				x	x	x	AGC	x	x
Rush Creek II	Wind				x	x	x	AGC	x	x
NREL - DOE	Wind									
NREL - Gamesa	Wind									
NREL - Siemens	Wind									
Ridge Crest	Wind					x	x	Manual		x
Spring Canyon	Wind							Manual		x
Twin Buttes	Wind				x	x	x	Manual	x	x
Cedar Creek	Wind				x	x	x	AGC	x	x
Peetz Table	Wind				x	x	x	AGC	x	x
Logan	Wind				x	x	x	AGC	x	x
Northern Colorado I	Wind				x	x	x	AGC	x	x
Northern Colorado II	Wind				x	x	x	AGC	x	x
Cedar Creek II	Wind				x	x	x	AGC	x	x
Cedar Point	Wind				x	x	x	AGC	x	x
Limon I	Wind				x	x	x	AGC	x	x
Limon II	Wind				x	x	x	AGC	x	x
Limon III	Wind				x	x	x	AGC	x	x
Golden West	Wind				x	x	x	AGC	x	x
Bighorn	Solar							TBD		
Colorado Green	Wind				x	x	x	AGC	x	x
Mountain Breeze	Wind				x	x	x	AGC	x	x
Cheyenne Ridge	Wind				x	x	x	AGC	x	x
Bronco Plains	Wind				x	x	x	AGC	x	x
Valmont 7	Gas CT		x	x	x	x	x	AGC	x	x
Valmont 8	Gas CT		x	x	x	x	x	AGC	x	x
Hartsel	Solar							TBD		
Sun Mountain	Solar							TBD		
Front Range-Midway - Solar	Solar							TBD		
Front Range-Midway - Storage	Storage							TBD		
Neptune - Solar	Solar							TBD		
Neptune - Storage	Storage							TBD		
Thunder Wolf - Solar	Solar							TBD		
Thunder Wolf - Storage	Storage							TBD		
Mkt Purchase - Basin Electric Coop I	Market Purchase							Sched		
Mkt Purchase - PRPA	Market Purchase							Sched		
Mkt Purchase - Basin Electric Coop II	Market Purchase							Sched		
Firm Transmission Import	Firm Trans Import							Sched		

2.8 TRANSMISSION RESOURCES

In this Section, the Company provides Transmission Resources information required by Rule 3608 as described below. This Section begins with an overview of the electric transmission system and existing transmission capabilities, and a discussion of transfer capability limitations on the transmission network. Next, this Section discusses transmission projects implemented since the 2016 ERP and other transmission facilities and upgrades planned through 2030, including Colorado's Power Pathway 345 kV Transmission Project. Last, this Section discusses transmission service and coordination agreements.

Electric Transmission System Overview

As of 2020, Public Service owns and maintains approximately 4,867 circuit-miles of transmission lines, all of which are located inside Colorado. The transmission lines are rated 44 kV, 69 kV, 115 kV, 138 kV, 230 kV, and 345 kV. The Company also uses 236 transmission and distribution substations to transform and deliver electric energy.

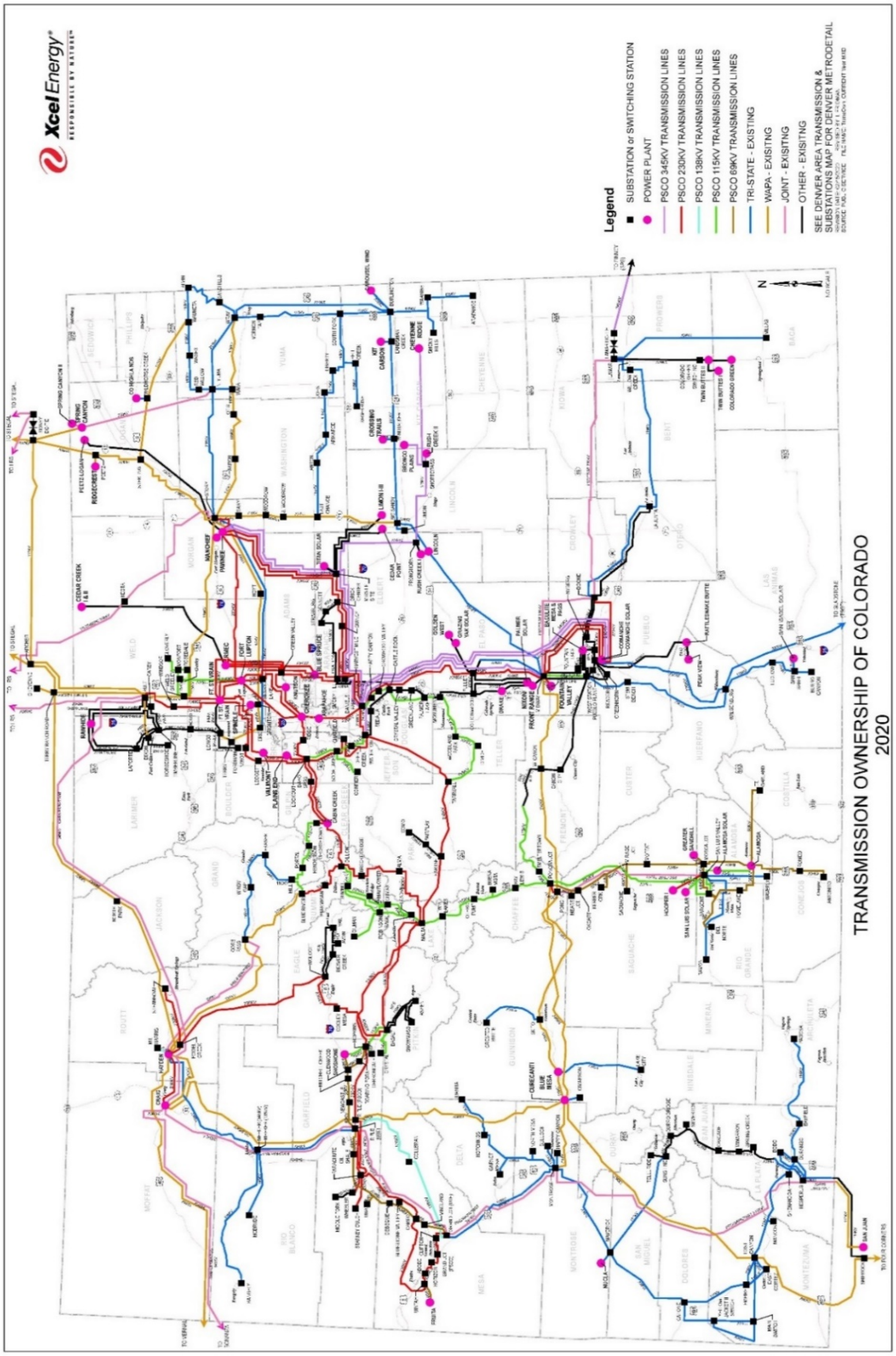
Colorado is on the eastern edge of the Western Electric Interconnection, which operates asynchronously from the Eastern Electric Interconnection. The Public Service–Southwestern Public Service Company Tie-line and 210 MW High Voltage Direct Current ("HVDC") back-to-back converter station, in-service since December 31, 2004, provides the first link in Colorado between the two interconnections.

Public Service has ownership in the jointly owned western slope transmission facilities extending from the Craig/Hayden area in Northwestern Colorado south to the Four Corners area.

The bulk power transmission system within the Denver/Boulder metro area consists primarily of a double-circuit 230 kV loop around the Denver metro region. This outer belt loop feeds into the 230 kV and 115 kV load-serving networks at various points on the system. 345 kV transmission helps serve the Denver metro loads with wind and solar generation resources located in the Pawnee, Limon, and Pueblo areas.

Figure 2.8-1 shows a map of the 2020 Colorado Transmission System including Public Service's transmission facilities.

Figure 2.8-1 Colorado Transmission Map



TOT Transfer Capability Limitations

In this Section, the Company provides information regarding the location and extent of transfer capability limitations on its transmission network as required by Rule 3608(a).

Public Service shares ownership in four jointly owned transmission corridors within the Colorado/Wyoming/Utah/New Mexico area. These jointly owned transmission corridors are called “TOTs,” which is an acronym for “total of transmission.” These TOTs are numbered 2A, 3, 5, and 7. The Total Transfer Capability (“TTC”) across these TOTs is developed regularly by coordination and agreement of the owners of the TOT facilities.

The North American Electric Reliability Corporation (“NERC”) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards, annually assesses seasonal and long-term reliability, monitors the bulk power system through system awareness, and educates, trains, and certifies industry personnel. The Southwest Power Pool (“SPP”) also provides situational awareness and real-time monitoring of the TOTs in its role as the Reliability Coordinator (“RC”) for Public Service.

The Rocky Mountain Operating Study Group (“RMOSG”), of which Public Service is a participating member, reviews and approves the TTCs for each of the four TOTs (2A, 3, 5 and 7). The RMOSG is one of four Regional Study Groups in the Western Electricity Coordinating Council (“WECC”) that annually performs studies to determine the seasonal TTCs. Each Regional Study Group is responsible for reviewing and approving the seasonal TTCs and submitting the results to SPP.

Presently, Public Service’s TTC allocations on these TOTs are committed to serve Public Service native load. Public Service posts available transmission capability (“ATC”) on the WestTrans OASIS node at http://www.oatioasis.com. Transmission tariffs, including transmission terms, conditions, and pricing, are posted on the WestTrans OASIS node.

Figure 2.8-2 illustrates the TOT locations. The power transferred across these TOT paths is continuously monitored by the designated operating agent for each TOT to ensure that the path limits (TTCs) are not exceeded. All TOTs have been rated by WECC and the Transmission Providers that jointly own the TOTs. Public Service shows TOT 1A in Figure 2.8-2 but does not further describe the TOT in this report as Public Service does not have any transmission rights on TOT 1A.

Figure 2.8-2 Colorado TOT Transmission Path Map

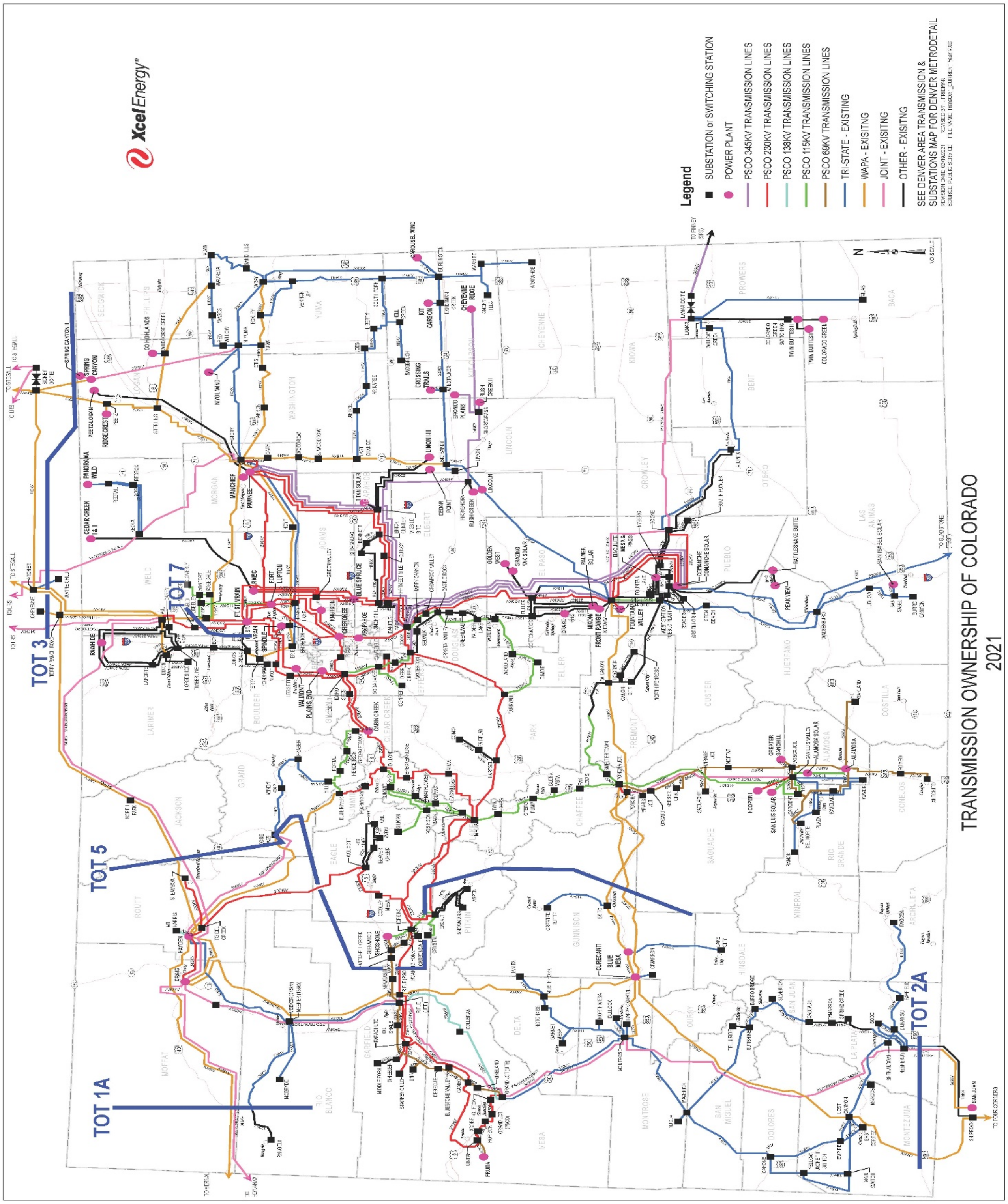


Table 2.8-1 shows Public Service's TOT capability on each path.

Table 2.8-1 TOT Transmission Transfer Capability Limitations (2021)

Path	Transmission Lines	Public Service Firm Path Transfer Capability (MW)		Public Service Capability Committed (MW)
TOT 2A	Waterflow-San Juan 345 kV Hesperus-Glade Tap 115 kV Lost Canyon-Shiprock 230 kV	135 north-south	200 south-north	135 north-south 200 south-north
TOT 3	Archer-Ault 230 kV LRS-Ault 345 kV LRS-Story 345 kV Cheyenne-Owl Creek 115 kV Sidney-Sterling 115 kV Sidney-Spring Canyon 230 kV Cheyenne-Ault 230 kV	56 north-south	56 south-north	56 north-south 0 south-north
TOT 5	North Park-Archer 230 kV Craig-Ault 345 kV Hayden-Gore Pass 230 kV Hayden-Gore Pass 138 kV Gunnison – Poncha 115 kV Curecanti-Poncha 230 kV Hopkins-Malta 230 kV Basalt-Malta 230 kV	480 west-east	480 east-west	480 west-east 480 east-west
TOT 7	Weld-Fort St. Vrain 230 kV Longs Peak -FSV 230 kV Ault-Fort St. Vrain 230 kV	516 north-south	516 south-north	516 north-south 2 south-north

TOT 2A

TOT 2A represents the transmission path that connects southwestern Colorado with New Mexico and Arizona. This path is comprised of three transmission lines and has a north to south limit of 690 MW minus net load in the Montrose-Curecanti-San Juan-Shiprock area of southwest Colorado. The limit is based on a single contingency of the Hesperus-San Juan 345 kV line. The path is jointly owned by WAPA, Tri-State, and Public Service. The south to north limit is not defined, but Public Service has ownership rights to 200 MW of transfer capability in the south to north direction on this path and a 135 MW share of the maximum north to south transfer capability of 690 MW. However, the limit is dynamic and monitored continuously. The limit is also highly dependent on local southwest Colorado loads and drops significantly as the loads increase and when southwest Colorado generation is off-line.

TOT 3

TOT 3 is the transmission path that connects Wyoming and Nebraska with northeastern Colorado. This path is comprised of seven transmission lines and presently has a maximum north to south transfer limit of 1,680 MW that is adjusted seasonally to account for load and local generation variations.

WAPA, Tri-State, Basin Electric Power Cooperative, Wyoming Municipal Power Agency, Municipal Energy Agency of Nebraska, Los Alamos County and Public Service jointly own the TOT 3 transmission lines. Public Service owns 3.57& of the path which equites to 60 MW of firm transfer capability on TOT 3 in the north to south direction. Since the south to north limit is not defined at this time, Public Service-owned transfer capability is the same 60 MW south to north.

Operationally, TOT 3 is the most constraining transmission path used to import power into eastern Colorado. Once the TOT 3 capacity limit is reached, further schedules into eastern Colorado over TOT 5 result in the overloading of TOT 3. In this condition the overloading of TOT 3 is due to the increased (west to east) flow on TOT 5's North Park-Terry Ranch Road 230 kV line into Wyoming, resulting in an increased (north to south) flow on TOT 3's Terry Ranch Road-Ault 230 kV line into Colorado.

TOT 5

TOT 5 represents the transmission path that connects western Colorado to eastern Colorado. The TOT 5 path is comprised of eight transmission elements and presently has a west to east operating transfer limit of 1,680 MW. The west to east rating of the path is defined through established operating practices. WAPA, Tri-State, Platte River Power Authority ("PRPA"), and Public Service jointly own the TOT 5 transmission lines. Public Service owns 480 MW of firm transfer capability on TOT 5 in the west to east direction and, since the east to west limit is not defined at this time, Public Service-owned transfer capability is the same 480 MW east to west.

Public Service's 480 MW firm transfer capability in the west to east direction on TOT 5 is fully committed to transmitting capacity and associated energy from the Company's purchased power resources and from Company-owned resources located in western Colorado. Public Service has committed the east to west direction as backup for western Colorado loads and for counter-scheduling needs.

TOT 7

TOT 7 is south of the TOT 3 path and consists of three transmission lines that transfer power to the north Denver metro area. The TOT 7 path has a north to south transfer limit of 890 MW. The south to north transfer limit is not defined at this time.

Public Service and PRPA jointly own TOT 7. Public Service owns 516 MW of firm transfer capability on TOT 7. Since TOT 7 is located east of TOT 5 and south of TOT 3, TOT 7 use generally requires coordinated use of both the TOT 3 and TOT 5 paths.

Senate Bill 07-100 New Transmission Additions

Rule 3608(b) requires the Company to provide a description of all transmission lines and facilities appearing in its most recent report filed with the Commission pursuant to § 40-2-126, C.R.S. that, as identified in that report, could reasonably be placed into service during the RAP.

Senate Bill 07-100 ("SB 07-100"), which is codified at § 40-2-126, C.R.S., was signed into law in 2007 to expand Colorado's electric transmission system and promote the use of renewable resources. It established requirements for utilities to continually evaluate and, if necessary, improve electric transmission facilities to meet the state's existing and future energy needs. Five Energy Resource Zones ("ERZs") with significant renewable energy potential were also identified. Historically, Public Service filed SB 07-100 Reports by October 31 of each odd-numbered year. In 2017, Decision No. R17-0747 in Proceeding 17R-0489E subsequently modified the Commission's Rules implementing SB 07-100 to allow the Company to demonstrate compliance with the requirements of SB 07-100 as part of the biennial 10-Year Transmission Plan filed pursuant to Rule 3627 ("Rule 3627 Report"), combining the two filings into a single proceeding. The SB 07-100 Report is now located within the Rule 3627 Report. The Company filed its most recent Rule 3627 Report in February 2020 (Proceeding No. 20M-0008E). The February 2020 Rule 3627 Report is available on Xcel Energy's Transmission website.[6]

Energy Resource Zones

Public Service first designated ERZs in its 2007 SB 07-100 Report, and through its subsequent 2008 Informational Report and 2009 SB 07-100 Report revised those designated ERZs to the number and status described below:

> ERZ 1: In Northeast Colorado, ERZ 1 includes all or parts of Sedgwick, Phillips, Yuma, Washington, Logan, Morgan, Weld, and Larimer Counties. The geography of this ERZ is similar to the way it was described in the 2007 SB 07-100 Report, but it has been redrawn to provide clarity so that major metropolitan areas (particularly the greater Denver metro area) are not included in any ERZ.
>
> ERZ 2: ERZ 2 is in East Central Colorado, and includes all or parts of Yuma, Washington, Adams, Arapahoe, Elbert, El Paso, Lincoln, Kit

[6] http://www.transmission.xcelenergy.com/Planning/Planning-for-Public-Service-Company-of-Colorado.

Carson, Kiowa, and Cheyenne Counties. The geography of this ERZ is also similar to that described in the 2007 SB 07-100 Report but has been redrawn to remove the greater Denver metro area as well as parts of Colorado Springs.

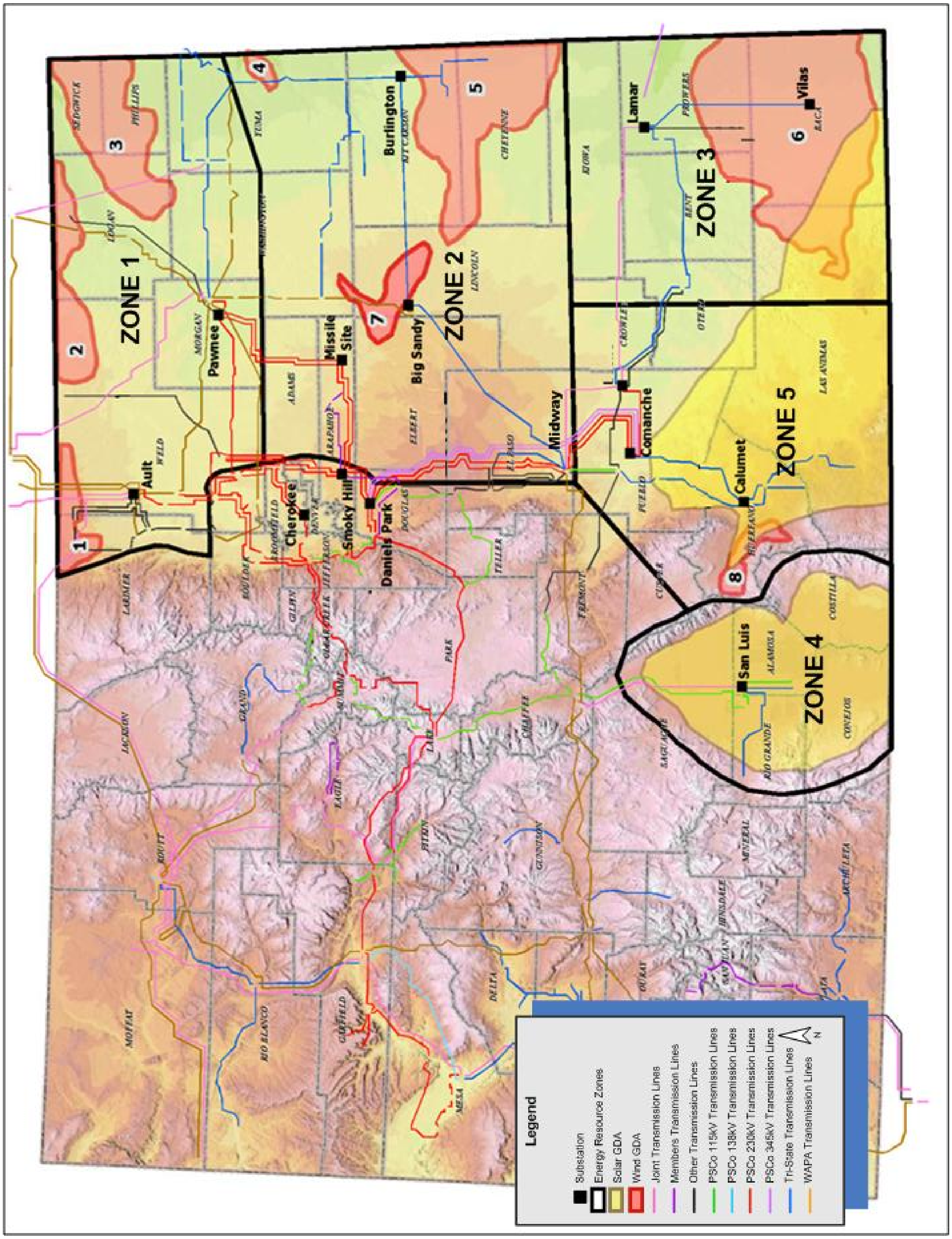
ERZ 3: ERZ 3 is in Southeast Colorado, and includes all or parts of Baca, Prowers, Kiowa, Crowley, Otero, Bent, and Las Animas Counties. This ERZ is somewhat smaller than the ERZ 3 that was described in the 2007 SB 07-100 Report; its western portion is now in ERZ 5.

ERZ 4: ERZ 4 is in the San Luis Valley, and includes all or parts of Costilla, Conejos, Rio Grande, Alamosa, and Saguache Counties. This ERZ is somewhat smaller than the ERZ 4 created for the 2007 SB 07-100 Report, as it now includes only the San Luis Valley region and does not include any of wind Generation Development Area ("GDA") 8 which is now located wholly within the new ERZ 5.

ERZ 5: ERZ 5 is in South-Central Colorado, and includes all or parts of Huerfano, Pueblo, Otero, Crowley, Custer, and Las Animas Counties.

Figure 2.8-3 illustrates the five ERZs overlaid upon the wind and solar GDAs that were identified in the 2007 Senate Bill 07-091 Task Force Report.

Figure 2.8-3 Energy Resource Zones with Generation Development Areas



Pursuant to Rule 3608(b) and 3608(c), Table 2.8-2 below provides a description of all transmission lines and facilities appearing in the Company's most recent report filed with the Commission pursuant to § 40-2-126, C.R.S. (i.e., the February 2020 Rule 3627 Report), that, as identified in that report, could reasonably be placed into service during the RAP.

The SB 07-100 project that is likely to be placed in service during the RAP is Colorado's Power Pathway 345 kV Transmission Project, which is described in detail below.

Table 2.8-2 SB 07-100 Projects Likely to be In-Service During the RAP

Project	ERZs	CPCN Status	Currently Scheduled In-Service Date	Estimated Cost ($ millions)	Injection Capability	Approximate Length (Miles)
Colorado's Power Pathway Transmission Project	1, 2, 3, 5	Filed on March 2, 2021	2025 – 2027	1,750	3000 – 3500	560

Implemented SB 07-100 Transmission Projects Since the 2016 ERP

1. **Pawnee – Daniels Park 345 kV Transmission Project (ERZ 1)**
   Description: This project was filed in the 2007 SB 07-100 Report and consists of developing approximately 95 miles of 345 kV transmission between the Pawnee Substation near Brush, Colorado, and the Daniels Park Substation, south of Denver along with approximately 25 miles of 345 kV transmission between the Daniels Park Substation and the Harvest Mile Substation, east of Denver. The project allows for approximately 800 MW of additional resources in ERZs 1 and 2, interconnected at or near the Pawnee and Missile-Site Substations. The Missile Site 345 kV substation (ERZ 2) bisects the project.

   Status: The project was placed in service in December 2019.

Colorado's Power Pathway 345 kV Transmission Project

On March 2, 2021, Public Service filed an Application for a CPCN in Proceeding No. 21A-0096E for the Colorado's Power Pathway 345 kV Transmission Project (the "Pathway Project"). The Pathway Project is a 560-mile, 345 kilovolt ("kV") double circuit transmission facility that will provide a high voltage networked transmission facility that interconnects the Eastern Plains and Southern Colorado to Public Service's load centers, providing developers the ability to develop and bid cost-effective projects into renewable-rich ERZs 1, 2, 3, and 5.

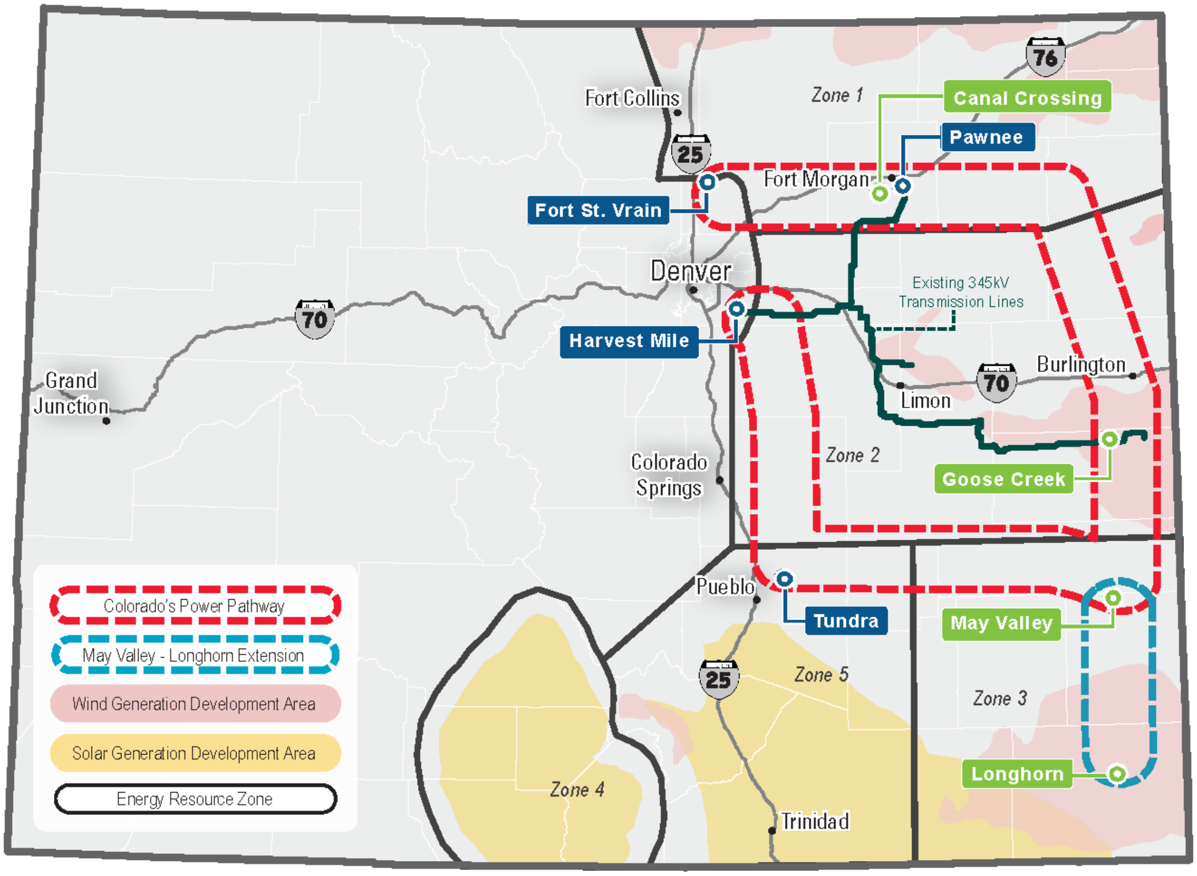
As detailed in Proceeding No. 21A-0096E, the Pathway Project is comprised of five project segments. The northern terminus of the Pathway Project will be at the Company's existing Fort St. Vrain Substation (located at the Fort St. Vrain generating station) in Platteville in western Weld County. The Pathway Project will then span east to a new substation near Pawnee, east/southeast to near the Cheyenne Ridge Wind Project, south to near Lamar, and then west to the Tundra Substation, near the Comanche generating plant. The Pathway Project will then run north to the Company's existing Harvest Mile Substation, located adjacent to the City of Aurora in Arapahoe County.

In its CPCN Application, Public Service also presented for Commission consideration a 90-mile, 345 kV extension called the May Valley-Longhorn Extension. The May Valley-Longhorn Extension would involve constructing approximately 90 miles of new 345 kV double circuit transmission line from the new May Valley Substation, at the southeastern corner of the Pathway Project near Lamar,[7] south to a new Longhorn Substation located near Vilas, Colorado. This optional extension to the Pathway Project would establish additional transmission interconnection opportunities for potential clean energy resource developers in the wind-rich southeastern area of the state. The Company anticipates that having a well-planned transmission line to this area will not only facilitate clean energy resource development, but also minimize the potential likelihood of clean energy project developers needing to construct multiple generation tie lines in this region to interconnect to the Pathway Project, at potentially high costs to individual generation projects bid into this and future ERPs.

A vicinity map of the five segments comprising the Pathway Project and the May Valley-Longhorn Extension relative to the ERZs is shown in Figure 2.8-4 below. As discussed in the Company's CPCN filing in Proceeding No. 21A-0096E, a transmission line route has not been identified. Therefore, the vicinity map below shows the general study area within which the transmission line will be routed as the project develops.

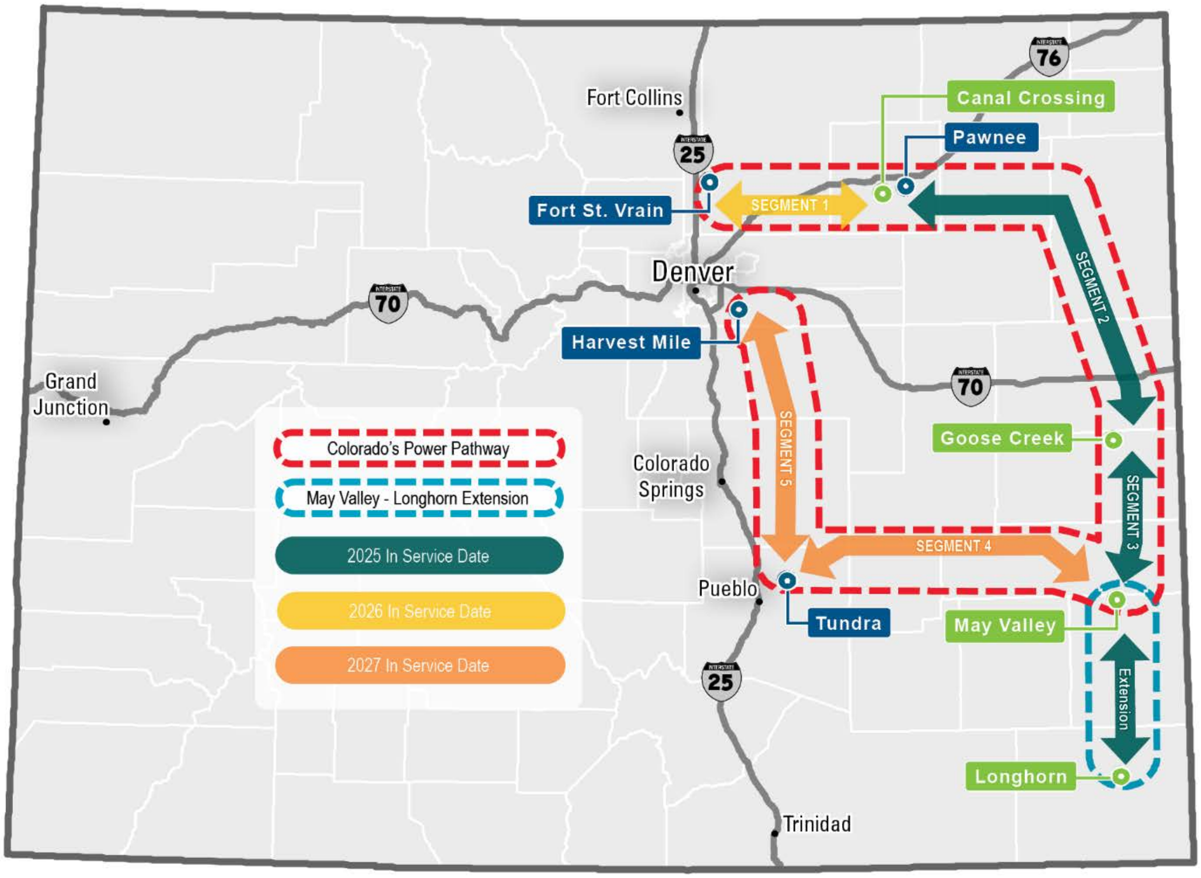
[7] Note the May Valley Substation will be constructed as part of the Pathway Project even if the May Valley-Longhorn Extension is not approved.

Figure 2.8-4 Pathway Project and May Valley-Longhorn Extension Vicinity Map



The Pathway Project will be constructed in three phases with certain segments planned to be in-service by the end of 2025, and subsequent segments planned to be in-service by 2026 and 2027 as shown in Figure 2.8-5 below. Segments 2 and 3 will traverse the wind-rich areas in eastern Colorado. By having those segments and substations constructed and in-service by the end of 2025, wind and solar developers will be able to interconnect their resources prior to the expiration of the Production Tax Credits ("PTCs") and Investment Tax Credits ("ITCs"). Bids submitted by generation developers will enable significant cost savings to customers if those generating resources can be online before the end of 2025, which is when the PTC is set to expire and the ITC steps down. Thus, Public Service anticipates that placing Segments 2 and 3 and the May Valley-Longhorn Extension (if approved) in service by the end of 2025 could drive clean energy cost savings for customers. A map of the Pathway Project segments and estimated in service dates is shown in Figure 2.8-5.

Figure 2.8-5 Pathway Project and May Valley-Longhorn Extension Estimated In-Service



The Pathway Project will effectuate an interconnected transmission system that: (1) achieves improved reliability and operational flexibility while interconnecting needed clean generation resources; and (2) enables the delivery of electric energy from these generation resources to the Company's load centers. An additional benefit of the Pathway Project is that it will network a large portion of the existing, Rush Creek and Cheyenne Ridge 345 kV transmission line(s) that together effectively comprise a 153-mile radial generator tie-line currently connected to Public Service's networked transmission system only at Missile Site Substation.

Joint Transmission Proposal

October 30, 2020, the Company filed Updated Joint Transmission Proposal and Joint Final Comments (the "Joint Transmission Proposal") in response to Decision No. C20-0661-I in the ERP rulemaking proceeding (Proceeding No. 19R-0096E). The Joint

Transmission Proposal was a consensus proposal put forward by a diverse coalition of stakeholders that aimed to better align transmission planning and resource planning by allowing bidding into bid-eligible planned transmission projects in the Phase II competitive solicitation without burdening developers with costs from the transmission project.[8] The Joint Transmission Proposal also sets forth a process whereby the Commission approves a "menu" of bid-eligible planned transmission projects as part of the Phase I decision.[9] The Joint Transmission Proposal did not preclude the filing of CPCNs for new transmission ahead of an ERP, as the Company has done with the Pathway Project (filed in Proceeding No. 19A-0096E).

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.[10] However, one of the items the Commission focused on in those deliberations was the Joint Transmission Proposal. During their deliberations, the Commission lauded the work which yielded the Joint Transmission Proposal and encouraged the use of the process, outside of new Rules, if applicable. The Commission directed the Company to address in its 2021 ERP & CEP, to the extent necessary, how the Company has incorporated the Joint Transmission Proposal into its 2021 ERP & CEP, but recognized that since the development of the Joint Transmission Proposal the Company has filed a CPCN for the Pathway Project.

While the Pathway Project is conceptually consistent with the Joint Transmission Proposal's objective of providing bidders with greater certainty around transmission assets, it does not meet the definition *per se* of a bid-eligible transmission resource under the Joint Transmission Proposal. Notably, the Joint Transmission Proposal contemplates the designation of planned transmission as bid-eligible in the Phase I process, with the Phase II process ultimately determining if the Company should move forward with CPCNs for the designated planned transmission projects. An ERP Phase II decision is not expected until late 2022 or early 2023, which will not allow time to develop the Pathway Project and have certain segments in service by 2025. Given these timing issues, the Company filed its CPCN for the Pathway Project ahead of this ERP.

The Company is not proposing any bid-eligible planned transmission under the Joint Transmission Proposal. The Company has considered other transmission projects such as the Weld County Expansion Project and San Luis Valley Project, but ultimately

[8] Proceeding No. 19R-0096E, Updated Joint Transmission Proposal and Joint Final Comments to Decision No. C20-0661-I (filed Oct. 30, 2020), at 9-10.

[9] Proceeding No. 19R-0096E, Updated Joint Transmission Proposal and Joint Final Comments to Decision No. C20-0661-I (filed Oct. 30, 2020), at 9-10.

[10] As of the writing of this testimony, the Commission's written Decision is pending.

determined that these projects were not sufficiently developed to designate them as bid-eligible at this time.

While the Pathway Project is not “designated” as a planned transmission project such that it would go through the process contemplated under the Joint Transmission Proposal, the Pathway Project has been studied by the Colorado Coordinated Planning Group (“CCPG”) and has its roots in the Lamar-Front Range project that has been a long considered transmission solution in Colorado. Accordingly, the Company views the Pathway Project as being consistent with the spirit of the Joint Transmission Proposal and goes towards the same ends—identifying strategic transmission investment that can unlock cost-effective clean energy *ahead* of the Phase II competitive solicitation as opposed to waiting to see where the generation resources in the final portfolio are located.

Other Transmission Facility Additions Pursuant to § 40-2-126, C.R.S. (2020 Rule 3627 Report)

The Company has plans for new transmission facilities and system upgrades as outlined below.

Transmission Facilities/Upgrades completed in 2020 and scheduled for completion in 2021:

1) Pawnee – Daniels Park 345 kV Line
2) Harvest Mile – Daniels Park 345 kV Line
3) Colorado Energy Plan Portfolio (CEPP) Interconnection Facilities
    a. Shortgrass 345 kV Switching Station
    b. Shortgrass – Cheyenne Ridge 345 kV Gen-Tie Line
4) Colorado Energy Plan Portfolio (CEPP) Voltage Control Facilities
    a. Missile Site 345 kV, 3×120 Mvar Capacitor Banks
    b. Harvest Mile 345 kV, 2×240 Mvar Capacitor Banks
    c. Daniels Park 345 kV, 1×120 Mvar Capacitor Bank
    d. Pronghorn 345 kV, ±150 Mvar StatCom
    e. Shortgrass 34 5kV, 2×30 Mvar Shunt Reactors
5) Sullivan 230 kV Reconfiguration for 230/13.8kV Distribution Transformer #3
6) Thornton 115 kV Distribution Substation
7) NREL 115 kV Station

Transmission Facilities/Upgrades planned through 2030:[11]

1) Colorado Energy Plan Portfolio (CEPP) Interconnection Facilities
   a. Mirasol 230 kV Switching Station
   b. Tundra 345 kV Switching Station
   c. Hartsel-Tarryall 230 kV Switching Station
2) Greenwood – Denver Terminal 230 kV Line
3) Flying Horse – Monument 115 kV Series Reactor (CSU Flow Mitigation)
4) Bluestone Valley 230 kV Substation
5) Avon – Gilman 115 kV Line
6) Climax – Robinson Rack – Gilman 115 kV Line
7) Ault – Husky 230 kV line
8) Husky – Graham Creek – Cloverly 115 kV line
9) Husky 230/115 kV Substation
10) Graham Creek 115 kV Station

Please see Proceeding No. 20M-0005E (2020 Rule 3206 Report) and Proceeding No. 20M-0008E (2020 Rule 3627 Report) for additional details.

Transmission Injection Capability

Injection[12] capability at any system location is inherently a moving target that varies with the prevailing system conditions characterized by system load level and economic generation dispatch. This is primarily driven by: (1) the coincident[13] production of wind and solar at system peak times, and (2) the hourly output capacity and interconnection locations of each interconnected generation resource.

The injection capability determined for a given location in the transmission system is highly dependent on the assumed generation and storage dispatch pattern. Therefore, the maximum injection capability corresponds only to the most favorable system condition expected to occur, which is not a valid metric for the actual injection capability, as this rarely occurs. In the past, due to a very limited set of typical generation and storage dispatch patterns associated with the economic dispatch of conventional resources (e.g., coal, gas, and hydro) and use of storage resources such as Cabin Creek, transmission injection capability would typically fall within a narrower range and could be determined with a high level of certainty. However, with increasing levels of variable resources integrated into the PSCo Balancing Authority Area ("BAA"), the

[11] Excluding the Pathway Project.

[12] The "injection" or output refers to the amount of electric energy produced by the generation facility and injected into the grid.

[13] The term "coincident" refers to the output levels produced at the same time by more than one generator or more than one type of generators.

resulting generation and storage dispatch patterns have become increasingly variable. Assigning a single (standalone) injection capability to any location is unrepresentative of the actual capability at that location given that the injection capability range has a wider spread due to the highly variable dispatch patterns associated with wind and solar resources. Determining a maximum injection capability is akin to marking one bookend of the wide range of variable injection capability resulting from myriad combinations of variable loads and variable generation and storage dispatch patterns. This is also the reason it is not appropriate to simply add up standalone injection capabilities for purposes of determining the simultaneous injection capability of the transmission system.

The transmission system is interconnected as a network, and generation injection or storage at one location on the system more often than not changes the injection capability at other locations, e.g., generation injections at Pawnee could decrease the generation injection level at Missile Site and vice versa. The generation injection capability values can change when Public Service performs additional transmission studies, whether for clustered Generator Interconnection Requests or for ERP portfolio alternatives, or simply when the projected system conditions change.

Transmission Service Agreements

Public Service is party to a number of transmission service or "wheeling" agreements that are not specifically tied to PPAs. For example, Public Service has a number of retail and wholesale load centers residing within the PRPA, WAPA, and Tri-State transmission systems, and acquires network integration transmission service from each of these utilities pursuant to their open access transmission tariffs ("OATT").

The vast majority of Public Service's owned and purchased resources are located within the Public Service transmission system and have no specific wheeling agreement associated with them. Rather, in accordance with the requirements of FERC, the transmission function of Public Service maintains a list, posted on its OASIS website, of designated network resources that are delivered to Public Service's native load customers. This list is updated when a new resource has completed the required transmission study processes and is placed in service, and when a PPA terminates or a generator is retired.

Public Service has a long-term firm point-to-point service agreement with the transmission function of Public Service for the purchase of 188 MW of transmission service from the San Juan/Four Corners/Shiprock region to the Craig switchyard. This path is used to purchase capacity and energy at the Four Corners/San Juan marketplace. It is also anticipated that this path will be used to import economic energy from other Western Energy Imbalance Market partners when Public Service joins that market in 2022. This contract terminates on January 31, 2025 and may be renewed in accordance with the OATT.

Public Service also maintains short-term firm and non-firm transmission service agreements with over 30 transmission service providers, pursuant to the providers' OATTs. These agreements are not transaction-specific and have no specified MW quantity or term. Rather, these "umbrella" agreements allow (and are required in order for) Public Service to request and purchase short-term transmission services via the providers' OASIS sites. Such purchased transmission services are used to transmit short-term purchased resources to the Public Service system, or to facilitate off-system sales.

Coordination Agreements

Public Service purchases short-term energy and capacity under two coordination agreements: the Western Systems Power Pool ("WSPP") Agreement and the Northwest Power Pool ("NWPP") Reserve Sharing Program Agreement. The WSPP Agreement represents a marketing pool involving many supplier organizations throughout the United States. Many of Public Service's short-term firm and economy purchases are made under, and pursuant to the terms of, the WSPP Agreement.

Along with participating in the WAPA Balancing Authority, Public Service entered the NWPP Reserve Sharing Program in September 2019. The NWPP Reserve Sharing Program Agreement provides for sharing of contingency operating reserves among interconnected electric utilities operating in the Western Interconnection. There are presently 22 participating Balancing Authorities in the NWPP Reserve Sharing Program. By pooling their contingency reserves, these utilities are able to carry less contingency reserve capacity than if they operated independently. Under the NWPP Reserve Sharing Program Agreement, Public Service can call on and purchase contingency reserves (spinning and non-spinning), and the energy associated with such reserves, when they are activated in response to a sudden system disturbance. Public Service can also purchase emergency assistance under the NWPP Reserve Sharing Program Agreement.

2.9 RELIABILITY PLANNING, RESERVE MARGINS AND CONTINGENCY PLANS

In this Section, the Company provides information regarding its planning reserve margin, system reliability planning and assessment, and contingency plans as required by Rule 3609(a)-(c).

Reliability Planning at Public Service

Public Service strives to provide electric service at all times to our firm load customers. To accomplish this, the Company works to maintain an adequate supply of electric generation to meet the expected maximum demand of our customers (i.e., the "peak" demand or load) for a reasonable set of unforeseen events (power plant outages, higher than expected load etc.) To maintain service to firm load customers, Public Service utilizes a combination of measures and practices, each focusing on different time horizons – real-time, mid-term, and long-term.

Real-time

Ultimately it is the real-time status of the system that determines whether generation supply is sufficient to maintain service to firm load customers. Real-time in this context refers to the measures and practices the Company employs each day in operating the electric system, including carrying sufficient operating reserves to ensure that ample resources are available to serve load. Operating reserves are generation capacity that is either on-line and unloaded, i.e., spinning, or that can be brought on-line and synchronized to the grid in short order.

As a member of the NWPP Reserve Sharing Group, Public Service carries operating reserves in accordance with the NWPP established methodology. Public Service's contingency reserve obligation in the NWPP is dynamic based on several factors, including the size of the largest contingency in the PSCo BAA, and real time transmission available to deliver reserves from other NWPP members.

As a part of managing the real-time balance between load and generation on the system, the Company continuously monitors the current level of wind generation and ensures that a sufficient level of flexible resources is available to maintain system reliability in the case of a large wind ramping event. The level of flexible resources required for this purpose is a function of the amount of wind generation.

Operating Reserve is a general term used to define the combination of various reserves that are needed to perform in the duty of balancing generation and load. Operating Reserve for Public Service is made up of Contingency Reserve, Regulating Reserve, and Flex Reserve. Contingency Reserve is the reserve maintained to respond to the unplanned trip of generators. Contingency reserve is provided by resources that can respond very quickly to an event, within 10 minutes. Contingency reserves are split between spinning (i.e., connected to the grid) and non-spinning resources. The amount of contingency reserve that is to be carried by the Company is determined by the NWPP.

Regulating Reserve is the reserve maintained to respond to intra-hour changes in load and non-Variable Energy Resource (“non-VER”) and Variable Energy Resource (“VER”) generation output, and it is also comprised of various types of service. The two types of regulating reserve are “fast moving reserve” and “load following reserve.” To manage minute-to-minute changes in load and non-VER and VER generation on the system, Public Service carries fast-moving regulation reserve. To manage changes over a 10-minute period, the Company carries load following regulation reserve. The Company recently studied the amount of fast moving and load following regulating reserve required to reliably manage its system and has updated its Open Access Transmission Tariff accordingly.

The last type of Operating Reserve that Public Service carries on its system to maintain reliable service to customers is Flex Reserve. Flex Reserve is held on Public Service generating units to address the impacts of large downward ramping events caused by reductions in wind speed within the PSCo BAA. The Company determines the amount of Flex Reserve required to operate reliably with the wind it has, or will have, on its system. The calculation has evolved over time due to the increasing size of the wind generation on the system and our experience of performing efficient, reliable system dispatch with increasing levels of installed wind generation.

Mid-term

To better ensure sufficient resources are available to meet the real-time needs of the system, Public Service evaluates the need for short-term capacity and energy several months in advance of each summer and winter peak season. In the event that this mid-term supply adequacy evaluation determines that the installed or purchased generation for the upcoming summer or winter peak periods are likely insufficient to achieve a desired reserve margin, the Company will pursue purchasing short-term capacity.

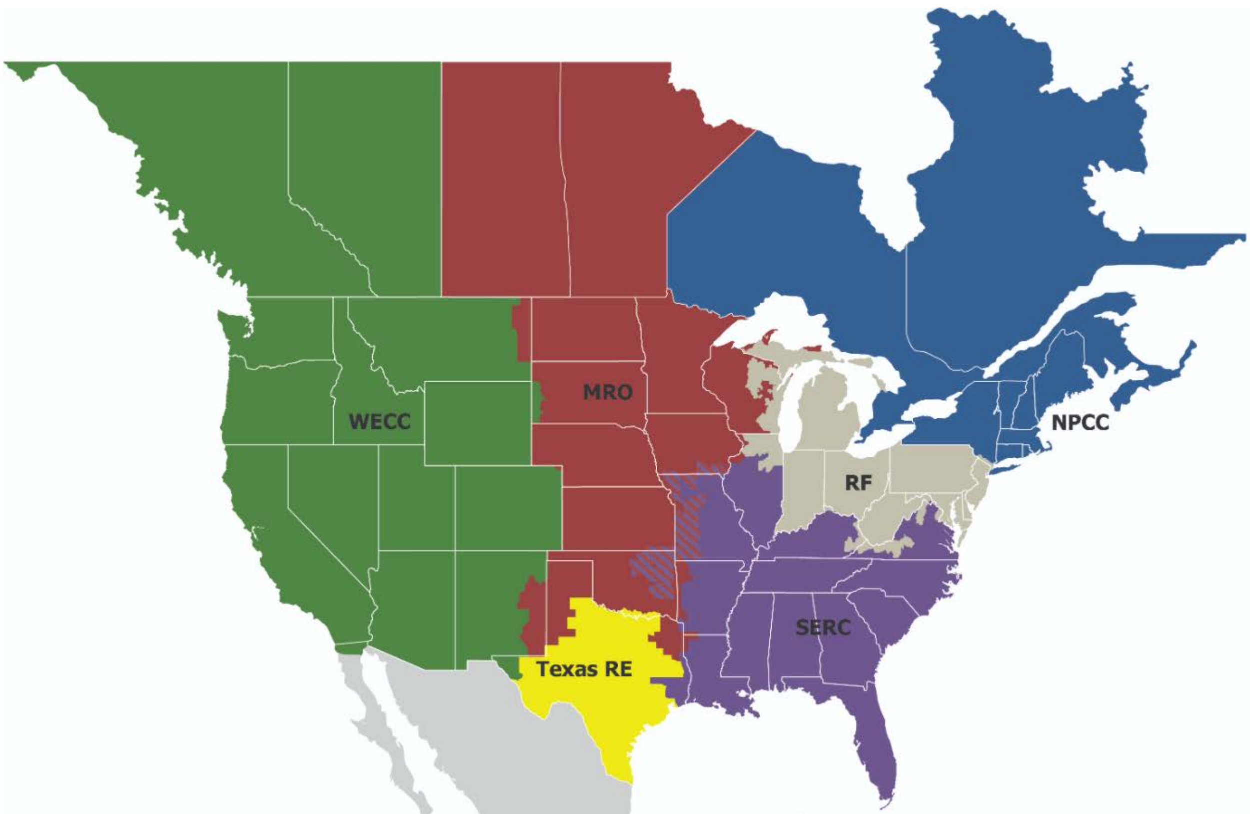
Long-term

Long-term activities involve the acquisition of additional generation resources or demand reduction to meet the long-term electric demand projections. The amount of installed generation capacity in excess of the annual system peak demand is commonly referred to as “planning reserve margin” or “planning reserves.” Long-term in this context refers to a future period of up to 10 years (or longer), over which the Company acquires additional generation supply resources through the Commission’s ERP process. The reserve margin target used in the long-term planning of the system influences the Company’s ability to meet the future mid-term and, ultimately, the real-time capacity needs of the system. The remaining discussion will focus on the “planning reserve margin” Public Service proposes to employ in the acquisition of future resources in the 2021 ERP.

Planning Reserve Background

The reliability and security of the bulk power system is guided and coordinated by NERC. NERC is the Electric Reliability Organization for North America and is subject to oversight by the Federal Energy Regulatory Commission. NERC has many responsibilities including publishing and enforcing Reliability Standards and annually assessing the resource adequacy and operating reliability of the bulk power system. NERC is comprised of six separate Regional Entities. WECC is the Regional Entity responsible for ensuring that Public Service follows NERC Reliability Standards. The various NERC regional entities, including WECC, are shown in Figure 2.9-1.

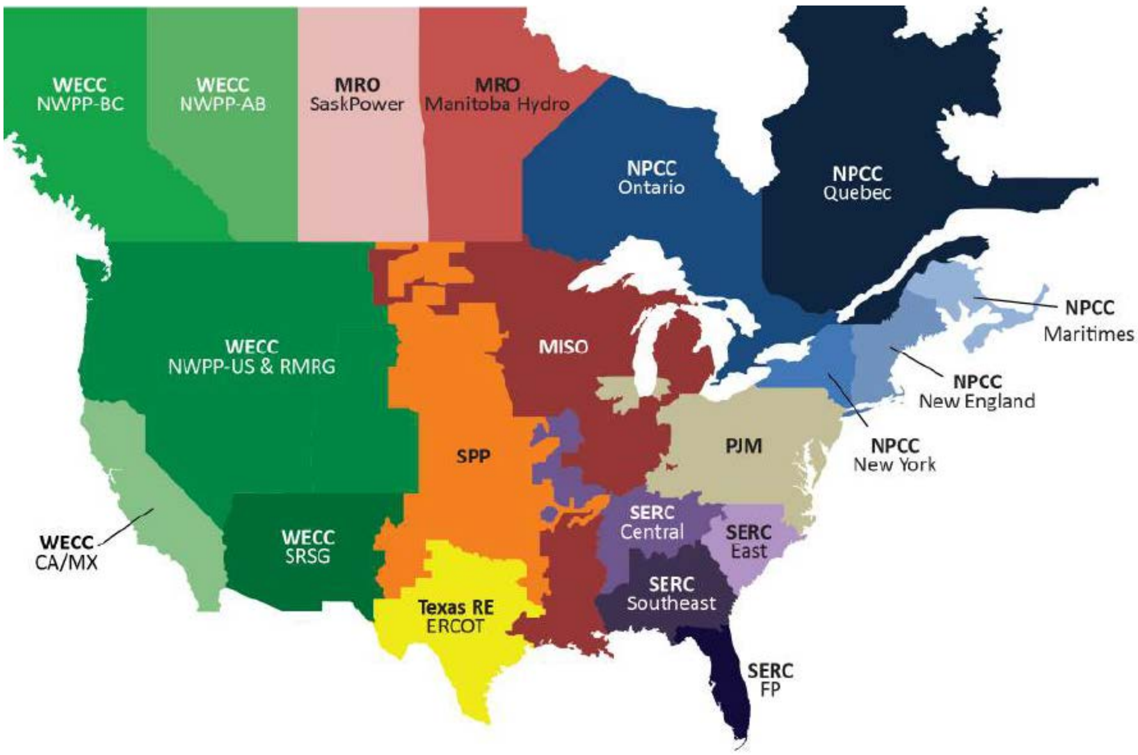
Figure 2.9-1 Regional Entities of NERC



Both NERC and WECC publish annual reports containing planning reserve margins for subregions covering Public Service's system. A planning reserve margin is the amount of capacity greater than the expected firm demand needed to maintain resource adequacy. NERC's annual resource adequacy and operating reliability assessment is called the Long-Term Reliability Assessment ("LTRA") with the latest report published in December 2020.[14] Public Service is within the WECC NWPP-US & RMRG subregion of the NERC LTRA, as shown in Figure 2.9-2 below. The LTRA for this subregion found that anticipated reserve margins of 38% to 42% for the peak demand hour were insufficient to maintain resource adequacy for all hours of the year. This is because planning reserve margins based on the peak demand hour and expected values of demand and generation do not capture the loss of load risk outside of the peak demand hour for systems with high penetrations of renewable generation and storage. There were simulated loss of load hours in July through September one to three hours after the peak demand hour when solar generation had diminished. Specific risks to resource adequacy identified for the Western Interconnection were a reliance on power transfers from neighboring systems during wide-area weather events such as occurred in August 2020. Risks identified but not limited to the Western Interconnection included the need for sufficient flexible generation to integrate the variability and uncertainty of renewable generation and the potential for natural gas delivery disruptions for systems increasingly dependent on natural gas.

[14] Report Available at:
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf.

Figure 2.9-2 Subregions of Long-Term Reliability Assessment



WECC does not publish recommended or required planning reserve criteria for its member systems, but rather allows individual member systems (including regulatory commissions) to adopt their own planning reserve criteria. WECC does, however, perform an annual Western Assessment of Resource Adequacy ("Western Assessment") of its member systems. The most recent Western Assessment was published in December 2020.[15] The purpose of the Western Assessment is to provide an independent and interconnection-wide analysis of resource adequacy. The Western Assessment identifies the potential for electricity supply shortages using probabilistic analysis at the hourly level, and reports its findings for the following 4-year period. During these annual assessments Public Service provides WECC with detailed information regarding the Company's electric supply system including:

- Forecasts of demand
- Existing, Retiring, and Expected Resources and associated ratings
- Historical hourly renewable generation and demand data
- Transmission information

[15] Report available at: https://www.wecc.org/ResourceAdequacy/Pages/default.aspx

WECC combines this data with that of other member systems to model at the interconnection-wide level and within five subregions of the interconnection. Public Service is within the NWPP Central ("NWPP-C") subregion. The NWPP-C subregion includes Colorado, Utah, Nevada, and portions of Idaho, Wyoming, and California.

Figure 2.9-3 Subregions of the Western Assessment of Resource Adequacy

The Western Assessment uses probabilistic analysis across a range of assumptions of resource availability and demand to determine required planning reserve margins for every hour of the study to maintain resource adequacy. Maintaining resource adequacy is defined as having sufficient resources to expect a loss of load event no more than once every 10 years. For the NWPP-C subregion in 2021, the Western Assessment found that a planning reserve margin of 21% maintained resource adequacy for half of all hours and a planning reserve margin of 32% maintained resource adequacy for all hours. The NWPP-C subregion does not have enough resources to maintain resource adequacy for all hours and requires imports from other subregions. The Western Assessment results do not reflect the planning reserve margins approved for use by individual utilities (including Public Service) and are not intended to supplant these approved utility-specific planning reserve margins; however, they do provide a useful cross-check for comparison.

Reliability Assessment of Clean Energy Plan Portfolios in Phase I

As shown in Figure 2.9-4, system reliability was factored into the development of the Phase I portfolios in an iterative process that involved inputting various reliability requirements upfront into the EnCompass modeling process, post-modeling reliability review of model output/results, and then adjusting model inputs if needed and then rerunning the adjusted model. Reliability requirements from applicable technical studies, including planning reserve requirements, flex reserve requirements, and ELCC capacity credit, and as discussed in more detail below, were applied within the EnCompass modeling of all portfolios.[16] In addition to the results of these technical studies, the operating requirements established by the NWPP Reserve Sharing Group were reflected as inputs into the modeling process.

The post-modeling reliability review process involved reviewing hourly model output for 2030. A team of Company subject matter experts reviewed the overall generation composition of portfolios from both a generation reliability perspective and a transmission reliability perspective. For the generation reliability review process, the hourly data review process for generation reliability involved an assessment of 8760 (i.e., the number of hours in a year) hourly model output to determine if the model was properly enforcing planning reserve, flex reserve, and NWPP operating reserve requirements. The review also analyzed whether the current gas supply system would be sufficient to reliably supply the hourly volumes and fluctuations in gas burns that the modeling predicted.

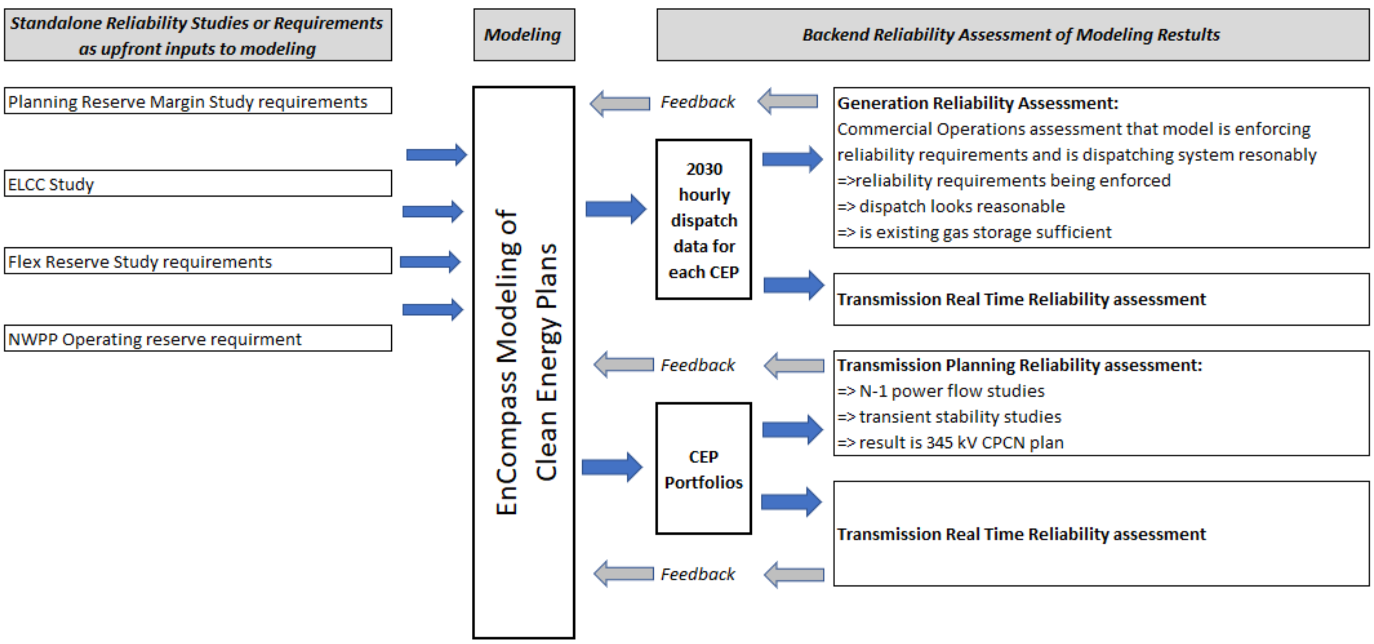
The hourly data review process for real-time transmission reliability also involved an assessment of 8760 hourly model output. The purpose of the review was to determine if the current and planned transmission system could reliably deliver, in real-time, the output of the generation resources in each portfolio to customer load. In addition to this real-time assessment of hourly data, the Company's transmission reliability review and planning process to support this 2021 ERP & CEP filing involved an assessment of the Company's resource planning projections to determine if the planned transmission system expansion could reliably deliver the Company's resource acquisition target to meet the 2030 emission reduction goals.[17] If these reliability reviews identified that a particular reliability input requirement needed adjusting, then the adjustments would be made, the model would be rerun, and the output would be reviewed to see if the adjustment worked as intended. For example, if certain generating units were viewed as contributing more spinning reserves than they should or could, the modeling inputs that define a generating unit's contribution to spin would be adjusted and the model

[16] See Section 2.18 for these studies.

[17] This planned transmission eventually became the Colorado's Power Pathway project that the Company filed a CPCN for on March 2, 2021.

would be rerun. In addition, there are certain aspects of this type of modeling that are a function of the model output and therefore cannot be fully captured through the various upfront inputs into the model. For example, the required transmission upgrades that might be needed to reliably deliver the new generation resources that were added to the system as a result of the optimization cannot be known until after the model is run. In this instance, the cost for any additional transmission requirements would be a post-modeling addition to the cost of the portfolio.

Figure 2.9-4 Overview of Reliability Assessment Framework



Modeling Implementation and Reliability Inputs

Planning Reserve Margin

For purposes of developing the 2021 ERP & CEP, the Planning Reserve Margin within the EnCompass model was set to 18% for the peak demand month of the year (July) on a long-term basis. The model then developed expansion plans to meet this reserve margin as a minimum threshold requirement. For the years prior to 2025 where the Planning Reserve Margin Study indicated higher levels of reserve margin are required, a “generic short-term seasonal purchase” was included to cover any MW required in excess of 18%, so that the model would only add generic resources on a long-term basis to meet 18%.

Effective Load Carrying Capability

For resource planning purposes, different generation technologies provide different levels of their nameplate generation capacity rating toward reliably serving customer load. Effective Load Carrying Capability ("ELCC") is a measure of how much of a resource's nameplate capacity should be included on the Company's load and resources table. ELCCs for non-dispatchable, intermittent generation technologies (such as wind and solar) and for energy-limited resources (such as storage) can be significantly less than 100%.

Flex Reserve

Flex Reserve (wind driven) and Regulation (wind and solar driven) ancillary service requirements are directly related to the amount of new wind and solar added in the expansion plan. However, the ancillary service requirements are pre-run inputs into the model and are not able to be dynamically resized within the model as the expansion plan is being developed. Thus, to fully represent each specific plan, an iterative approach to sequentially develop a plan, resize the Flex and Regulation, and repeat until they match/converge was required.

Given the generic nature of the Phase I plans, as well as the time constraints required to do iterations with the large number of Phase I scenarios and sensitivities, this process was not fully executed for Phase I. During the preliminary runs completed by the Company leading up to the final modeling, a relatively consistent and clear pattern of generic additions emerged. The company developed 4 different "requirements" shapes through 2050 based on these expansion plan results and applied them to the appropriate scenarios for Phase I. Upon inspection of the final plans, these proved to be reasonably consistent and valid for the final modeling results. The four versions of the requirements were:

- $0/ton CO_2 ERP Portfolios
- $0/ton CO_2 CEP Portfolios
- SCC CO_2 ERP Portfolios
- SCC CO_2 CEP Portfolios

NWPP Operating Reserves

The NWPP Operating Reserves requirement is an hourly value that is determined by a complex formula including Public Service hourly load and generation, the remainder of the balancing authority's hourly load and generation, hourly real-time available transmission support via the TOT tie lines, and the most severe single contingency ("MSSC") on the system, which is typically either Comanche 3 or the flow on the Rush Creek gen-tie line. To develop a reasonable proxy of this requirement, static hourly curves were developed for each of these variables from the associated model input data and were used to develop an hourly proxy shape for total operating reserve requirements using the actual NWPP formula. Within the model, one half (50%) of the operating reserves were required to be carried by spinning reserves that could be carried by online resources or 10-minute responsive quick-start units.

Planning Reserve Study for the 2021 ERP

For the 2021 ERP, Public Service will utilize a planning reserve margin target of 18% in assessing the need for additional power supply resources. This 18% value will be applied to the Company's projection of annual firm peak demand[18] over the RAP to determine the amount of additional power supply the Company should acquire on a long-term basis in this ERP in order to maintain acceptable long-term resource adequacy.

The 18% planning reserve margin target for the Public Service system is the result of an updated Planning Reserve Margin Study which can be found in Appendix A. This study was completed by Astrapé Consulting on behalf of Public Service. The probabilistic study evaluated every hour of future study years 2021, 2023, 2026, and 2030 for the capacity required to expect no more than 1 loss of load event in 10 years. The inputs to the study included 39 historical years of weather-correlated demand, wind, and solar hourly profiles and 10 years of generator outage hourly profiles to capture the variability in resource availability and demand. The planning reserve margins calculated for the study years varied from 17.4% to 19.3% depending on the levels of dispatchable, renewable, storage, and demand response resources within the study year.

Public Service will implement the results of the Planning Reserve Margin Study in this 2021 ERP by acquiring, through the Phase II process, generation resources as necessary to achieve, at a minimum, 18% reserve margin plus an additional planning reserve in accordance with the Company's wholesale contract with IREA and Holy Cross Energy (estimated to be up to 48 MW). In addition to the resources acquired through the Phase II process, the Company will acquire additional resources through short-term market purchase as needed to achieve up to a 19.3% planning reserve level for certain years of the RAP as reflected in Table ES1 of Appendix A.

Effective Load Carrying Capability (ELCC) Study for the 2021 ERP

Appendix E is an updated ELCC study report. The updated study determined ELCC values for:

- Solar, wind, hydro, and storage resources expected to be operational by 2023 including existing resources and those resources acquired from the 2016 ERP;
- Incremental additions of solar and wind resources across broad geographic regions and for incremental additions of geographically diverse portfolios of solar and wind; and

[18] Annual firm peak demand to which the 18% reserve margin target will be applied is represented by taking the 50th percentile forecast of native peak demand and subtracting the effects of the Company's interruptible load programs. The 18% planning reserve margin continues past the RAP through the entire Planning Period.

- Incremental additions of storage on a standalone basis and with incremental additions of solar and wind.

For Phase I modeling, the EnCompass model was populated with updated ELCC values for the Company's existing solar, wind, hydro, and storage resources. For portfolio creation, incremental ELCC values from the study for the generic solar, wind, and 4-hour storage resources were used. For the solar and wind generics, the geographically diverse ELCC study results were used. In order to capture the impacts of declining ELCC values with incremental resource additions, two tranches of solar ELCC, wind ELCC, and storage ELCC were employed; higher ELCC values were assigned to the first tranches of solar, wind, or storage selected by the model and then lower ELCC values were assigned to all other incremental resources. However, for the "No New Gas" sensitivity, a third tier for solar, wind, and storage was added to better represent the impact of declining ELCC on resource mix for this sensitivity.

Operating Reserves for the 2021 ERP

The real-time status of the Company's electric system determines whether supply is sufficient to maintain electric service to firm load customers. Real-time in this context refers to the measures and practices the Company employs each day in operating the electric system which entails carrying sufficient Operating Reserve to ensure that ample generating resources are available to accommodate total firm load, higher than expected firm load, changes in firm load (minute to minute and hour to hour), unexpected outages of generating units (forced outages), and variability in the output of renewable resources. These real-time measures and practices focus on maintaining sufficient levels of Operating Reserve.

Operating Reserve is a term used to define the combination of various reserves that are needed to perform the duty of continuously balancing generation and load throughout the day. Operating Reserve for Public Service is made up of Contingency Reserve, Regulating Reserve, and Flex Reserve.

Contingency Reserve is the reserve maintained to respond to the unplanned trip of generators or transmission elements and is provided by resources that can respond very quickly to an event, within 10 minutes. Contingency Reserve is split between spinning (i.e., connected to the grid) and non-spinning resources. The amount of Contingency Reserve that is required to be carried by the Company is determined by NWPP. In general, NWPP requires members to maintain Contingency Reserve equal to the greater of 3% of the balancing area load plus 3% of the balancing area generation or the most severe single contingency ("MSSC") with the additional requirement that at least half of the requirement be provided by spinning reserves. The remainder of the Contingency Reserve requirement not provided by spinning reserves may be provided by non-synchronized resources available within 10-minutes. The MSSC for Public Service will typically be either the Rush Creek Gen-Tie or the 750 MW

Comanche 3 unit. The portion of any resource used to meet Contingency Reserve cannot be used to meet Regulating Reserve or Flex Reserve.

Regulating Reserve is the reserve maintained to manage short-term uncertainty and variability in load and solar generation output. The two types of Regulating Reserve are "fast moving reserve" and "load following reserve." Public Service carries fast-moving regulation reserve to manage minute-to-minute changes in load and solar generation output on the system. To manage changes over a 10-minute period, the Company carries load following regulation reserve. Regulating Reserve can be provided by the unloaded portion of dispatchable generation that is synchronized to the grid and is not being used to provide Contingency Reserve or Flex Reserve. Regulating Reserve is constantly cycling back and forth between a reserve state and deployment as energy. For this reason, energy limited resources such as battery energy storage and demand response programs are not used for Regulating Reserve.

Flex Reserve Study for the 2021 ERP

The Company performed an updated Flex Reserve study for this 2021 ERP, which is provided as Appendix B and a Supplemental Flex Reserve study provided as Appendix C. Flex Reserve is held on the Public Service system to address short-term variability and uncertainty in wind generation as well as the impacts of large downward ramping events caused by reductions in wind speed within the PSCo BAA. The Flex Reserve requirement is comprised of three components: (1) a Reg-Up component; (2) a 10-minute component; and (3) a 30-minute component. The amount of wind generation operating in the BAA determines the total amount of Flex Reserve that is required each hour of a day. The Reg-Up component is 15% of the total Flex Reserve requirement and must be provided by the unloaded portion of dispatchable generation that is synchronized to the grid and is not an energy-limited resource. The 10-minute component is 45% of the total Flex Reserve requirement and can be provided by the portion of any on-line or off-line resource which can respond within 10 minutes. The 30-minute component is 40% of the total Flex Reserve requirement and can be provided by the portion of any on-line or off-line resource which can respond within 30 minutes. The portion of any resource that is providing Flex Reserve is not allowed to also provide either Regulating Reserve or Contingency Reserve.

Contingency Plan

Rule 3609(c) requires the Company to develop contingency plans for the RAP given actual circumstances may differ from the most likely estimate of future resource needs. Rule 3609(c) requires the Company to provide, under seal, a description of its proposed contingency plans for the acquisition of additional resources if actual circumstances deviate from the most likely estimate of future resource needs developed pursuant to Rule 3610; or, replacement resources in the event that resources are not developed in accordance with a Commission-approved plan under Rule 3617.

Public Service recognizes that matching electric power supply with customer demand will not always proceed according to plan. Problems can arise as a result of delays in the in-service dates of new generation facilities, contract negotiations with power suppliers can breakdown, and unanticipated increases in customer demand can arise that Public Service is obligated to serve. While it is impossible to anticipate everything that can occur in the resource acquisition process, we can anticipate the more common situations and develop plans to address them.

In the discussion below, the Company describes what it believes to be the most likely situations the Company might face in the resource acquisition process and identifies contingency alternatives available to address them. The discussion focuses on events or situations that create the potential for a capacity shortfall if corrective action is not taken.

Contingency Events

Public Service anticipates that the more relevant and probable contingency events will include, but are not limited to:

1. Failed contract negotiations with winning bidders
    a. Bidders withdrawing proposal
    b. Bidders seeking revised terms and/or prices from those in their bid
2. Project development delays or cancellation
3. Transmission development delays
4. Higher than anticipated customer demand

Contingency Plan Options

The following is a list of options available to Public Service to remedy any unanticipated resource shortfall:

1. Initiate negotiations with other / replacement bidder(s)
2. Issue a targeted RFP to replace a selected project that has failed
3. Accelerate the in-service date of other selected projects
4. Purchase short-term capacity from off-system, existing generation
5. Issue additional non-targeted RFP(s) to satisfy anticipated shortfalls
6. Construct and own additional new generation facilities
7. Arrange temporary generation
8. Implement interim Load Management / Customer generation plans
9. Modify contracts with existing power suppliers
10. Sole source with an IPP to construct additional generation
11. Acquire incremental Distributed Energy Resources (including demand-side management resources)
12. Some combination of (1) through (11)

Critical Factors

Two critical factors dictate whether a corrective action provides a viable solution for a particular contingency event. These factors are:

1. The magnitude of the potential resource shortfall; and
2. The timing associated with the potential capacity shortfall – both the lead-time to the contingency and the duration of the event.

The magnitude of an anticipated capacity shortfall dictates the available options Public Service can pursue. For example, a capacity shortfall of 50-100 MW might be addressed through contracting short-term purchases from off-system existing generation. Short-term capacity purchases would likely be ineffective in addressing a larger shortfall, such as 500 MW for example.

Similarly, the timing of an anticipated capacity shortfall dictates the number of available options Public Service can pursue. Timing in this case includes both the duration of the shortfall and when it is expected to occur. Capacity shortfalls projected to occur within a year for example would likely exclude the option of constructing new generation and transmission facilities. By contrast, a capacity shortfall projected to occur several years in the future could be addressed through a variety of actions including new construction, initiating negotiations with other bidders, or issuing a targeted RFP.

Likewise, a delay of a new generation resource or of the transmission needed for a new resource might best be addressed by a temporary or interim solution, like temporary generation facilities, short-term purchases, or interim load management, as opposed to the permanent addition of another new generation project or new Company-constructed and owned generation facilities – unless there were a long-term need for additional resources.

Corrective Actions

In the event Public Service faces a capacity shortfall situation, the appropriate course of action will depend largely on the specifics of the shortfall itself (i.e., magnitude and timing), as well as a variety of other factors (e.g., market conditions and other acquisition activities underway). As such, Public Service will always need to exercise judgment as to how to proceed when deciding what corrective action to pursue. For this reason, the Public Service contingency plan reflects a large degree of flexibility in how the Company plans to address various contingencies. Table 2.9-1 lists several possible approaches for addressing contingencies that might require corrective action over the RAP. This hierarchy depends on how long before the event Public Service becomes aware of the contingency, the expected duration of the contingency (e.g., a delay versus the permanent loss of a planned resource), and the magnitude of the contingency.

Table 2.9-1 Hierarchy of Contingency Plan Alternatives

1	Short-term capacity purchases	Save for "late breaking" contingencies for which there might not be time to use one of the following corrective actions.
2	Use alternative bids	If the contingency becomes known before Public Service has released bidders from their obligation, Public Service would use this corrective action. This corrective action is most appropriate for replacing 1st winning bids that drop out soon after selection or do not reach successful contract completion.
3	Accelerate in service date of resources for which contracts have been executed or for self-build projects already been approved	If the contingency becomes known sufficiently ahead of time, negotiate an earlier in-service date for a resource planned for later in the acquisition period. This corrective action is most appropriate for a one to two-year delay in another resource.
4	Public Service builds back-up bids	If the contingency becomes known in time for Public Service to build its own facility, Public Service will self-build a facility to cover the contingency through the use of the back-up bid that will be filed with the Commission at the time the bids for the RFP are due to be submitted to the Company.
5	Issue RFP	An RFP, either targeted for a particular technology similar to the failed bid(s) or a non-targeted RFP open to various technology types, could be issued for expected shortfalls.
6	Sole source with reliable supplier	This option could substitute for Public Service building its back-up bid if time does not permit the Company to complete the necessary construction in a timely manner. Effectively, Public Service would approach an IPP with whom it has had a good working relationship and sole source a new supply either from an existing facility or possibly an expansion of an existing facility.
7	Install Temporary Generation	The Company or an IPP can implement this measure with somewhat less lead-time than the installation of new permanent generation and it is well suited to cover a generation project or transmission delay that may last a year or possibly two.
8	Implement interim Load Management or Customer Generation Programs	Similar to the installation of temporary generation, this measure can be implemented in a relatively short lead-time, e.g. within 6 months, and is well suited to address resource delays.
9	Reduced reserve margin	If the contingency became known too late to add new resources in time and insufficient short-term purchases were available to cover the contingency, Public Service could operate with a reduced planning reserve margin but with the required operating reserve margin for a summer season until one or a combination of the other corrective actions could be put into place.

Public Service and other Xcel Energy Inc. electric utility operating companies have successfully applied many of these contingency actions in the past. Xcel Energy Inc.'s other utility operating companies also have experience with many of these measures and Public Service can draw upon a wide range of resources, experience, and capabilities in order to respond in the most appropriate way to contingencies that might develop during the RAP for the 2021 ERP & CEP.

2.10 ENERGY STORAGE BENEFITS, OPERATIONS, AND MODELING

In this Section, the Company discusses energy storage benefits, operations, and modeling and provides information required by Rule 3604(m) and Rule 3610(b)(III). This Section also provides updated information regarding storage credits and operation as directed by the Commission in Decision No. C18-0761 in Proceeding No. 16A-0396E (the Company's 2016 ERP). These particular requirements are described below.

Rule 3604(m) requires the Company's ERP to include:

> Modeling assumptions and analytical methodology proposed to assess the costs and benefits of energy storage systems including, but not limited to: integration of intermittent resources; improvement of reliability; reduction in the need for increased generation facilities to meet periods of peak demand; and avoidance, reduction, or deferral of investments.

In assessing its need to acquire additional resources, Rule 3610(b)(III) requires the Company to:

> Consider the benefits energy storage systems may provide to increase integration of intermittent resources, improve reliability; reduce the need for increased generation facilities to meet periods of peak demand; and avoid, reduce, or defer investments.

Additionally, in Decision No. C18-0761 (the 2016 ERP Phase II Decision) based on Trial Staff's suggestions, the Commission directed the Company to provide:

> An updated study of storage credits and operation. The study should identify: the preferred storage type(s), expected system benefits (transmission and distribution levels), and the storage value stack.[19]

The discussion below describes:
- The "storage value stack";
- Principal design differences between energy and power storage resources and the design impact on the value stack;
- Quantification of specific value stack values through study reports or EnCompass modeling procedures;
- Existing and planned storage resources in the Company's portfolio;
- The Company's preferred storage types; and
- How storage resources will be evaluated in the Phase II competitive acquisition.

[19] *See* Decision No. C18-0761 in Proceeding No. 16A-0396E, at ¶ 139-140.

Energy Storage Devices

At a most basic level, energy storage devices are useful for moving energy from one time period to another. However, as this movement of energy across time comes with efficiency losses, the addition of energy storage to a system is net energy load added to the system. Cost-effective implementations of energy storage require putting the right type of device, with the right mix of power and energy and the right performance characteristics, in the correct location.

For purposes of the Company's ERP filing and ultimate resource acquisition, storage systems are restricted to those that can serve as a generation/supply-side resource. A useful way to categorize the different types of storage devices as generation resources is through an examination of whether they are designed for power (large MW, but small MWh) or energy (large MW, large MWh) applications.[20] Thus, a storage device's energy to power ratio (which equals its duration) is a useful way to categorize storage devices and track their potential ability to serve the "storage value stack" as described below. In addition, for chemical storage devices (e.g., batteries and reversible fuel cells), the specific cell chemistry has a large impact on the device's performance characteristics.

Storage Value Stack

As indicated above, storage systems for this ERP are restricted to those that can serve as a generation/supply-side resource. Thus, the following are not evaluated: (1) thermal storage resources that might convert electrical energy into thermal energy for sensible heating or cooling purposes, and (2) seasonal fuel storage, such as the storage of natural gas during non-winter months for winter heating usage. Generally, the type of storage contemplated converts electrical energy to some other form (e.g., thermal, mechanical, chemical) and then eventually converts it back into electrical energy to serve electrical system requirements. However, other storage mechanisms can store primary energy in some form other than electricity and then ultimately convert it into electrical energy (e.g., solar thermal power plants with embedded thermal storage). Such resources will be evaluated for acquisition.

System beneficial uses of energy storage devices (i.e., uses that make up a potential storage value stack) can be categorized into four broad categories:[21]

[20] Power is the rate at which energy can be delivered; typically measured in MW. Energy, for a storage device, is the product of the device's power rating (MW) times the device's duration (hrs); measured in MWh.

[21] The categorization and description of the beneficial uses of energy storage devices generally follows that from Sandia Report SAND2015-1002, "DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA", 2015. Available at: https://www.sandia.gov/ess-ssl/publications/SAND2015-1002.pdf.

1. Bulk Energy Services
    a. Energy Arbitrage
        i. Intermittent Generation Curtailment Reduction
    b. Generation Capacity Credit
    c. Dispatchability
    d. Intermittent Generation Integration Credit
2. Ancillary Services
    a. Operating Reserves
        i. Regulating
            1. Fast-moving
            2. Following
        ii. Contingency
            1. Spinning
            2. Supplemental (Non-spinning)
        iii. Flex
    b. Voltage Support
    c. Black Start
3. Transmission Infrastructure Services
    a. Upgrade Deferral
    b. Congestion Relief
4. Distribution Infrastructure Services
    a. Upgrade Deferral
    b. Voltage Support

Below, the Company describes each of these services and indicates whether a Power Device (short duration) or Energy Device (longer duration) is most suitable to provide the service. Typically, Power Devices have on the order of 60 minutes of duration or less; useful Energy Devices typically require 4 hours of duration or longer.

<u>1.a. – Energy Arbitrage (Energy Device)</u>

Storage devices can be used to store electricity ("charging") when costs are low and then deliver that energy back to the electric grid ("discharging") when costs and/or needs for electricity are high. Storage devices with high round-trip efficiency and low variable O&M costs provide the highest potential energy arbitrage benefits.

<u>1.a.i. - Intermittent Generation Curtailment Reduction (Energy Device)</u>

A subset of Energy Arbitrage occurs when "excess" intermittent generation is available relative to load; normally such "excess" intermittent generation is curtailed. Using a storage device in such situations allows a portion of the renewable generation that would otherwise be curtailed to be delivered to load at a later time.[22]

1.b. – Generation Capacity Credit (Energy Device)

For long-term resource planning purposes, energy-limited resources like storage receive less than their nameplate discharge capacity on a loads and resources table; the ability of a storage device to reliably serve long-term forecasted loads can be measured through an effective load carrying capability ("ELCC") methodology. In general, the storage device's duration (calculated as maximum MWh discharge energy divided by maximum MW discharge rate) and inclusion of intermittent generation and other energy-limited resources in the resource portfolio are the primary determinates of ELCC.[23]

For daily operations, the generation capacity credit afforded a storage device is determined through the unit-commit and dispatch process and is more closely related to the shape of the forecasted daily load peak and the forecasted state of charge of the storage device prior to the forecasted peak.

1.c. – Intermittent Generation Integration Credit

Including incremental energy storage to a portfolio that includes intermittent generation will reduce some of the costs imposed on that portfolio by the intermittent generation resources. Appendix D of Volume 2 documents the Company's updated Solar and Wind Integration Cost Study. Incremental storage resources modeled in EnCompass will receive a combined wind and solar integration cost credit (adjusted for natural gas prices as described in Appendix D) applied to the storage resource's discharge MWh as an integration cost credit. See Section 2.14, Modeling Assumptions, for further information regarding the calculation of the solar and wind integration cost for Phase II modeling.

1.d. – Dispatchability (Energy and Power Device)

Inherent to the concept of Bulk Energy Services is the ability for a utility to control the charging/discharging capabilities of the storage device, that is, to be able to dispatch the device in response to changes in net load.

[22] Only a portion of the otherwise curtailed intermittent generation can be delivered to load due to inefficiencies in charging, storing, and discharging storage devices.

[23] See Appendix E of Volume 2 for the Company's most recent ELCC study report that documents the value to be assigned to storage devices during EnCompass modeling.

2.a.i. – Regulating Reserves (Energy and Power Device)

Regulation service is associated with managing the flows of energy between control areas and addressing short-term fluctuations in demand within a control area. Its goals are to maintain grid frequency and meet NERC reliability standards. Regulation service is typically provided through regulating reserves. Regulating reserves have two separate components: (1) a fast-moving component that addresses minute-to-minute uncertainty in net load, and (2) a following component that addresses uncertainty at the 10-minute level (i.e., load following).

2.a.ii. – Contingency Reserves (Energy Device)

Contingency reserves are generally intended to compensate for generation or transmission outages. Spinning reserves must be online (i.e. synchronized to grid frequency) but unloaded and able to respond within 10 minutes. Supplemental reserves may be offline but must be able to respond within 10 minutes; interruptible loads can also be used for supplemental reserve purposes if they can respond within 10 minutes.

2.a.iii. – Flex Reserves (Energy Device)

Flex reserves are an additional operating reserve the Company developed to ensure its compliance with NERC reliability standards given the levels of wind generation in its portfolio. Flex reserves have three components which include: (1) additional regulating reserves from non-energy-limited resources, (2) any 10-minute responsive resources, and (3) any 30-minute responsive resources.

2.b. – Voltage Support (Energy Device)

To manage reactance at the transmission grid level, system operators need voltage support resources to offset reactive effects of grid elements so that the transmission system can be operated in a stable manner. Cost-effective voltage support device usage is site-specific.

2.c – Black Start (Energy Device)

In the event of a catastrophic failure of the grid, active reserves of power and energy within the grid are needed to energize transmission lines and provide station power to bring power plants back online. Black start devices are site-specific.

3.a – Transmission Upgrade Deferral (Energy Device)

Depending upon circumstances, a relatively small MW and MWh of storage could delay the need for a specific transmission system capital investment. Cost-effective transmission upgrade deferrals are site- and situation-specific.

3.b. – Transmission Congestion Relief (Energy Device)

Depending upon circumstances, a sufficient MW and MWh of storage could be placed on either side of a congested transmission element and allow otherwise-curtailed economic generation to be delivered to load. Cost-effective transmission congestion relief opportunities are site- and situation-specific.

4.a – Distribution Upgrade Deferral (Energy Device)

Depending upon circumstances, a relatively small MW and MWh of storage could delay the need for a specific distribution system capital investment. Cost-effective distribution upgrade deferrals are site- and situation-specific.

4.b – Distribution Voltage Support (Energy Device)

Similar to transmission-sited voltage support, voltage support devices can be required to offset reactive loads on the distribution system. Cost-effective voltage support device usage is site-specific.

Caveats to the Storage Value Stack

In the development of cost-effective portfolios that reliably serve the Company's customers, it is important to acknowledge that any generation resources can be used (and are currently used) to meet almost all of the above services. That is, the concept of a "value stack" does not apply only to storage devices; it applies to all generation resources. The one service listed above that can only be served by energy storage is energy arbitrage.

No resource can provide all of the above values at the same time. However, over the course of a year, prudent charge and discharge decisions should allow storage resources to provide several of the services listed above at some point during the year, including:

- Energy Arbitrage;
- Generation Capacity;
- Intermittent Generation Integration; and
- Reserves (under certain specific circumstances).

Some of the potential storage value services shown above are mutually exclusive. For example, Black Start capability must be available with no advance notice in the event of a total grid failure. Thus, a storage device (or the portion of a storage device)[24] dedicated to Black Start service cannot be used for any other service at any time. Similarly, a resource can only be used to provide a single Operating Reserve at a time.

Energy storage, when charged with carbon-free generation, can serve many of these grid services without carbon emissions. However, the same can be true of any thermal generation resource; if the fuel consumed by a thermal generation resource is carbon-free or carbon neutral, those units can also serve these grid services without carbon emissions. If energy storage devices are charged with carbon emitting generation, then it is possible for the use of energy storage to result in a net increase in carbon emissions.[25]

It is also important to realize that the need for many of these services is limited. The incremental energy service value applied to incremental resources experiences diminishing returns; that is, the first tranches of incremental storage provide higher value than later tranches. The Company will have approximately 575 MW of 4-5 hour duration storage in its portfolio by the end of 2022, and the existence of these storage resources reduces the incremental value provided by incremental storage resources.

Company Storage Preferences

Given the current and forecasted state of the Company's electricity system, it sees significantly more potential value in Energy Devices compared to Power Devices. The Company is generally technology agnostic; rather, a device's cost, performance characteristics, commercialization/development status, and any PPA-derived dispatch limitations (if applicable) drive the Company's preferences. Regarding a storage device's main performance characteristics, the Company's preferences are:

- Capacity – 50 MW and greater is preferred from a single source;
- Duration – 4 hour minimum, preference for longer;
- Annual Equivalent Cycles – 200 minimum, preference for more;
- Annual State of Charge – preference for as high as possible;
- Availability – preference for as high as possible;
- Ramp Rates – faster rates are preferred;
- Response Time – shorter times are preferred; and,

[24] When the Company carries Black Start service on its Cabin Creek pumped hydro facility, it maintains a dedicated volume of water in the upper reservoir. The balance of the water in the upper reservoir is available for dispatch.

[25] Whether or not the use of energy storage to meet a grid service results in a net increase in carbon emissions is dependent upon the carbon intensity of the charging generation, the round trip efficiency of the energy storage device, and the carbon intensity of the avoided generation resource that would otherwise have been used to meet the need.

- Co-location with Renewables – standalone devices are preferred if co-location results in operating restrictions (such as dedicated charging requirements or interconnection limitations).

Valuing the Value Stack

Quantification of Bulk Energy and Ancillary Services value for storage devices is conducted within the EnCompass model of the Company's electric system and the balance of the resource portfolio. Several of the services are quantified completely within the model (e.g., Energy Arbitrage and Operating Reserves) based on the impact that the charging and discharging of storage devices during certain hours and the assignment of reserves during other hours have on the dispatch of other dispatchable generators in the portfolio. Quantification of other value streams, although occurring in the EnCompass model, are impacted by calculations that have been conducted outside of the model (e.g., Generation Capacity Credit and Intermittent Generation Integration Costs). For example, values from the ELCC study are used to reduce the Generation Capacity Credit assigned to incremental storage devices from the storage device's nameplate capacity as the EnCompass model solves to ensure peak forecast load and planning reserve margins are met.

Those values in the list that are site-specific (i.e., Voltage Support, Black Start, Transmission and Distribution Infrastructure Services) are not calculated within the EnCompass model; such values would need to be quantified outside the model based on an ad hoc calculation given the specific issues on the local grid intended to be addressed. That is, if a specific distribution system upgrade is targeted for deferral/avoidance through the use of a storage device, the exact nature of the distribution issue needs to be evaluated to determine whether a storage device is a potential solution.

Table 2.10-1 indicates which values in the potential storage value stack are captured within the EnCompass model and which would need to be calculated outside the model, if applicable to a proposed project. The generic storage device in Phase I was assumed to be not capable of providing regulation services, but if a specific bid is submitted in Phase II that is designed to be capable of providing this service, it will be included in the model.

Table 2.10-1 Storage Resource Values Captured Within the EnCompass Model

Potential Energy Device Storage Value	Captured within EnCompass Model
Bulk Energy Services	
Energy Arbitrage	Yes
Intermittent Generation Curtailment Reduction	Yes
Generation Capacity Credit	Yes [1]
Dispatchability	Yes
Ancillary Services	
Operating Reserves	
Regulating - Fast-Moving	No
Regulating - Following	No
Contingency - Spinning	Yes
Contingency - Supplemental	Yes
Flex - 10-Minute Responsive	Yes
Flex - 30-Minute Responsive	Yes
Voltage Support [2]	No
Black Start [2]	No
Transmission Infrastructure Services	
Upgrade Deferral [2]	No
Congestion Relief [2]	No
Distribution Infrastructure Services	
Upgrade Deferral [2]	No
Voltage Support [2]	No
Other	
Carbon Emission Avoidance [3]	Yes

Notes:
1) Subject to ELCC evaluation
2) Site-specific
3) With carbon cap enforced

Sub-Hourly Calculation of Storage Values

The EnCompass model values certain storage values that can be categorized as "sub-hourly"; these include all the Ancillary Services shown in Table 2.10-1. As portfolio selection and costing in EnCompass will be conducted with an hourly representation of load and generation, other unidentified sub-hourly storage values are not captured.

Modeling Process for Renewable Hybrid Facilities

In the Phase I modeling, the Company modeled generic 4-hour duration storage as a standalone resource to simplify the modeling. The Company included a percent reduction from the NREL ATB costs to represent the impact of the current federal ITC as if the storage were paired with solar. However, we did not include any operational restrictions (such as charging only from a renewable resource, or simultaneous discharge limitation due to interconnection size) that are typically found with co-located paired resources.

In Phase II, bid proposals will be modeled in accordance with the actual economics and operational parameters of the specific proposed bids. For example, standalone storage projects will not receive a credit for the federal ITC unless current tax laws are changed so that standalone storage does receive a tax credit.

2.11 ASSESSMENT OF NEED FOR ADDITIONAL RESOURCES

In this Section, the Company provides information regarding its assessment of need for additional resources as required by Rule 3610. Rule 3610(a) requires the Company to assess the need to acquire additional resources during the RAP by comparing the electric energy and demand forecasts developed pursuant to Rule 3606 with the existing level of resources developed pursuant to Rule 3607, and planning reserve margins developed pursuant to Rule 3609. Additionally, as discussed throughout the Company's 2021 ERP & CEP, the need for resources is driven by the requirement to achieve the clean energy target of reducing carbon emissions by 80 percent from 2005 levels by 2030.

Renewable Energy Standard Resources

In assessing its need to acquire additional resources, Rule 3610(b)(I) requires the Company to determine the additional eligible energy resources, if any, the Company will need to acquire to comply with the Commission's RES rules. The Renewable Energy Standard ("RES") requires Public Service to generate a minimum of 30 percent of its energy from qualified renewable energy resources by 2020 (Rule 3654(a)(II)). The Company uses the Renewable Energy Credits ("RECs") generated by these renewable resources to satisfy the minimum annual requirements of the RES. Due to the progressive direction taken by the Company regarding renewable energy over the past decade, the Company has an ample supply of RECs to satisfy the compliance of the RES through 2030. As a result, the push to acquire more renewable energy in this 2021 ERP & CEP is driven by the economic value of renewable energy and its significant contribution toward achieving clean energy targets as opposed to the strict need to comply with the minimum requirements of the RES.

Demand-Side Resources

In assessing its need to acquire additional resources, Rule 3610(b)(II) requires the Company to take into account the demand-side resources it must acquire to meet the energy savings and peak demand reduction goals established under § 40-3.2-104, C.R.S. To that end, the Commission shall permit the utility to implement cost-effective demand-side resources to reduce the need for additional resources that would otherwise be met through a competitive acquisition process pursuant to Rule 3611. See Section 2.4 for details regarding demand-side resources.

Benefits of Energy Storage Systems

In assessing its need to acquire additional resources, Rule 3610(b)(III) requires the Company to consider the benefits energy storage systems may provide to increase integration of intermittent resources, improve reliability, reduce the need for increased generation facilities to meet periods of peak demand, and avoid, reduce, or defer investments. See Section 2.10 for further discussion regarding the benefits of energy storage systems.

Dispatchable Generation Resources

The following discussion emphasizes the continued need to maintain some level of dispatchable generation resources as part of the Company's generation supply fleet. In this context the term "dispatchable generation resources" refers to resources that system operators can start and ramp up or down anytime, day or night, regardless of local meteorological conditions, and can operate continuously for multiple days. This simplified analysis is not intended to supplant the long-term reliability framework of the Company's 2021 ERP & CEP, but to illustrate how portfolios of dispatchable generation, non-dispatchable intermittent renewable generation, and dispatchable limited energy resources (e.g., storage) would be utilized to meet a future meteorological event similar to one that has occurred in the recent past, as explained below.

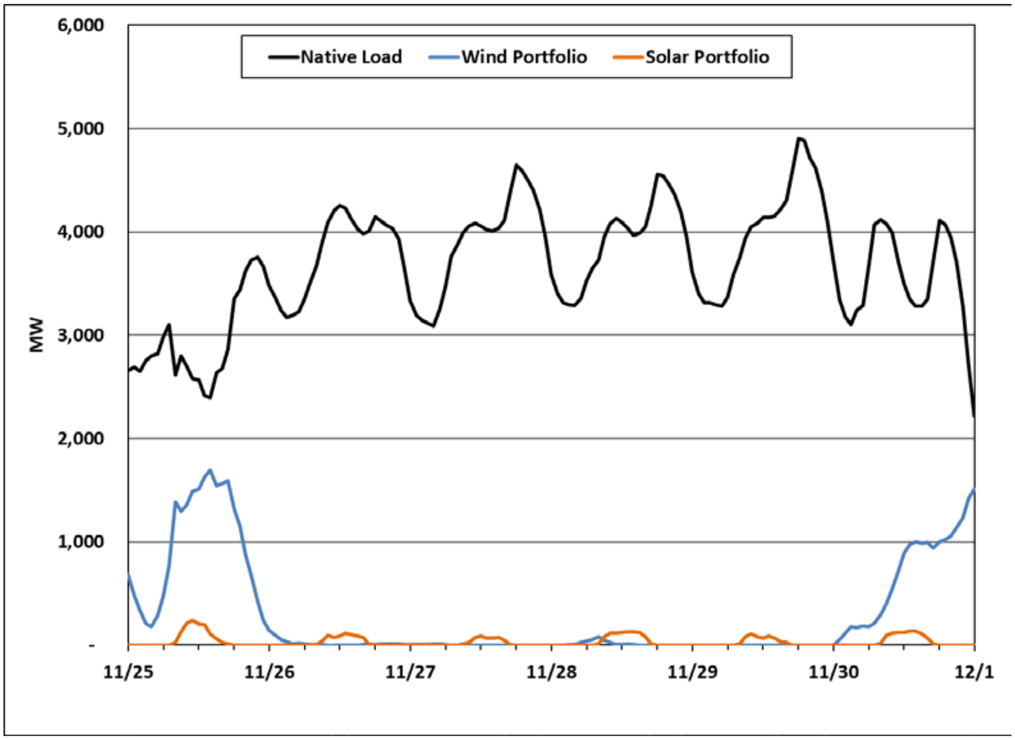
Analysis of a Weather Event – November 25-30, 2015

Figure 2.11-1 below shows the Company's native load and portfolio wind and solar generation for the six-day period beginning November 25, 2015.[26] At that time, the Company's wind portfolio (distributed across the eastern Colorado plains) totaled 2,554 MW and the solar portfolio totaled approximately 375 MW; the Company's solar portfolio was primarily composed of utility solar in the San Luis Valley (135 MW) and customer-sited solar (230 MW) mostly located in the Denver/Boulder load center. During the four-day period starting on November 26:

- Minimum native load did not drop below 3,000 MW,
- Peak load reached 4,900 MW on the fourth day of the event,
- Hourly wind generation capacity factor averaged 0.3%,
- Wind generation never achieved an hourly generation capacity factor greater than approximately 4%,
- Solar generation capacity factor averaged 7% across all hours and 16% across daylight hours, and
- Solar generation never achieved an hourly generation capacity factor greater than 35%.

[26] Native load is the total load that must be met with the Company's portfolio of demand and supply-side resources including the total load of those customers with customer-sited solar or who subscribe to a community solar garden. Portfolio solar includes customer-sited solar and community solar garden generators.

Figure 2.11-1 Native Load and Renewable Generation Late November 2015

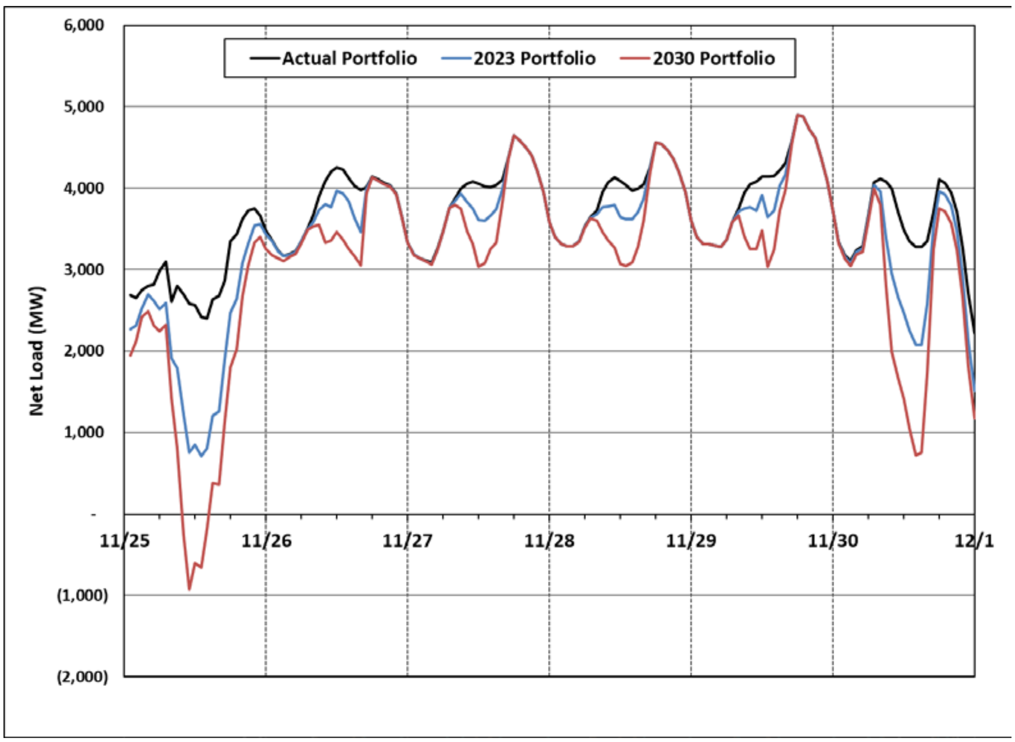


This multi-day, meteorologically induced loss of renewable generation event was caused by a combination of snow and cloudy skies across Colorado, icing on the eastern plains during the start of the event, and low wind speeds at the middle and end of the event. Icing is a condition that occurs near the freezing point and results in the build-up of layers of ice on wind turbine blades that disrupts the airflow around the blades resulting in significant loss in efficiency or, in cases of heavy icing, wind turbine unavailability. While photovoltaic panels can generate electricity at reduced rates during overcast conditions, snow on photovoltaic panels significantly impacts energy production until the snow blows, melts, or slides off the panels. Snow removal can take several days depending upon weather conditions (primarily air temperatures) after snowfall.

Peak and average native load during this event were relatively low compared to winter and summer peak periods, and the Company had sufficient dispatchable thermal generation in its portfolio. However, if the Company has insufficient dispatchable generation to call upon during these types of events in the future, they could represent significant reliability events.[27]

Although storage can be utilized to address short-term losses of wind and solar generation (on the order of 4-6 hours), the amount of storage that would be required to meet customer load for the entirety of this 2015 event is roughly two orders of magnitude greater than would typically be contemplated in the near term. This observation can be illustrated by replotting the same information in Figure 2.11-1 on a net load basis and then estimating what future net loads might look like with future portfolios of incremental wind and solar generation, as shown in Figure 2.11-2 below.

Figure 2.11-2 Net Load During Late November 2015 Meteorological Event with Future Renewable Portfolios



The 2023 portfolio shown in Figure 2.11-2 (shown as the blue line) is the MW level of solar and wind expected to be in-service at that time; this 2023 portfolio has 1,570 MW

[27] As these November 2015 meteorological events were experienced by the entire state, it did not solely impact the Company's fleet of solar and wind generation. Thus, if in the future, surrounding utilities also rely exclusively on wind, solar, and storage, it is doubtful they will be able to meet their own electricity demands during these types of events let alone be relied on to sell "excess" generation to the Company.

of incremental wind and 1,690 MW of incremental solar compared to the actual 2019 portfolio (shown as the black line). The 2030 portfolio shown in Figure 2.11-2 (shown as the red line and representative of the incremental levels of solar and wind in the Company's preferred CEP portfolio) has 2,570 MW of incremental wind and 4,130 MW of incremental solar compared to the actual 2019 portfolio.[28] While the incremental 4,130 MW of solar in the 2030 portfolio does somewhat reduce net load during daylight hours, it does so at only 25% of the solar MW nameplate. As the net load peaks occurred after sunset on 11/27, 11/28, and 11/29, the incremental solar does not reduce the highest hourly net load peaks on those days.

It can be instructional to estimate the total amount of short-duration storage that would be required during this event to meet net load in the absence of any dispatchable generation resources, as a proxy scenario for a system which has only solar, wind, and energy storage resources.

No Dispatchable Generation Scenario

The area under the 2030 net load profile in Figure 2.11-2 from 8 PM on 11/25 to 8 AM on 11/30 (the period during which net load remains above 3,000 MW) is approximately 390,000 MWh. Thus, if the Company's system were modeled with firm import capabilities consistent with the Planning Reserve Margin study assumptions, the storage portfolio would need a minimum capacity of approximately 4,500 MW (to meet the 4,900 MW net peak load on 11/29 less approximately 400 MW transmission import) and 347,000 MWh of energy storage (390,000 MWh – 400 MW * 108 hours).[29]

To meet these storage requirements with 5-hour duration storage resources (i.e., resources with a duration similar to that of the Company's Cabin Creek pumped hydro facility) would require that approximately 69,000 MW of such resources be installed on the Public Service system.[30]

This simple illustration doesn't contemplate that in order to prepare for such an event, storage resources would have had to be completely full and ready for discharge at the start of the event. Thus, the meteorological event would need to be adequately forecasted and prepared for. Also, the portfolio of storage devices could not have been

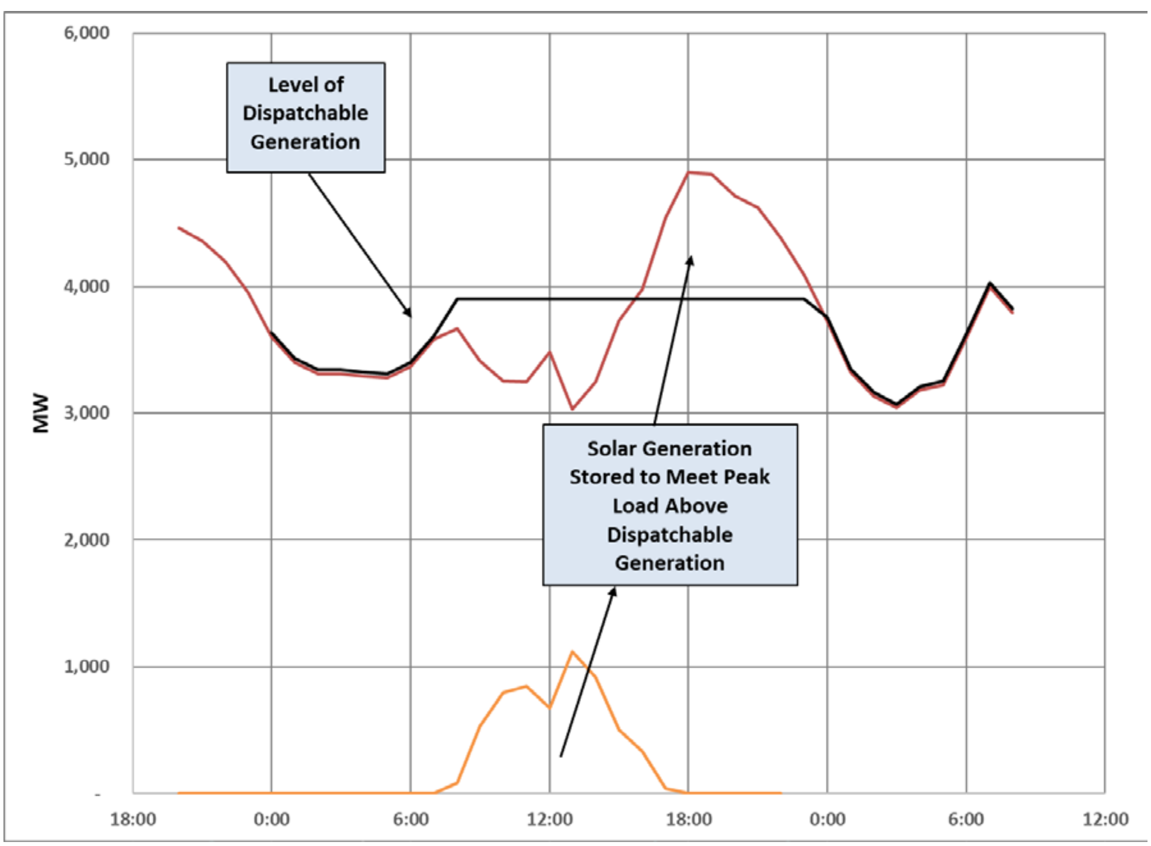
[28] Incremental utility solar and wind generation were modeled off the geographically diverse generic resources described elsewhere in Volume 2. The model also included incremental behind-the-meter and community solar garden generation.
[29] Actual required storage MW would be higher if less than 100% availability for the storage resources is assumed and if reserve requirements were also met with storage.
[30] 347,000 MWh / 5 hours = 69,400 MW.

utilized for any other purpose during the event in order to preserve the stored energy for bulk electric system needs.

Base Portfolio of Dispatchable Generation

Figure 2.11-3 below shows the 2030 portfolio information for 11/29 from Figure 2.12-2, along with the solar generation on that day and an illustrative profile for a certain quantity of dispatchable generation. With this dispatchable generation meeting the bulk of demand, a storage portfolio on the order of 1,000 MW of 5-hour storage could be used to shift solar generation to reliably meet the evening net peak load. As more solar and storage are added, the level of required dispatchable generation in such events could be decreased. However as indicated above, solar capacity factors during such weather events are low, and thus solar is not necessarily an effective source of daytime energy to be stored to meet net peak loads later in the day during these types of events.

Figure 2.11-3 Illustrative Use of Solar, Storage, and Dispatchable Generation to Address November 2015 Meteorological Event



Conclusion

The level of storage required to solely meet net load during weather events like the late November 2015 event described above (69,000 MW) is not reasonably attainable in the near term. Thus, some level of dispatchable or baseload generation will be required for the foreseeable future. In order to reliably plan and operate the electric system, evaluation and recognition of outlier weather events will be critical as more intermittent non-dispatchable generation is added to portfolios to meet carbon dioxide reduction targets.

Carbon-Neutral Peaking Resource Analysis

In Decision No. R20-0108 (Proceeding No. 19A-0409E), the Commission found the future ERP filing requirements in the parties' proposed Settlement Agreement to be just and reasonable (paragraph 63). That Settlement Agreement included the following 2021 ERP filing requirement: "The Company agrees to put forward an analysis of potential utilization of carbon-neutral peaking resources as a part of the Phase I portion of the Company's next ERP."

For this analysis, the Company has assumed that a "carbon-neutral peaking resource" is one that provides dispatchable generation capacity on a long-term planning basis similar to a gas-fired combustion turbine, but with no net CO_2 emissions. As solar and wind are the two most cost-effective and commercially available non-CO_2 emitting generation resources, this analysis focuses on them. However, in order to be able to dispatch solar or wind generation, some element of energy storage must be included. Given the higher ELCC values for incremental solar versus incremental wind in the Company's portfolio, the following analyses focus on solar with storage ("solar hybrid") facilities.

As a result of the 2016 ERP the Company contracted for three solar with battery storage facilities totaling 550 MW of solar and 275 MW/1,100 MWh of storage.[31] As part of the updated ELCC study (Table 6 of Appendix E), the Company is affording these three solar hybrid facilities a total of 430 MW of generation capacity credit (78% ELCC on 550 MW of solar nameplate).[32] Although not explicitly studied, the ELCC study results indicate that if the solar hybrid facilities had been designed with approximately 475 MW

[31] All three of these facilities have a solar to storage MW ratio of 2.0 and 4-hour duration storage. These three facilities are scheduled to be in-service no later than December 31, 2022.

[32] 550 MW * 48% = 264 MW for the solar component and 275 MW * 61% = 166 MW for the storage component. 264 + 166 = 430. 430/550 = 0.78.

of battery capacity instead of 275 MW, the solar hybrid facilities would have received 100% ELCC credit calculated against the solar nameplate MW.[33] Such facilities would meet the definition posited above for a carbon-neutral peaking resource.[34]

The calculations above assigned the solar portfolio average ELCC to the three solar facilities. However, the ELCC study report clearly documents the decline in ELCC for both incremental solar and incremental storage. Figure 4 in the study report shows that the ELCC to be attributed to the next 500 MW tranche of solar is approximately 25%. Figure 10 in the study report shows that the ELCC to be attributed to the next 500 MW of standalone 4-hour storage is approximately 50%. Thus, if a solar hybrid facility is one designed with no more storage MW than solar MW, it is not possible to achieve 100% ELCC solar hybrid facilities in the Company's portfolio.

The storage components of a solar hybrid facility can, of course, provide other values other than just generation capacity credit. The Company lists the various other value streams that storage resources will be afforded in the Phase II competitive solicitation in Section 10. Thus, although solar hybrid and wind hybrid facilities may not be able to provide 100% ELCC credit to the Company's portfolio of generation and storage resources, they can still be part of cost-effective, reliable portfolios that help the Company achieve its carbon reduction targets.

[33] In order to provide 550 MW of total generation capacity credit, the solar component would need to provide 286 MW. Assuming 60% ELCC for incremental storage, 286/0.6 = 477 MW.

[34] There is no assurance, however, that had the three solar hybrid projects been bid with higher levels of storage they would have remained cost effective resources against other bids in the competitive solicitation.

2.12 LOAD AND RESOURCE ASSESSMENT

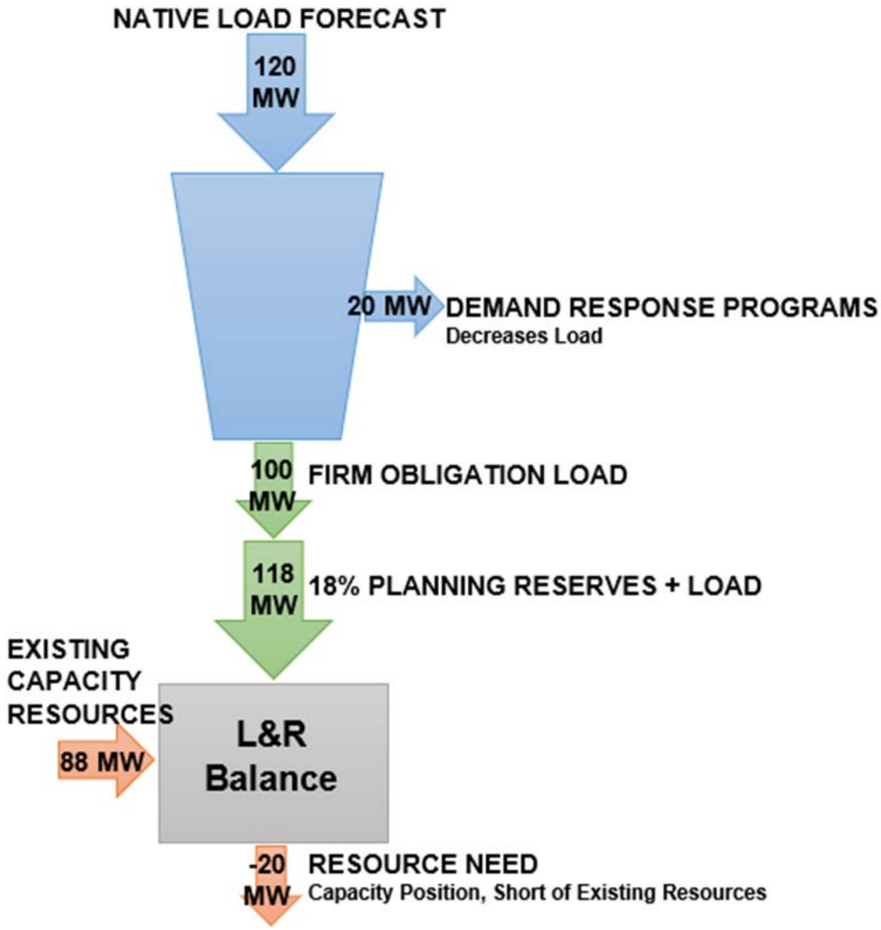
<u>Reliability/Capacity Need Assessment</u>

By comparing the forecast of electric demand with the existing/planned level of installed generation resources and planning reserve margins over the RAP, the Company determines whether there is a need for additional generation capacity on the system. This assessment is commonly referred to as a “load and resource balance” or “L&R.” Over the course of this 2021 ERP process, the Company will provide L&R projections in both Phase I and Phase II. These Phase I and Phase II L&R projections serve different purposes and are expected to vary as described below.

- <u>ERP Phase I L&R</u> – developed and provided at the time the Company files its 2021 ERP. Its primary function is to provide an initial projection of capacity needs (i.e., resource need) that: (1) are used in the modeling of ERP and CEP portfolios, and (2) could be filled in the Phase II acquisition process. The Phase I L&R utilizes the Company’s December 2020 forecast of firm electric demand to represent the “load side” of the balance and existing generation resources as well as planned generation resources to be acquired to represent the “resource side” of the balance. The Phase I L&R is not intended to be the definitive representation of the resource needs the Company will fill in the Phase II competitive resource acquisition process.
- <u>ERP Phase II L&R</u> – developed prior to receipt of bids in the 2021 ERP Phase II acquisition process to represent the resource needs to be filled through that process. This Phase II L&R is certain to show a different level of resource need than that shown in Phase I. This is due to the fact that the Phase II L&R will not only reflect an update to the Company’s demand forecast, but also the Commission decisions from Phase I of the 2021 ERP and other proceedings that impact the determination of resource need. These could include for example Phase I ERP decisions related to the Company’s demand forecast methodology, ELCC levels for intermittent generation resources, and the Company’ planning reserve margin. By updating the L&R balance at the time of the Phase II competitive acquisition process, the Company will better ensure that we acquire the appropriate amount of generation resources to reliably serve the peak demands during the RAP.

Figure 2.12-1 provides an illustrative diagram of the Company’s assessment of the need for additional generation capacity.

Figure 2.12-1 Illustrative Diagram of Assessment of Need



Note: The values in this figure are illustrative.

The resource need assessment accounts for the reduction in peak demand resulting from the Company's demand response programs. The resource need or capacity position is then a result of existing resources less the load and reserves.

ERP Phase I L&R

Table 2.12-1 provides the ERP Phase I L&R projection of resource capacity need.

Table 2.12-1 Load and Resources Table (MW)

	PSCo Summer L&R Table (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	
1	Owned Coal	1,980	1,980	1,655	1,655	1,655	1,278	1,278	1,278	1,278	1,278	
2	Purchased Coal	150	150	-	-	-	-	-	-	-	-	
3	**Total Coal-Fired Generation**	**2,130**	**2,130**	**1,655**	**1,655**	**1,655**	**1,278**	**1,278**	**1,278**	**1,278**	**1,278**	
4	Owned Gas Steam	310	310	310	310	310	310	310	-	-	-	
5	Owned Gas Combined Cycle	1,855	1,941	1,968	1,968	1,968	1,968	1,968	1,968	1,968	1,968	
6	Purchased Gas Combined Cycle	370	302	170	51	51	-	-	-	-	-	
7	Owned Gas Combustion Turbine	805	1,067	1,067	1,067	1,067	1,067	896	896	896	896	
8	Purchased Gas Combustion Turbine	1,013	758	758	758	758	733	458	238	238	238	
9	**Total Gas-Fired Generation**	**4,352**	**4,378**	**4,273**	**4,155**	**4,155**	**4,078**	**3,632**	**3,102**	**3,102**	**3,102**	
10	Owned Storage	162	243	276	276	276	276	276	276	276	276	
11	Purchased Storage	-	-	199	199	199	199	199	199	199	199	
12	Purchased Biomass	3	3	3	-	-	-	-	-	-	-	
13	Owned Hydro	14	14	14	14	14	14	14	13	13	13	
14	Purchased Hydro	18	18	18	18	17	17	9	-	-	-	
15	Owned Solar	0.9	0.9	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	
16	Purchased Solar	202	363	673	669	666	663	659	653	650	647	
17	Purchased BTM Solar	172	195	119	119	125	130	136	144	153	164	
18	Purchased Community Solar	71	111	102	103	121	138	155	171	186	201	
19	Owned Wind	131	131	147	147	147	147	147	147	147	147	
20	Purchased Wind	360	360	402	402	402	394	384	316	316	313	
21	**Total Renewable/Other Generation**	**1,134**	**1,439**	**1,953**	**1,948**	**1,967**	**1,979**	**1,980**	**1,920**	**1,942**	**1,961**	
22	**TOTAL ACCREDITED CAPACITY**	**7,616**	**7,947**	**7,881**	**7,758**	**7,777**	**7,335**	**6,891**	**6,300**	**6,322**	**6,342**	*A*
23	Native Load Forecast - Winter2020	6,856	6,973	6,951	6,978	7,031	6,906	6,986	7,063	7,130	7,219	
24	Demand Response	(527)	(527)	(561)	(561)	(561)	(586)	(586)	(586)	(586)	(605)	
25	**FIRM OBLIGATION LOAD**	**6,329**	**6,446**	**6,390**	**6,417**	**6,470**	**6,320**	**6,400**	**6,477**	**6,544**	**6,614**	*B*
26	Target Planning Reserve Margin	1,139	1,160	1,233	1,232	1,242	1,207	1,152	1,166	1,178	1,191	
27	IREA & HCEA Backup Reserves	45	45	48	48	48	11	11	11	11	11	
28	**TOTAL PLANNING RESERVE MARGIN TARGET**	**1,184**	**1,205**	**1,281**	**1,280**	**1,290**	**1,219**	**1,163**	**1,177**	**1,189**	**1,201**	*C*
29	Actual Reserve Margin	1,287	1,501	1,492	1,341	1,307	1,016	491	(177)	(222)	(272)	*A - B*
30	**CAPACITY POSITION: LONG/(SHORT)**	**102**	**296**	**210**	**61**	**17**	**(203)**	**(672)**	**(1,354)**	**(1,411)**	**(1,474)**	*A - B - C*

	Announced Early Coal Retirements	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
31	Craig 2									(40)	(40)
32	Hayden 1									(135)	(135)
33	Hayden 2								(98)	(98)	(98)
34	**PREFERRED PLAN CAPACITY POSITION: LONG/(SHORT)**	**102**	**296**	**210**	**61**	**17**	**(203)**	**(672)**	**(1,452)**	**(1,684)**	**(1,747)**

The load and resource balance reflects the capacity needs associated with the Company's coal action plan as part of the preferred clean energy plan. The Company's preferred CEP includes the early retirements for Craig 2, Hayden 1, and Hayden 2 and the capacities for those respective facilities have been included in the need demonstrated above. However, the preferred CEP retains the same level of generation capacity for Pawnee (505 MW) and Comanche 3 (500 MW PSCo share) through 2030. Consistent with prior practice, the Company has also projected continued annual acquisitions of Retail Distributed Generation ("DG") throughout the RAP. Public Service will update these estimates in accordance with the Commission decisions when determining the resource needs to be filled through the Phase II acquisition process. Also embedded within the existing and planned generation values in Table 2.12-1 are the retirements of Comanche Units 1 and 2 as well as the Colorado Energy Plan

Portfolio resource additions[35] approved by the Commission (Proceeding No. 16A-0396E) and the 2016 ERP Amendment (Proceeding No. 19A-0530E).

Uncertainty in Phase II Resource/Capacity Need Assessment

Inherent in any forecast of resource need is the uncertainty associated with the Company's forecast of customer demand for electric service. That forecast is tied to various factors such as the local economic conditions of the state. In particular for this 2021 ERP, the level of beneficial electrification that is assumed within the RAP can have a material effect on the level of capacity needs. See Section 2.2 for further discussion.

[35] The capacity needs projected in Table 2.13-1 are calculated assuming the 72 MW Hartsel solar facility (34 MW ELCC) approved as part of the Colorado Energy Plan Portfolio is successfully brought on-line by December 31, 2022. At the time of this filing, Park County Colorado has, however, denied granting the needed permits for the project to proceed to construction. The Company will continue to monitor this situation and if needed, remove the project MW's from the Phase II L&R calculation of capacity needs.

2.13 PHASE I PLAN DEVELOPMENT AND MODELING DETAILS

EnCompass Model Description

In 2019, Public Service selected a new software package to replace Strategist and address the expressed need for more detailed modeling capabilities in the complex and evolving resource planning environment. Following an extensive evaluation process, Public Service selected "EnCompass," a software package produced by Anchor Power Solutions as its preferred replacement of Strategist.

Public Service selected the EnCompass model in part because the Company believes this option meets the expectations that have been expressed by the Commission and stakeholders regarding modeling functionality and transparency. For example, this new modeling software provides enhanced functionality by implementing a state-of-the-art solver algorithm that enables the ability to find optimal power supply portfolios among the highly complex processes we now regularly face in resource planning, such as managing over 400 bids received in the recent 2017 All-Source Solicitation, as well as increasing levels of renewables and storage alternatives. EnCompass allows modeling on an hourly chronological basis thereby providing increased resolution to accurately model power supply system operations with increasing levels of intermittent generation storage systems, and ancillary service requirements. The EnCompass tool is also able to perform utility capital accounting functions to translate power system investments into utility revenue requirements.

In addition to its enhanced functionality, the EnCompass software tool also meets the need for improved transparency and accessibility by other parties. For example, the data structure is easy to understand and manage and all inputs and outputs are shareable and readable in non-proprietary Excel spreadsheet format.

A more detailed description of the model, which is a document provided by the vendor, Anchor Power Solutions, is provided as Appendix G.

ERP and CEP Development

Analysis Framework

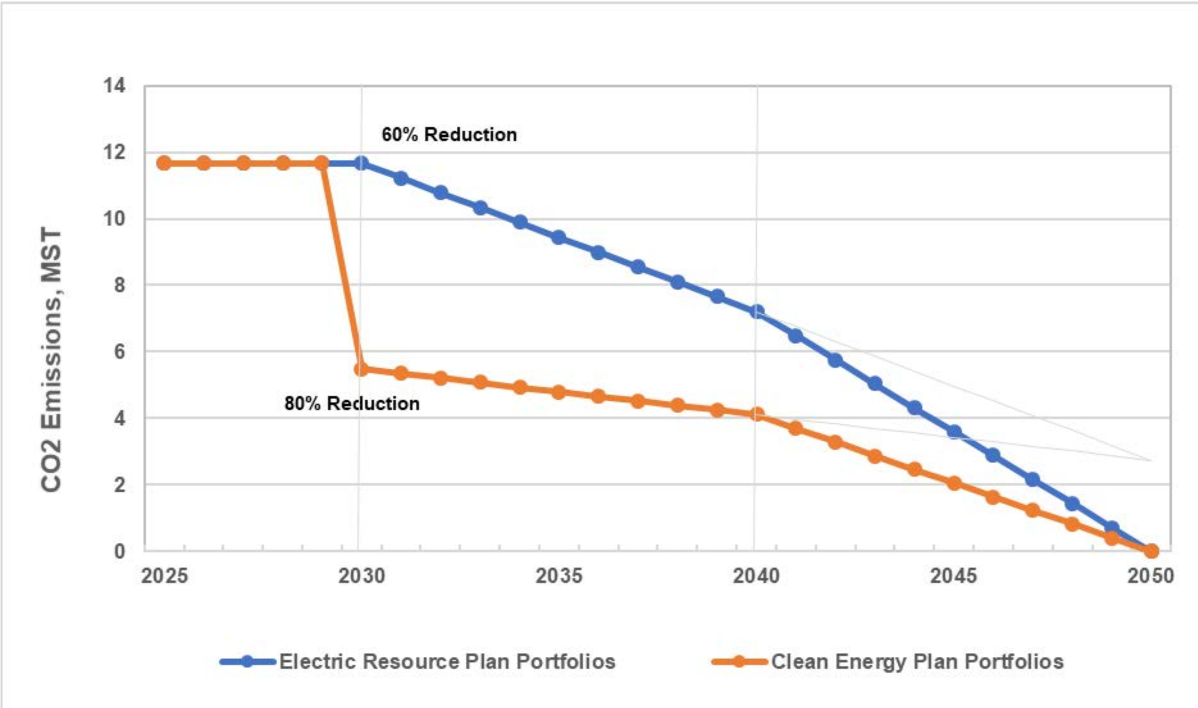
This Section describes the process by which the Company developed a suite of indicative resource portfolios that meet the projected resource needs of the Company for years 2021-2030 and the estimated costs of those portfolios over a 2021-2055 planning period. Portfolios were developed to meet two distinct resource needs: (1) ERP needs associated with meeting the Company's planning reserve margin target, reliability requirements, and other compliance requirements but without the requirement to achieve 80 percent carbon emissions reduction by 2030; and (2) CEP needs associated with meeting the same requirements as Electric Resource Plan portfolios plus achieving 80 percent carbon emissions reduction by 2030. Indicative portfolios were also developed under two different assumptions for the cost of carbon (CO_2) emissions, including: (1) the social cost of carbon ("SCC") as defined in SB 19-236; and (2) no cost of CO_2 ("$0/ton") as an alternative cost of CO_2 as described in SB 19-236.

Carbon Dioxide Emission Caps

Both ERP portfolios and CEP portfolios were required within the modeling to meet annual CO_2 emission caps on a trajectory to 100% reduction by 2050; however, their trajectory to 100% reduction by 2050 was different because CEP portfolios must meet the immediate requirement of 80% CO_2 reduction by 2030. As Figure 2.13-1 on the following page demonstrates, both ERP and CEP portfolios maintain the 60% CO_2 emission reduction achieved by the Company's Colorado Energy Plan which was approved in the 2016 ERP. ERP portfolios maintain this 60% reduction through 2030 and then have a trajectory of CO_2 emission caps from 2031-2050 which steadily require CO_2 reductions until reaching 100% achievement in 2050. CEP portfolios also must maintain the 60% reduction achieved through the Colorado Energy Plan through 2029, achieve the 80% requirement by 2030, and then must meet continued progress toward 100% achievement by 2050.

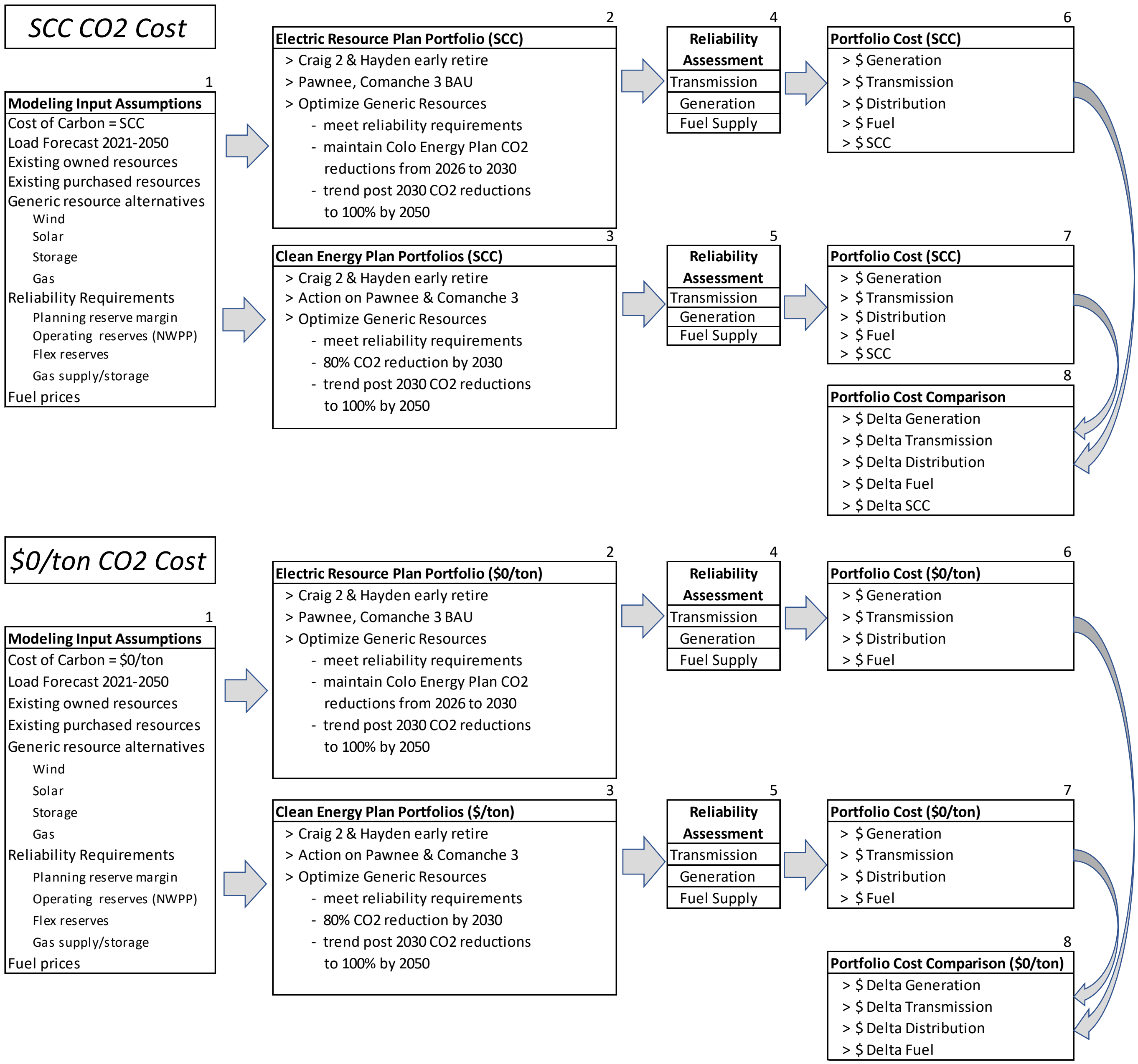
In application, continuous progress was set up as a linear reduction on a path to 90 percent reduction by 2050 for the period of 2030-2040. Then, starting in 2041, all of the scenarios were required to accelerate the trajectory of CO_2 reductions to reach zero tons of carbon by 2050. The ERP portfolios are not required to meet 80% reduction until 2042. During preliminary modeling, it was observed that the various stages of analysis, progressing from capacity expansion to production costing and detailed hourly commitment, resulted in increasing levels of carbon emissions for the same plan. Thus, lower caps were input into the modeling of capacity expansion and production costing to ensure plans were selected that would meet the true caps under real-time operations.

Figure 2.13-1 ERP and CEP CO_2 Emission Caps



Indicative ERP and CEP portfolios were developed using the EnCompass computer model. The Company proposes to use this same general framework for developing ERP and CEP portfolios in the Phase II process. Figure 2.13-2 on the following page provides a high-level illustration of the Company's analysis framework for creating these portfolios under both a SCC assumption and \$0/ton assumption. Boxes 1 through 8 of Figure 2.13-2 are described in more detail following the figure.

Figure 2.13-2 ERP and CEP Analysis Framework



Modeling Input Assumptions (1)

The base model was developed and populated with all the assumptions needed to fully represent the existing Public Service system and extend forecasts of required variables (i.e., load, fuel prices, etc.) through the modeling period. For Phase I, costs and performance characteristics of generic resources were added; for Phase II the individual bid costs and other bid characteristics, including location, will be utilized.

ERP Portfolios (2)

The ERP portfolios are optimized with both SCC and $0/ton CO_2 emission costs to meet the needs and requirements of the Public Service system absent the SB 19-236 requirement to achieve 80% CO_2 reduction by 2030. These portfolios maintain at least 60% CO_2 reduction through 2030 and then continued progress to 100% by 2050. These portfolios clearly distinguish the set of resources necessary to meet customer needs without the additional requirement of 80% CO_2 reduction by 2030. These portfolios will be used in measuring the additional costs or savings of each CEP portfolio.

CEP Portfolios (3)

The CEP portfolios meet the same customer needs as required by ERP portfolios with the added requirement of 80% CO_2 reduction by 2030 and then continued progress to 100% by 2050. These CO_2 reductions are accomplished by optimizing a set of generic resources around different combinations of coal actions as discussed in more detail below.

Reliability Assessment (4 & 5)

Each optimized portfolio of resources developed within the EnCompass model was reviewed to assess the expected reliability of the resulting Public Service system from three perspectives:

- *Transmission reliability*: assess the need for additional transmission upgrades to reliably deliver the output of the existing resources and new resources within each portfolio to load. This assessment was performed from both a real-time transmission operation perspective and a longer-term transmission planning perspective. To the extent additional transmission facilities were deemed necessary, the estimated cost of those facilities was included in the overall cost of the portfolio.

- *Generation reliability:* assess whether each portfolio contained sufficient levels and types of generation resources to reliably maintain the balance between load and generation. This included a review to assess whether the portfolio of resources could be expected to meet various reliability requirements, including but not limited to operating reserve (e.g., spin, nonspin, regulating), planning reserve margin, and flex reserve requirements. To the extent this review identified the need to make modifications as to how reliability requirements were being modeled or how resources being modeled were contributing to those reliability requirements, such changes were made within EnCompass.

- *Fuel supply reliability:* assess whether each portfolio contained sufficient firm fuel supply, natural gas storage, and gas storage withdrawal capability to reliably meet the projected peak gas demand requirements and hourly swings across the generation fleet. To the extent additional gas storage and withdrawal capability were identified, the estimated cost of those facilities was included in the overall cost of the portfolio.

Portfolio Costs (6 & 7)

Estimates of the total annual revenue requirements for each portfolio were developed for all years of the 2021-2055 planning period.[36] These total annual revenue requirements reflect the annual revenue the Company would collect from its electric customers (both retail and wholesale) to cover operating expenses and the Company's authorized rate of return associated with its existing electric generation, transmission and distribution system, as well as changes to the existing system, including but not limited to: additions and retirements/expirations within both the Company's owned and purchased generating fleet; the cost of fuel burned within that fleet; the cost of CO_2 emitted from that fleet; and the cost of additional transmission and distribution facilities necessary to deliver the output of the generation fleet to customers. Annual revenue requirements in nominal dollars were discounted at the Company's weighted average cost of capital ("WACC") as discussed in Section 2.14 below. For the expansion plans developed using the SCC, two dispatches of the portfolio were completed and costed: one including the SCC in the dispatch decision making process and one with no cost of carbon in the dispatch decision. The practical effect of including SCC in the dispatch decision is EnCompass will dispatch coal-fired resources last in the role of a peaking resource. In general, absent any future regulatory action, the Company generally considers the dispatch without the SCC in the dispatch decision as more reflective of current expectations and more realistic in modeling the real-life commit and dispatch decisions made by system operators faced with uncertainty in renewable output, generator outages, and the relatively long-lead time required by coal units to respond to variances in these real-life reliability challenges.

[36] As discussed elsewhere, the model was run through 2050, and the 2050 costs and load were repeated without inflation or growth to cover through 2055.

Portfolio Cost Comparison (8)

Estimates of the total annual revenue requirements for each CEP portfolio were compared with those of the ERP portfolio for all years of the 2021-2055 planning period. The differences in annual revenue requirements (both increases and decreases) between each CEP portfolio and the ERP portfolio were used to estimate the customer cost impacts of the different CEP portfolios over the planning period.

Coal Actions Considered

As of the time of this 2021 ERP & CEP filing, Public Service has a total of seven coal-fired units operating on its system.

Table 2.13-1 Public Service Coal-Fired Generating Units

Unit	Total (MW)	Public Service ownership (MW)	Retirement Date (EOY)	Location
Craig 2	410	40	2028	Moffat County, CO
Hayden 1	179	135	2028	Routt County, CO
Hayden 2	262	98	2027	Routt County, CO
Comanche 1	325	325	2022	Pueblo County, CO
Comanche 2	335	335	2025	Pueblo County, CO
Comanche 3	750	500	2069	Pueblo County, CO
Pawnee	505	505	2041	Morgan County, CO

Craig 2: In January 2020, Tri-State announced the closure of the Craig generation station located in NW Colorado by 2030. Public Service owns 10% of Craig 2. The joint owners of the Craig station agreed to early retire Craig 2 EOY 2028. As a result, all ERP and CEP portfolios include Craig 2 retiring EOY 2028.

Hayden 1 & 2: Public Service jointly owns the Hayden Station with PacifiCorp and Salt River Project. The joint owners of Hayden reached a consensus that Hayden 1 & 2 be early retired EOY 2028 and EOY 2027 respectively. As a result, all ERP and CEP portfolios include Hayden 1 & 2 retiring EOY 2028 and 2027 respectively.

Comanche 1 & 2: In Decision No. C18-0761 the Commission approved the Colorado Energy Plan which includes early retirement of Comanche 1 EOY 2022 and Comanche 2 EOY 2025. As a result, all ERP and CEP portfolios include Comanche 1 & 2 retiring EOY 2022 and 2025 respectively.

Comanche 3: In developing ERP and CEP portfolios, a range of actions were evaluated for the Comanche 3 unit including:

- Early retirement

- Conversion to burn natural gas
- Continued operation on coal at reduced output

Pawnee: In developing ERP and CEP portfolios, a range of actions were evaluated for the Pawnee unit including:

- Early retirement
- Conversion to burn natural gas

Combinations of Coal Actions Evaluated

As described above, all ERP and CEP portfolios evaluated and presented by the Company include early retirement of Craig 2, Hayden 1 & 2, and Comanche 1 & 2. With that, the evaluation of coal actions focused on the two remaining coal units, Pawnee and Comanche 3. The Company evaluated a variety of different combinations of paired actions associated with Pawnee and Comanche 3 as illustrated in Figure 2.13-3. The business as usual ("BAU") retirement date for Pawnee is 2041 and the BAU retirement date for Comanche 3 is 2069.

Figure 2.13-3 Pawnee and Comanche 3 Actions Considered

	Pawnee				Comanche 3				
Paired Action	Early Retire EOY 2028	Convert to Gas EOY 2027	Convert to Gas EOY 2024	BAU	Early Retire EOY 2029	Early Retire EOY 2039	Convert to Gas EOY 2027	Early Retire EOY 2039, Reduced Operations starting 2030	BAU
1				X					X
2	X				X				
3	X							X	
4		X					X		
5		X			X				
6		X				X			
7		X						X	
8			X					X	

Optimizing ERP and CEP Portfolios

A series of eight portfolios were developed around the common assumption of Craig 2, Hayden 1 & 2, and Comanche 1 & 2 early retirements coupled with the combinations of coal actions to Pawnee and Comanche 3 in Figure 2.13-3 above. Each separate portfolio was developed within the EnCompass computer model by hardcoding the separate combinations of early retirements and coal actions into the model and then running the model to optimize the additional resources that would be needed to meet the reliability requirements of the system and in the case of CEP portfolios, the requirement to reduce CO_2 emissions 80% by 2030.

<u>EnCompass Modeling Steps</u>: Portfolios were developed within the EnCompass model using a multi-step process.

Step 1 – Optimized Portfolios:

The first step optimized the generic resource additions needed to meet reliability and the modeled CO_2 emission caps from 2021-2050. These optimized portfolio runs were performed using two typical days per month. One of these days is a representative on-peak weekday, and the other is a representative off-peak weekend day. Step 1 optimized portfolios were completed with both SCC and $0/ton costs for CO_2 emissions included in the variable energy cost of the portfolios in addition to the CO_2 emission caps.

Step 2 – 8760-Dispatch:

The second step involved performing 8760-hourly dispatch ("8760-dispatch") for each year of each optimized portfolio from 2021-2050. These 8760-dispatch runs were used to determine the production costs and dispatch metrics of each portfolio, and the results of these 8760-dispatch runs are used to produce all data shown in this filing relating to the model output (i.e., portfolio costs, CO_2 emissions, energy mix, etc.). Step 2 8760-dispatch of optimized portfolios was completed with both SCC and $0/ton costs for CO_2 emissions included in the variable energy cost of the portfolios in addition to the CO_2 emission caps.

Step 2 runs were completed using a full chronological 8760 hour-per-year dispatch and included all ancillary service requirements and economic commitment and dispatch of all resources, including storage charge and discharge. For these runs, the EnCompass "partial commitment" setting was used to balance model runtime while still providing accurate annualized production cost information. Several scenarios were more fully explored at an hourly level using the "Full Commitment" setting for selected years to ensure reliability metrics were being met on an hourly basis and to provide a comparison of results between using the full or simplified commitment logic. The complexity of the PSCo system and modeling structure precluded using the full commitment logic for the entire modeling period for all scenarios – each year completed typically takes over 24 hours to complete. However, for Phase II modeling, the Company intends to revisit using the full commitment logic.

<u>Application of CO_2 Costs</u>: As illustrated in Figure 2.13-2 above, Step 1 ERP and CEP portfolios were optimized for two different assumptions for the cost of CO_2 emitted within a portfolio: (1) the SCC, and (2) $0/ton. The annual $/ton rate used to represent the SCC is discussed in Section 2.14.

For the SCC ERP and CEP optimized portfolios, the Step 1 portfolios were developed inclusive of pricing each ton of CO_2 emitted at the $/ton of SCC. The Step 1 portfolios were then dispatched two ways in separate Step 2 runs: one included the SCC in the dispatch process, and the other was dispatched without an explicit CO_2 cost. In the Step 2 with $0/ton CO_2 cost, the SCC was not included as an actual cost recovered from customers through the Company's revenue requirements or in the dispatch decision making process. Both views were provided to ensure full representation of the portfolios, as well as to provide a comparison of the effects of including SCC in the dispatch costing.

The $0/ton ERP and CEP optimized portfolios did not have a CO_2 cost included in either Step 1 or Step 2. Comparison of the plans produced under this assumption to the SCC portfolios, fully informs the impact of planning with or without inclusion of the SCC.

Asset Recovery: In cases where generation resources were modeled as being early retired or converted to burn gas, the recovery of any undepreciated plant balances were represented by the assumption that the Company would continue to depreciate the asset to the current retirement date of the asset up to the date that the early retirement or gas conversion action occurred, after which any remaining plant balance would be recovered over the 10-year period immediately following the early retirement year. This asset recovery approach is referred to herein as a regulated asset recovery approach. However, for the preferred plan (Portfolio SCC 7), the Company included a securitization approach for the remaining balance of Comanche 3 in 2040.

Generation Ownership: Consistent with the provisions of SB 19-236 all ERP and CEP portfolios were modeled in Phase I with an assumption that 50% of all new generation resources included in portfolios in years 2021-2030 of the planning period are Company-owned resources.

Fuel Supply: All ERP and CEP portfolios were modeled in Phase I with firm fuel supply and incremental gas storage needs in accordance with the studies performed by the Company and discussed in Section 2.18.

Transmission: The costs associated with the proposed Pathway Project were included in all portfolios. The expansion plans were initially optimized using incremental transmission cost "adders" for each generic resource, but these costs were removed from the first 5,000 MW of incremental generic renewable resources in each plan in the PVRR calculations under the assumption that the proposed transmission projects would supply the needed transmission infrastructure for these resources.

Community Assistance Plans and Work Force Transition: Community Assistance Plan and Workforce Transition Plan cost estimates were included within the modeling of ERP and CEP portfolios for all portfolios which included accelerated retirements. In addition, all ERP and CEP portfolios included Workforce Transition Plans for all coal units for all retirement dates modeled including BAU retirement dates. As discussed in the testimony of Company witness Jon Landrum, the costs in the model are placeholders as of the time the models were being developed. Company witnesses Hollie Velasquez Horvath and Holly Stanton further discuss the Company's proposal regarding Community Assistance Plans and Workforce Transition Plans.

SCC Optimized Portfolios and $0/ton 8760-dispatch Analysis Results

Presented in Table 2.13-2 are key attributes of 8 portfolios developed within the EnCompass model as described earlier, an Electric Resource Plan portfolio and seven Clean Energy Plan portfolios. The ERP portfolio is represented as SCC 1, and the Company's preferred CEP is represented by portfolio SCC 7. The seven Clean Energy Plan portfolios combine actions on Pawnee and Comanche 3 and generic resource additions around those coal actions to achieve CO_2 reductions. The SCC was used in the Step 1 development of these portfolios, specifically the amount and timing of generic resources added. The Present Value of Revenue Requirements ("PVRR") Utility Cost and rate impacts reported in Table 2.13-2 for each portfolio were developed from the 8760-dispatch of each portfolio over the 2021-2055 planning period with $0/ton CO_2 in the system dispatch decision. These SCC optimized portfolios use the SCC in Step 1 and use $0/ton in Step 2.

The colored heat mapping used for the portfolio analysis results provides a visual aid in assessing at a high level how the different portfolios compare or rank relative to one another for a particular portfolio characteristic (e.g., CO_2 reductions, PVRR Utility Cost, etc). The heat mapping uses a three-tiered color scale in which green represents the highest rank, yellow the middle rank, and red the lowest rank. There are two limitations to this heat mapping approach. One, it does not provide information as to whether the difference between a green, yellow or red ranking for a particular characteristic is a material difference. For example, a $10 million difference in the PVRR Utility Cost 2021-2055 between two portfolios could result in one portfolio ranking green and another yellow. Recognizing, however, that the total PVRR of portfolios is in the $40 billion range, a $10 million difference between portfolios in this instance would likely be viewed as immaterial. Nevertheless, the materiality of different color rankings for each portfolio characteristic is readily available within the numeric values provided. The other limitation is that the color rankings are relative to a comparison made between portfolios for the given set of assumptions, and those relative comparisons change when an assumption changes. For example, a $700 million PVRR Utility Cost increase might be ranked red for base assumptions but might be ranked green for High Gas Price assumptions when the relative comparisons are reset. Nonetheless, the relative rankings provide insight to how the portfolios rank for a given set of assumptions.

Table 2.13-2 ERP and CEP Portfolios Optimized Using Social Cost of Carbon (SCC *not* included in 8760-dispatch)

Preferred Plan (SCC 7)

SCC Optimized Portfolios $0/ton 8760-dispatch *50% ownership*								
Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
2030 CO2 % Reduction	-69%	-88%	-85%	-86%	-88%	-81%	-84%	-85%
CO2 Reduction Efficiency ($/ton)	-	$ 46	$ 48	$ 34	$ 36	$ 36	$ 38	$ 28
PVRR Utility Cost 2021-2055 ($M)	$ 38,814	$ 39,582	$ 39,429	$ 39,373	$ 39,450	$ 39,230	$ 39,306	$ 39,453
PVRR Utility Cost Delta vs. SCC 1								
2021-2030 ($M)	$ -	$ 271	$ 192	$ 284	$ 265	$ 177	$ 206	$ 302
2021-2040 ($M)	$ -	$ 951	$ 621	$ 622	$ 786	$ 387	$ 479	$ 591
2021-2055 ($M)	$ -	$ 768	$ 616	$ 560	$ 637	$ 417	$ 492	$ 639
Average Annual Rate Impact								
2024-2030 (%)	2.1%	3.1%	2.8%	2.8%	2.9%	2.4%	2.6%	2.5%
2024-2040 (%)	1.5%	1.5%	1.6%	1.5%	1.5%	1.6%	1.5%	1.6%
2024-2055 (%)	1.7%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
NPV CO2 2021-2055 ($M)	$ 8,625	$ 6,296	$ 6,719	$ 6,295	$ 6,234	$ 6,809	$ 6,646	$ 6,329
PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 47,439	$ 45,877	$ 46,148	$ 45,669	$ 45,684	$ 46,040	$ 45,951	$ 45,782
PVRR Utility Cost + NPV CO2 Delta vs. SCC 1								
2021-2030 ($M)	$ -	$ (124)	$ (77)	$ (271)	$ (226)	$ (153)	$ (158)	$ (370)
2021-2040 ($M)	$ -	$ (1,063)	$ (970)	$ (1,410)	$ (1,289)	$ (1,112)	$ (1,185)	$ (1,389)
2021-2055 ($M)	$ -	$ (1,561)	$ (1,290)	$ (1,770)	$ (1,755)	$ (1,399)	$ (1,487)	$ (1,657)
Infrastructure Investment Potential ($M)								
Generation 2021-2030 ($M)	$ 4,282	$ 6,223	$ 5,814	$ 5,519	$ 5,650	$ 4,847	$ 5,378	$ 5,360
Transmission 2021-2030 ($M)	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667
Phase II 2030 Resource Need (MW)	(1,747)	(2,752)	(2,252)	(1,747)	(2,247)	(1,747)	(1,747)	(1,747)
Resource Additions 2021-2030 (Nameplate MW)								
Wind	1,650	2,350	2,300	2,300	2,300	1,850	2,300	2,350
Utility-Scale Solar	1,150	1,550	1,550	1,500	1,550	1,250	1,550	1,550
Distributed Solar	1,158	1,158	1,158	1,158	1,158	1,158	1,158	1,158
Storage	400	450	400	450	400	400	400	400
Firm Dispatchable	1,276	2,352	1,960	1,568	1,764	1,505	1,276	1,233

__2030 CO_2 % Reduction:__ The percent CO_2 emission reduction in 2030 compared to year 2005 adjusted baseline level of 27.3 million short tons ("MST") for each portfolio.

__CO_2 Reduction Efficiency ($/ton):__ This measures the CO_2 reduction efficiency of a CEP portfolio relative to its respective ERP Portfolio with units of $/ton. It is the additional utility cost divided by the additional CO_2 removed of the CEP portfolio relative to its respective ERP portfolio, from 2021-2030 on a net present value basis. It does not consider incremental costs and associated carbon reductions for years 2031-2055.

PVRR Utility Cost 2021-2055 ($M): The net present value of the cost the utility will incur for implementing the portfolio from 2021-2055. It does not include the net present value of the total cost of carbon dioxide emissions of that portfolio.

PVRR Utility Cost Delta vs. SCC 1: The difference in the present value of the utility cost for implementing the portfolio compared to the ERP portfolio. The PVRR are presented for three different timeframes within the planning period: 2021-2030, 2021-2040, and 2021-2055. It does not include the difference in net present value of the total cost of carbon dioxide emissions of that portfolio.

Average Annual Rate Impact: The estimated average annual increase in total customer rates of each portfolio. The average customer rate impacts are presented in three timeframes: 2024-2030, 2024-2040, and 2024-2055. It does not include the calculation of the annual CO_2 emission costs, calculated by multiplying the annual CO_2 emissions by the SCC. 2024 was chosen as the start year to measure the rate impacts associated with clean energy actions of this ERP. The change from 2024 to 2025 is the first year of average annual rate impact.

NPV CO_2 2021-2055 ($M): The net present value of the total cost of carbon dioxide emissions of each portfolio from 2021-2055, calculated by multiplying the annual CO_2 emissions by the SCC.

PVRR Utility Cost + NPV CO_2 2021-2055 ($M): The net present value of the cost the utility will incur for implementing the portfolio plus the net present value of the total cost of carbon dioxide emissions of that portfolio.

PVRR Utility Cost + NPV CO_2 Delta vs. SCC 1: The difference in the net present value of the utility cost for implementing the portfolio plus the carbon emissions of the portfolio compared to the ERP portfolio. The PVRRs are presented for three different timeframes within the planning period: 2021-2030, 2021-2040, and 2021-2055.

Infrastructure Investment Potential ($M): The estimated capital investment potential associated with the generic generation resource additions and new transmission facilities for each portfolio between 2021 and 2030. The investments are total without any consideration of the owner of the assets.

Phase II Resource Need (MW): The forecasted capacity need of each portfolio by 2030. The capacity need varies by portfolio depending on the Pawnee and Comanche 3 actions. The capacity need will be updated prior to the Phase II process.

Resource Additions 2021-2030 (Nameplate MW):

- Wind: The nameplate amount of generic wind generation resources added in each portfolio.

- Utility-scale Solar: The nameplate amount of generic utility-scale solar generation resources added in each portfolio.
- Distributed Solar: The nameplate amount of generic distributed solar generation resources added in each portfolio. The amount is the same in all portfolios except for the Low Sales sensitivity discussed later in this section.
- Storage: The nameplate amount of generic 4-hour duration utility-scale storage resources added in each portfolio.
- Firm Dispatchable: The nameplate amount of generic firm-fueled dispatchable generation.

SCC Optimized Portfolios and SCC 8760-dispatch Analysis Results

Table 2.13-3 includes the same portfolios presented above in Table 2.13-2 with a different assumption for the 8760-dispatch. Unlike Table 2.13-2, Table 2.13-3 includes SCC in the 8760-dispatch decisions. These SCC optimized portfolios use the SCC in Step 1 and in Step 2. Since the portfolios in Table 2.13-3 have the same combinations of coal actions and generic resource additions as those in Table 2.13-2, the portfolio names are the same except for the addition of the suffix “A” to denote that they have an alternative 8760-dispatch and therefore a different fuel burn due to dispatch than those portfolios without the “A” suffix. Portfolio SCC 1A is the ERP portfolio, and portfolio SCC 7A is the Company’s preferred CEP with this alternative system dispatch representation. The practical effect of including SCC in the 8760-dispatch decision is EnCompass will dispatch coal-fired resources last in a peaking role. In general, absent any future regulatory action, the Company generally considers the 8760-dispatch without the SCC in the dispatch decision as more reflective of current expectations and more realistic in modeling the real-life system dispatch decisions faced by system operators.

Table 2.13-3 ERP and CEP Portfolios Optimized Using Social Cost of Carbon (SCC included in 8760-dispatch)

SCC Optimized Portfolios SCC 8760-dispatch *50% ownership*							*Preferred Plan*	
Portfolio	SCC 1A	SCC 2A	SCC 3A	SCC 4A	SCC 5A	SCC 6A	SCC 7A	SCC 8A
Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
2030 CO2 % Reduction	-76%	-90%	-88%	-88%	-89%	-82%	-88%	-88%
CO2 Reduction Efficiency ($/ton)	-	$ 59	$ 63	$ 41	$ 46	$ 49	$ 49	$ 37
PVRR Utility Cost 2021-2055 ($M)	$ 39,336	$ 39,969	$ 39,891	$ 39,752	$ 39,831	$ 39,600	$ 39,760	$ 39,882
PVRR Utility Cost Delta vs. SCC 1A								
2021-2030 ($M)	$ -	$ 243	$ 177	$ 244	$ 230	$ 151	$ 184	$ 257
2021-2040 ($M)	$ -	$ 828	$ 572	$ 491	$ 656	$ 246	$ 422	$ 510
2021-2055 ($M)	$ -	$ 633	$ 555	$ 416	$ 495	$ 264	$ 424	$ 546
Average Annual Rate Impact								
2024-2030 (%)	2.0%	2.9%	2.6%	2.6%	2.7%	2.3%	2.5%	2.4%
2024-2040 (%)	1.4%	1.5%	1.6%	1.4%	1.4%	1.5%	1.5%	1.5%
2024-2055 (%)	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
NPV CO2 2021-2055 ($M)	$ 6,987	$ 5,152	$ 5,357	$ 5,184	$ 5,128	$ 5,750	$ 5,328	$ 5,132
PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 46,323	$ 45,121	$ 45,249	$ 44,936	$ 44,959	$ 45,350	$ 45,088	$ 45,014
PVRR Utility Cost + NPV CO2 Delta vs. SCC 1A								
2021-2030 ($M)	$ -	$ (36)	$ (14)	$ (145)	$ (107)	$ (52)	$ (67)	$ (180)
2021-2040 ($M)	$ -	$ (718)	$ (768)	$ (1,041)	$ (914)	$ (701)	$ (947)	$ (1,055)
2021-2055 ($M)	$ -	$ (1,202)	$ (1,074)	$ (1,387)	$ (1,364)	$ (973)	$ (1,235)	$ (1,309)
Infrastructure Investment Potential ($M)								
Generation 2021-2030 ($M)	$ 4,282	$ 6,223	$ 5,814	$ 5,519	$ 5,650	$ 4,847	$ 5,378	$ 5,360
Transmission 2021-2030 ($M)	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667
Phase II 2030 Resource Need (MW)	(1,747)	(2,752)	(2,252)	(1,747)	(2,247)	(1,747)	(1,747)	(1,747)
Resource Additions 2021-2030 (Nameplate MW)								
Wind	1,650	2,350	2,300	2,300	2,300	1,850	2,300	2,350
Utility-Scale Solar	1,150	1,550	1,550	1,500	1,550	1,250	1,550	1,550
Distributed Solar	1,158	1,158	1,158	1,158	1,158	1,158	1,158	1,158
Storage	400	450	400	450	400	400	400	400
Firm Dispatchable	1,276	2,352	1,960	1,568	1,764	1,505	1,276	1,233

$0/ton Optimized Portfolios and $0/ton 8760-dispatch Analysis Results

Presented in Table 2.13-4 are key attributes of 8 portfolios developed within the EnCompass model assuming $0/ton cost of CO_2 emissions for both Step 1 and Step 2. By using annual CO_2 emission caps, EnCompass is able to solve for 80% CO_2 reduction without the optimization impact of SCC. $0/ton portfolios can be summarized as using $0/ton for Step 1 and for Step 2 and exclusively using CO_2 annual emission caps to build CEP portfolios. The combined coal actions are the same as the SCC optimized portfolios, but the amounts of generic renewable and storage resource additions are less and the generic firm dispatchable resource additions are more because the model does not include the savings of avoided CO_2 emissions using SCC in Step 1.

Table 2.13-4 ERP and CEP Portfolios Optimized Using $0/ton cost of CO_2 ($0/ton included in 8760-dispatch)

$0/ton Optimized Portfolios **$0/ton 8760-dispatch** *50% ownership*								
Portfolio	$0/ton 1	$0/ton 2	$0/ton 3	$0/ton 4	$0/ton 5	$0/ton 6	$0/ton 7	$0/ton 8
Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
2030 CO2 % Reduction	-63%	-81%	-81%	-81%	-81%	-81%	-81%	-81%
CO2 Reduction Efficiency ($/ton)	-	$ 39	$ 36	$ 24	$ 28	$ 29	$ 28	$ 23
PVRR Utility Cost 2021-2055 ($M)	$ 38,280	$ 38,875	$ 38,898	$ 38,692	$ 38,791	$ 38,913	$ 38,752	$ 38,898
PVRR Utility Cost Delta vs. $0/ton 1								
2021-2030 ($M)	$ -	$ 221	$ 153	$ 189	$ 193	$ 163	$ 160	$ 248
2021-2040 ($M)	$ -	$ 808	$ 647	$ 497	$ 649	$ 605	$ 510	$ 613
2021-2055 ($M)	$ -	$ 595	$ 617	$ 412	$ 511	$ 633	$ 472	$ 617
Average Annual Rate Impact								
2024-2030 (%)	1.8%	2.7%	2.3%	2.2%	2.5%	2.4%	2.1%	2.1%
2024-2040 (%)	1.5%	1.4%	1.5%	1.4%	1.4%	1.6%	1.4%	1.5%
2024-2055 (%)	1.7%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
NPV CO2 2021-2055 ($M)	$ 9,107	$ 7,051	$ 7,141	$ 6,924	$ 6,971	$ 7,027	$ 7,046	$ 6,758
PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 47,387	$ 45,926	$ 46,039	$ 45,616	$ 45,762	$ 45,940	$ 45,798	$ 45,656
PVRR Utility Cost + NPV CO2 Delta vs. $0/ton 1								
2021-2030 ($M)	$ -	$ (157)	$ (133)	$ (330)	$ (266)	$ (210)	$ (222)	$ (422)
2021-2040 ($M)	$ -	$ (974)	$ (1,044)	$ (1,421)	$ (1,212)	$ (1,182)	$ (1,277)	$ (1,462)
2021-2055 ($M)	$ -	$ (1,461)	$ (1,348)	$ (1,771)	$ (1,625)	$ (1,447)	$ (1,589)	$ (1,731)
Infrastructure Investment Potential ($M)								
Generation 2021-2030 ($M)	$ 2,528	$ 4,226	$ 3,942	$ 3,301	$ 3,540	$ 4,186	$ 3,495	$ 3,558
Transmission 2021-2030 ($M)	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667
Phase II 2030 Resource Need (MW)	(1,747)	(2,752)	(2,252)	(1,747)	(2,247)	(1,747)	(1,747)	(1,747)
Resource Additions 2021-2030 (Nameplate MW)								
Wind	1,000	1,000	1,150	1,000	1,000	1,700	1,150	1,150
Utility-Scale Solar	100	550	1,050	850	600	1,150	1,050	1,050
Distributed Solar	1,158	1,158	1,158	1,158	1,158	1,158	1,158	1,158
Storage	50	50	50	50	50	-	50	100
Firm Dispatchable	1,764	3,269	2,352	1,960	2,548	1,764	1,764	1,764

Portfolio Analysis Discussion

As indicated in Table 2.13-2, all CEP portfolios optimized with SCC exceed the 80% CO_2 reduction requirement by 1% to 8%, which is the equivalent of approximately 0.25 million short tons ("MST") to 2 MST of CO_2, in 2030. The ERP portfolio achieves 69% CO_2 reduction by adding 2,800 MW of renewables coupled with the retirements of the Craig 2 and Hayden 1 & 2 units. The CEP portfolios achieve the greater CO_2

reductions by combining the paired Pawnee and Comanche 3 actions with additional renewables from as little as 300 MW incremental compared to the ERP portfolio in SCC 6 to 1,100 MW incremental renewables in SCC 2 and SCC 8. The SCC optimized portfolios in general can be characterized by higher renewable additions, higher CO_2 reductions, and less dependence on firm dispatchable resources achieved in part through the more storage resource additions and higher renewable additions. The Company's Preferred CEP is represented by portfolio SCC 7 which adds 2,300 MW of wind, 1,550 MW utility-scale solar, 400 MW of utility-scale storage, and 1,276 MW of firm dispatchable generic resources and has a projected CO_2 reduction of 84% by 2030. While adding nearly the most incremental renewables of all the CEP portfolios, it adds no more firm dispatchable resources than the ERP portfolio. It accomplishes this by preserving the firm dispatchable capacity of Pawnee and Comanche 3 through 2030. The preferred CEP portfolio exceeds the CO_2 reduction requirement by 4%, or by over 1 MST. This makes the Preferred CEP within 2%, or approximately 0.5 MST, of all the CEP portfolios which do not early retire Pawnee or Comanche 3.

CEP portfolios SCC 6, SCC 7, and SCC 8 all convert Pawnee to a natural gas-fired unit and have the same retirement date of Comanche 3. They vary in the assumed conversion date of Pawnee to natural gas and the operation of Comanche 3 with varying outcomes on costs and CO_2 emissions. The Company's Preferred CEP, which converts Pawnee to gas EOY 2027 and retires Comanche 3 EOY 2039 with reduced operations starting 2030, does not achieve the highest CO_2 reductions nor does it have the least cost impact. However, SCC 6 which has the least cost impact only achieves 81% CO_2 reduction, and SCC 8 achieves slightly more CO_2 reduction but at the expense of a larger cost impact. Part of what differentiates these portfolios is the amount of generation supplied by coal. The less the coal generation across these plans the higher the CO_2 reductions and the greater the cost impacts. Of these 3 CEP portfolios, SCC 8 has the least coal generation, highest cost impact, and the highest CO_2 reductions, and SCC 6 has the most coal generation, least cost impact, and the least CO_2 reductions. SCC 7 strikes a balance between coal generation, cost impact, and CO_2 reductions as compared to SCC 6 and SCC 8.

The remaining CEP portfolios, SCC 2 through SCC 4, differ from SCC 7 by retiring either Pawnee or Comanche 3 by 2030 or converting both units to natural gas in the case of SCC 4. The CEP portfolios which retire either Pawnee or Comanche 3 require firm dispatchable resources in greater amounts than in the Company's Preferred CEP in order to replace the retired firm dispatchable capacity. SCC 3 portfolio has similar cost impact and CO_2 achievement through 2030 as SCC 7, but it has greater cost impact after 2030 than SCC 7. SCC 7 minimizes the requirement of new firm-fueled dispatchable resources which lowers its cost impact through 2030 and after.

The $0/ton Optimized Portfolios in general add fewer renewables and storage, more firm-dispatchable resources, and achieve less CO_2 reductions as compared to the SCC Optimized Portfolios. The ERP portfolio, $0/ton 1, adds 1,100 MW of renewables and 50 MW of storage and achieves 63% CO_2 reduction by 2030. This is near the minimum

CO_2 reduction for this portfolio since the emissions cap for this portfolio is 60% in 2030. All of the CEP portfolios add 1,550 MW to 2,850 MW more utility-scale renewables, or between 450 MW to 1,750 MW more than $0/ton 1. These additional renewables, plus the same coal actions as presented in the SCC Optimized Portfolios, achieve nearly identical 81% CO_2 reductions across all CEP portfolios. These similar CO_2 reductions are caused by the emission cap of 80%, which EnCompass used to find the required renewable additions to achieve the 80% reduction target. The SCC Optimized Portfolios on average add 1,700 MW more renewables and 400 MW more storage than the $0/ton Optimized Portfolios.

$0/ton 7 which has the same coal actions as SCC 7, but 1,650 MW less renewables and 350 MW less storage, has cost savings compared to other $0/ton CEP portfolios. This demonstrates that the Company's preferred coal actions for Pawnee and Comanche 3 have customer benefits across varying renewable and storage levels.

The CO_2 Reduction Efficiency presented in the above tables is a useful metric to compare the CEP portfolios, with lower $/ton values being better in that they indicate higher carbon reductions for each incremental dollar spent compared to its respective ERP portfolio. This metric captures the time value of costs and CO_2 reductions through 2030 on a net present value basis to compare the clean energy actions of the portfolios. The CO_2 Reduction Efficiency is the ratio of the delta utility cost to the delta carbon reduction of a CEP portfolio relative to its respective ERP portfolio on a net present value basis through 2030. Since its variables are dependent on the delta of a CEP portfolio relative to an ERP portfolio, the CO2 Reduction Efficiency of a CEP portfolio for a given set of assumptions is not comparable to the CO_2 Reduction Efficiency of a CEP portfolio for a different set of assumptions. ERP portfolios with different sets of assumptions may have significantly different costs and carbon reductions making any comparisons of the CO_2 Reduction Efficiency across assumptions not instructive comparisons.

In the SCC Optimized Portfolios, with the higher CO_2 reduction achievements, the portfolio which reduced coal generation the most through 2030, SCC 8, has the lowest CO_2 Reduction Efficiency at $28/ton. This plan achieves the most CO_2 reductions through 2030 by converting Pawnee to natural gas EOY 2024, which is the earliest coal action across all portfolios. As a result of using the present value of CO_2 reductions, SCC 8 shows a higher reduction efficiency than other CEP portfolios even though some of those other portfolios result in overall higher carbon emission reductions by 2030. Most of the SCC CEP portfolios are in the $30/ton range with only a few in the $40/ton range caused by the early retirements of either or both of Pawnee and Comanche 3. This demonstrates that the retirements of Pawnee or Comanche 3 may not be the most cost-efficient CO_2 reduction actions available in the modeling.

The $0/ton CEP portfolios have CO_2 Reduction Efficiencies in the $20/ton range except for a few plans which retire either or both of Pawnee and Comanche 3. The $0/ton CEP portfolios have lower cost CO_2 Reduction Efficiencies than the SCC CEP portfolios because in general they do not achieve as high of CO_2 reductions as the SCC CEP portfolios. The higher renewable additions of the SCC CEP portfolios reflect a degree of diminishing return in achieving the higher CO_2 reductions.

The CEP portfolios in general save about $2.0 billion in net present value of CO_2 emissions as compared to the ERP portfolios as measured by the SCC. This is the CO_2 savings associated with achieving and in some portfolios exceeding the 80% CO_2 reduction target by 2030 and continued CO_2 savings through 2040 until the later year CO_2 emission caps that were modeled, begin to force both the ERP and CEP portfolios to achieve 100% CO_2 reduction by 2050.

The costs associated with the proposed Pathway Project were included in all ERP and CEP portfolios. The expansion plans were initially optimized using incremental transmission costs for each generic resource, but these costs were removed and replaced by the revenue requirements of the Pathway Project for the first 5,000 MW of incremental generic renewable resources in each portfolio under the assumption that the proposed Pathway Project would supply the needed transmission infrastructure for these resources.

Sensitivity Analysis Description

In addition to evaluation of ERP and CEP portfolios under base assumptions, ERP and CEP portfolios were further analyzed through sensitivity analyses that involved changing a single key input assumption and assessing how that change impacts either each ERP and CEP portfolio's cost (i.e., repricing sensitivity) or the cost and composition of resources in the portfolios (i.e., reoptimized sensitivity). The difference between the two types is whether the capacity expansion plan is re-optimized or not. Some sensitivities (such as change in fuel prices), do not require that a new optimized expansion plan be developed in order to assess the impact of the changed assumption. These types of sensitivities are referred to as repricing sensitivities. For certain sensitivities (such as load changes), it is necessary to create a new expansion plan. These types of sensitivities are referred to as reoptimized sensitivities. Regardless of the type, for simplicity, all of these alternative analyses are termed sensitivities. The primary purpose of these sensitivities is to test the robustness of the Company's selection of SCC 7 as our preferred plan under different futures.

Repricing sensitivities: In a repricing sensitivity analysis the cost to operate the optimized portfolio of generation resources over the planning period is assessed under a different future assumption for one key model input variable. In these analyses the model is not allowed to change the mix or timing of generic resources that were added under the Base Case optimization but is allowed to change how the generic and existing resources in the portfolio are dispatched to meet load. Repricing sensitivities were performed on portfolios under the following assumptions:

- High Gas Prices: Increase natural gas prices by using twice the annual year-over-year growth rate of the base gas price forecast

- Low Gas Prices: Reduce natural gas prices by using one-half the annual year-over-year growth rate of the base gas price forecast

High and Low Gas Price sensitivities were performed for all ERP and CEP portfolios for both SCC and $0/ton optimized portfolios.

Reoptimized sensitivities: In a reoptimized sensitivity analysis each ERP or CEP portfolio is reoptimized over the planning period under a different future assumption for one key model input variable. In a reoptimized sensitivity analysis the model is given the flexibility to select a different mix of generic resources from those which were selected in the optimization performed using base assumptions. Reoptimized sensitivities were performed on portfolios under the following assumptions:

- High Load: Increased electrification consistent with the Greenhouse Gas Emission Reduction Roadmap developed by State of Colorado agencies
- Low Sales: Higher adoption of distributed energy resources and slower growth in load not associated with electrification
- Sunk Transmission Upgrade Cost: Assumes transmission network upgrade costs are sunk. The costs of all generic resource additions do not include any costs for network transmission
- No New Gas Resources: Assumes no new gas-fired generation is added to the system
- Lower Hydrogen Costs: The base assumption of $20/mmBtu was lowered to $10/mmBtu for the period hydrogen becomes integrated into the system (2041-2050)
- Expanded Market Access: Increase MW import and export capacity within the modeling by doubling the base assumption for tie limit interchange with the two economy markets. No specific transmission-related costs for this expansion were included in the modeling.

High Load and Low Sales sensitivities were performed for all ERP and CEP portfolios for both SCC and $0/ton results. Sunk Transmission Upgrade Cost, No New Gas Resources, Lower Hydrogen Costs, and Expanded Market Access sensitivities were performed for SCC 1, 2, 4, and 7 for only the SCC results to reduce the modeling requirements for the Phase I filing.

SCC Optimized Portfolios Sensitivity Results

Table 2.13-5 ERP and CEP Portfolios Repriced Using High Gas Prices

SCC Optimized Portfolios
$0/ton 8760-dispatch
50% ownership

Preferred Plan (SCC 7)

	Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
High Gas Prices	**2030 CO2 % Reduction**	-69%	-88%	-85%	-86%	-88%	-81%	-84%	-84%
	CO2 Reduction Efficiency ($/ton)	-	$ 49	$ 50	$ 37	$ 39	$ 38	$ 40	$ 31
	PVRR Utility Cost 2021-2055 ($M)	$ 39,440	$ 40,326	$ 40,127	$ 40,180	$ 40,215	$ 39,944	$ 40,024	$ 40,178
	PVRR Utility Cost Delta vs. SCC 1								
	2021-2030 ($M)	$ -	$ 290	$ 202	$ 316	$ 290	$ 191	$ 222	$ 329
	2021-2040 ($M)	$ -	$ 1,057	$ 680	$ 778	$ 912	$ 463	$ 558	$ 678
	2021-2055 ($M)	$ -	$ 887	$ 687	$ 740	$ 775	$ 505	$ 584	$ 738
	Average Annual Rate Impact								
	2024-2030 (%)	2.2%	3.2%	2.9%	2.9%	3.0%	2.6%	2.7%	2.6%
	2024-2040 (%)	1.7%	1.7%	1.8%	1.7%	1.6%	1.8%	1.7%	1.7%
	2024-2055 (%)	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.6%
	NPV CO2 2021-2055 ($M)	$ 8,660	$ 6,319	$ 6,742	$ 6,315	$ 6,256	$ 6,828	$ 6,668	$ 6,352
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 48,099	$ 46,645	$ 46,869	$ 46,495	$ 46,471	$ 46,773	$ 46,691	$ 46,530
	PVRR Utility Cost + NPV CO2 Delta vs. SCC 1								
	2021-2030 ($M)	$ -	$ (109)	$ (69)	$ (244)	$ (206)	$ (144)	$ (146)	$ (347)
	2021-2040 ($M)	$ -	$ (968)	$ (922)	$ (1,268)	$ (1,175)	$ (1,052)	$ (1,118)	$ (1,313)
	2021-2055 ($M)	$ -	$ (1,454)	$ (1,230)	$ (1,604)	$ (1,628)	$ (1,327)	$ (1,408)	$ (1,570)
Change from Base Assumptions	**2030 CO2 % Reduction**	0%	0%	0%	0%	0%	0%	0%	0%
	CO2 Reduction Efficiency ($/ton)	-	$ 3	$ 2	$ 4	$ 3	$ 2	$ 3	$ 2
	PVRR Utility Cost 2021-2055 ($M)	$ 626	$ 744	$ 698	$ 806	$ 765	$ 714	$ 718	$ 725
	Average Annual Rate Impact								
	2024-2030 (%)	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%
	2024-2040 (%)	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%
	2024-2055 (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	NPV CO2 2021-2055 ($M)	$ 34	$ 23	$ 23	$ 20	$ 23	$ 19	$ 22	$ 23
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 661	$ 768	$ 721	$ 826	$ 787	$ 733	$ 740	$ 748

Table 2.13-6 ERP and CEP Portfolios Repriced Using Low Gas Prices

SCC Optimized Portfolios
$0/ton 8760-dispatch
50% ownership

Preferred Plan

		SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
	Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
Low Gas Prices	**2030 CO2 % Reduction**	-70%	-88%	-85%	-86%	-88%	-81%	-84%	-85%
	CO2 Reduction Efficiency ($/ton)	-	$ 44	$ 47	$ 31	$ 34	$ 34	$ 36	$ 27
	PVRR Utility Cost 2021-2055 ($M)	$ 38,351	$ 39,026	$ 38,912	$ 38,769	$ 38,878	$ 38,699	$ 38,772	$ 38,911
	PVRR Utility Cost Delta vs. SCC 1								
	2021-2030 ($M)	$ -	$ 256	$ 183	$ 256	$ 245	$ 165	$ 193	$ 278
	2021-2040 ($M)	$ -	$ 867	$ 574	$ 497	$ 685	$ 327	$ 416	$ 520
	2021-2055 ($M)	$ -	$ 675	$ 560	$ 417	$ 527	$ 348	$ 420	$ 559
	Average Annual Rate Impact								
	2024-2030 (%)	2.1%	3.0%	2.7%	2.6%	2.8%	2.3%	2.5%	2.4%
	2024-2040 (%)	1.4%	1.4%	1.5%	1.4%	1.4%	1.5%	1.4%	1.5%
	2024-2055 (%)	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
	NPV CO2 2021-2055 ($M)	$ 8,551	$ 6,263	$ 6,686	$ 6,269	$ 6,204	$ 6,783	$ 6,615	$ 6,304
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 46,902	$ 45,290	$ 45,597	$ 45,038	$ 45,082	$ 45,482	$ 45,387	$ 45,214
	PVRR Utility Cost + NPV CO2 Delta vs. SCC 1								
	2021-2030 ($M)	$ -	$ (131)	$ (77)	$ (286)	$ (235)	$ (154)	$ (161)	$ (379)
	2021-2040 ($M)	$ -	$ (1,107)	$ (977)	$ (1,490)	$ (1,348)	$ (1,126)	$ (1,206)	$ (1,412)
	2021-2055 ($M)	$ -	$ (1,613)	$ (1,305)	$ (1,864)	$ (1,820)	$ (1,420)	$ (1,516)	$ (1,688)
Change from Base Assumptions	**2030 CO2 % Reduction**	0%	0%	0%	0%	0%	0%	0%	0%
	CO2 Reduction Efficiency ($/ton)	$ -	$ (2)	$ (1)	$ (3)	$ (2)	$ (1)	$ (1)	$ (2)
	PVRR Utility Cost 2021-2055 ($M)	$ (462)	$ (555)	$ (518)	$ (604)	$ (572)	$ (531)	$ (534)	$ (542)
	Average Annual Rate Impact								
	2024-2030 (%)	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%
	2024-2040 (%)	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%
	2024-2055 (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	NPV CO2 2021-2055 ($M)	$ (74)	$ (32)	$ (33)	$ (26)	$ (30)	$ (26)	$ (30)	$ (25)
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ (536)	$ (588)	$ (551)	$ (631)	$ (602)	$ (557)	$ (565)	$ (567)

Table 2.13-7 ERP and CEP Portfolios Reoptimized with High Load

SCC Optimized Portfolios
$0/ton 8760-dispatch
50% ownership

Preferred Plan

	Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
High Load	**2030 CO2 % Reduction**	-69%	-87%	-84%	-85%	-87%	-81%	-84%	-83%
	CO2 Reduction Efficiency ($/ton)	-	$ 40	$ 42	$ 21	$ 33	$ 20	$ 26	$ 20
	PVRR Utility Cost 2021-2055 ($M)	$ 43,690	$ 44,380	$ 44,320	$ 44,068	$ 44,328	$ 44,159	$ 44,182	$ 44,189
	PVRR Utility Cost Delta vs. SCC 1								
	2021-2030 ($M)	$ -	$ 224	$ 153	$ 161	$ 233	$ 96	$ 138	$ 202
	2021-2040 ($M)	$ -	$ 846	$ 604	$ 395	$ 754	$ 426	$ 479	$ 422
	2021-2055 ($M)	$ -	$ 690	$ 630	$ 378	$ 638	$ 470	$ 492	$ 500
	Average Annual Rate Impact								
	2024-2030 (%)	1.7%	2.5%	2.1%	2.0%	2.3%	1.9%	2.0%	1.9%
	2024-2040 (%)	0.8%	0.9%	1.0%	0.9%	0.8%	1.0%	0.9%	0.9%
	2024-2055 (%)	1.4%	1.3%	1.3%	1.4%	1.3%	1.3%	1.4%	1.3%
	NPV CO2 2021-2055 ($M)	$ 8,783	$ 6,668	$ 7,020	$ 6,716	$ 6,593	$ 7,004	$ 6,919	$ 6,659
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 52,472	$ 51,048	$ 51,340	$ 50,784	$ 50,921	$ 51,163	$ 51,101	$ 50,848
	PVRR Utility Cost + NPV CO2 Delta vs. SCC 1								
	2021-2030 ($M)	$ -	$ (150)	$ (95)	$ (357)	$ (242)	$ (223)	$ (214)	$ (433)
	2021-2040 ($M)	$ -	$ (1,003)	$ (892)	$ (1,424)	$ (1,172)	$ (1,074)	$ (1,119)	$ (1,437)
	2021-2055 ($M)	$ -	$ (1,425)	$ (1,132)	$ (1,688)	$ (1,551)	$ (1,309)	$ (1,372)	$ (1,624)
	Infrastructure Investment Potential ($M)								
	Generation 2021-2030 ($M)	$ 5,508	$ 7,251	$ 6,703	$ 6,049	$ 6,749	$ 5,688	$ 6,318	$ 6,101
	Transmission 2021-2030 ($M)	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667
	Phase II 2030 Resource Need (MW)	(2,009)	(3,014)	(2,514)	(2,009)	(2,509)	(2,009)	(2,009)	(2,009)
	Resource Additions 2021-2030 (Nameplate MW)								
	Wind	2,350	2,850	2,850	2,750	2,900	2,600	2,900	2,750
	Utility-Scale Solar	1,350	1,700	1,750	1,650	1,750	1,500	1,750	1,700
	Distributed Solar	1,158	1,158	1,158	1,158	1,158	1,158	1,158	1,158
	Storage	450	500	500	500	500	450	500	500
	Firm Dispatchable	1,625	2,389	1,960	1,372	1,960	1,372	1,372	1,372
Change from Base Assumptions	**2030 CO2 % Reduction**	0%	1%	1%	1%	1%	0%	1%	1%
	CO2 Reduction Efficiency ($/ton)	-	$ (6)	$ (6)	$ (13)	$ (3)	$ (16)	$ (12)	$ (8)
	PVRR Utility Cost 2021-2055 ($M)	$ 4,876	$ 4,798	$ 4,890	$ 4,695	$ 4,878	$ 4,929	$ 4,876	$ 4,737
	Average Annual Rate Impact								
	2024-2030 (%)	-0.4%	-0.6%	-0.6%	-0.8%	-0.5%	-0.5%	-0.6%	-0.6%
	2024-2040 (%)	-0.7%	-0.7%	-0.7%	-0.7%	-0.6%	-0.6%	-0.7%	-0.7%
	2024-2055 (%)	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%
	NPV CO2 2021-2055 ($M)	$ 157	$ 372	$ 301	$ 420	$ 360	$ 194	$ 273	$ 330
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 5,033	$ 5,170	$ 5,192	$ 5,115	$ 5,237	$ 5,123	$ 5,149	$ 5,067
	Infrastructure Investment Potential ($M)								
	Generation 2021-2030 ($M)	$ 1,227	$ 1,028	$ 889	$ 530	$ 1,099	$ 841	$ 939	$ 740
	Transmission 2021-2030 ($M)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Phase II 2030 Resource Need (MW)	(262)	(262)	(262)	(262)	(262)	(262)	(262)	(262)
	Resource Additions 2021-2030 (Nameplate MW)								
	Wind	700	500	550	450	600	750	600	400
	Utility-Scale Solar	200	150	200	150	200	250	200	150
	Distributed Solar	-	-	-	-	-	-	-	-
	Storage	50	50	100	50	100	50	100	100
	Firm Dispatchable	349	37	-	(196)	196	(133)	96	139

Table 2.13-8 ERP and CEP Portfolios Reoptimized with Low Sales

SCC Optimized Portfolios
$0/ton 8760-dispatch
50% ownership

Preferred Plan (SCC 7)

	Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
Low Sales	**2030 CO2 % Reduction**	-70%	-89%	-85%	-87%	-88%	-81%	-85%	-85%
	CO2 Reduction Efficiency ($/ton)	-	$ 45	$ 47	$ 28	$ 38	$ 25	$ 43	$ 33
	PVRR Utility Cost 2021-2055 ($M)	$ 38,991	$ 39,736	$ 39,610	$ 39,487	$ 39,645	$ 39,408	$ 39,490	$ 39,664
	PVRR Utility Cost Delta vs. SCC 1								
	2021-2030 ($M)	$ -	$ 267	$ 186	$ 230	$ 275	$ 118	$ 236	$ 341
	2021-2040 ($M)	$ -	$ 906	$ 599	$ 525	$ 787	$ 357	$ 491	$ 628
	2021-2055 ($M)	$ -	$ 746	$ 620	$ 496	$ 654	$ 418	$ 499	$ 673
	Average Annual Rate Impact								
	2024-2030 (%)	2.1%	3.1%	2.7%	2.6%	2.9%	2.4%	2.5%	2.5%
	2024-2040 (%)	1.5%	1.6%	1.7%	1.6%	1.5%	1.7%	1.6%	1.6%
	2024-2055 (%)	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
	NPV CO2 2021-2055 ($M)	$ 8,442	$ 6,159	$ 6,581	$ 6,178	$ 6,089	$ 6,712	$ 6,511	$ 6,203
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 47,432	$ 45,895	$ 46,191	$ 45,665	$ 45,734	$ 46,120	$ 46,001	$ 45,867
	PVRR Utility Cost + NPV CO2 Delta vs. SCC 1								
	2021-2030 ($M)	$ -	$ (127)	$ (81)	$ (316)	$ (206)	$ (192)	$ (126)	$ (320)
	2021-2040 ($M)	$ -	$ (1,056)	$ (940)	$ (1,434)	$ (1,244)	$ (1,052)	$ (1,118)	$ (1,290)
	2021-2055 ($M)	$ -	$ (1,537)	$ (1,241)	$ (1,768)	$ (1,698)	$ (1,312)	$ (1,431)	$ (1,566)
	Infrastructure Investment Potential ($M)								
	Generation 2021-2030 ($M)	$ 3,600	$ 5,529	$ 4,905	$ 4,453	$ 4,895	$ 3,955	$ 4,598	$ 4,650
	Transmission 2021-2030 ($M)	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667
	Phase II 2030 Resource Need (MW)	(1,436)	(2,441)	(1,941)	(1,436)	(1,936)	(1,436)	(1,436)	(1,436)
	Resource Additions 2021-2030 (Nameplate MW)								
	Wind	1,550	2,250	2,200	2,150	2,200	1,700	2,150	2,200
	Utility-Scale Solar	850	1,000	1,000	1,000	1,000	1,000	1,000	1,000
	Distributed Solar	1,556	1,556	1,556	1,556	1,556	1,556	1,556	1,556
	Storage	250	450	350	400	350	300	400	400
	Firm Dispatchable	1,176	2,156	1,568	980	1,568	1,176	1,176	1,176
Change from Base Assumptions	**2030 CO2 % Reduction**	-1%	-1%	0%	0%	0%	0%	0%	0%
	CO2 Reduction Efficiency ($/ton)	-	$ (1)	$ (1)	$ (6)	$ 2	$ (10)	$ 6	$ 4
	PVRR Utility Cost 2021-2055 ($M)	$ 177	$ 155	$ 181	$ 114	$ 195	$ 178	$ 184	$ 211
	Average Annual Rate Impact								
	2024-2030 (%)	0.0%	0.0%	-0.1%	-0.2%	0.0%	-0.1%	0.0%	0.0%
	2024-2040 (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	2024-2055 (%)	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
	NPV CO2 2021-2055 ($M)	$ (184)	$ (137)	$ (138)	$ (118)	$ (145)	$ (98)	$ (134)	$ (126)
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ (7)	$ 18	$ 43	$ (4)	$ 50	$ 80	$ 50	$ 85
	Infrastructure Investment Potential ($M)								
	Generation 2021-2030 ($M)	$ (682)	$ (694)	$ (909)	$ (1,066)	$ (755)	$ (892)	$ (780)	$ (710)
	Transmission 2021-2030 ($M)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Phase II 2030 Resource Need (MW)	311	311	311	311	311	311	311	311
	Resource Additions 2021-2030 (Nameplate MW)								
	Wind	(100)	(100)	(100)	(150)	(100)	(150)	(150)	(150)
	Utility-Scale Solar	(300)	(550)	(550)	(500)	(550)	(250)	(550)	(550)
	Distributed Solar	399	399	399	399	399	399	399	399
	Storage	(150)	-	(50)	(50)	(50)	(100)	-	-
	Firm Dispatchable	(100)	(196)	(392)	(588)	(196)	(329)	(100)	(57)

Table 2.13-9 ERP and CEP Portfolios Reoptimized with Sunk Transmission Cost

	SCC Optimized Portfolios $0/ton 8760-dispatch *50% ownership*							Preferred Plan	
	Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
Sunk Transmission Upgrade Cost	**2030 CO2 % Reduction**	-71%	-90%		-87%			-86%	
	CO2 Reduction Efficiency ($/ton)	-	$ 44		$ 23			$ 29	
	PVRR Utility Cost 2021-2055 ($M)	$ 37,375	$ 38,058		$ 37,740			$ 37,848	
	PVRR Utility Cost Delta vs. SCC 1								
	2021-2030 ($M)	$ -	$ 263		$ 181			$ 159	
	2021-2040 ($M)	$ -	$ 863		$ 392			$ 463	
	2021-2055 ($M)	$ -	$ 683		$ 365			$ 472	
	Average Annual Rate Impact								
	2024-2030 (%)	1.9%	2.9%		2.3%			2.2%	
	2024-2040 (%)	1.5%	1.5%		1.5%			1.5%	
	2024-2055 (%)	1.6%	1.5%		1.6%			1.6%	
	NPV CO2 2021-2055 ($M)	$ 8,279	$ 5,925		$ 6,052			$ 6,297	
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 45,654	$ 43,983		$ 43,793			$ 44,145	
	PVRR Utility Cost + NPV CO2 Delta vs. SCC 1								
	2021-2030 ($M)	$ -	$ (137)		$ (345)			$ (201)	
	2021-2040 ($M)	$ -	$ (1,157)		$ (1,518)			$ (1,185)	
	2021-2055 ($M)	$ -	$ (1,671)		$ (1,861)			$ (1,509)	
	Infrastructure Investment Potential ($M)								
	Generation 2021-2030 ($M)	$ 5,163	$ 7,320		$ 5,745			$ 5,965	
	Transmission 2021-2030 ($M)	$ 1,667	$ 1,667		$ 1,667			$ 1,667	
	Phase II 2030 Resource Need (MW)	(1,747)	(2,752)		(1,747)			(1,747)	
	Resource Additions 2021-2030 (Nameplate MW)								
	Wind	1,950	2,500		2,250			2,500	
	Utility-Scale Solar	1,650	2,100		1,900			2,050	
	Distributed Solar	1,158	1,158		1,158			1,158	
	Storage	300	400		450			400	
	Firm Dispatchable	1,505	2,618		1,309			1,113	
Change from Base Assumptions	**2030 CO2 % Reduction**	-2%	-2%		-1%			-1%	
	CO2 Reduction Efficiency ($/ton)	-	$ (2)		$ (11)			$ (8)	
	PVRR Utility Cost 2021-2055 ($M)	$ (1,438)	$ (1,524)		$ (1,633)			$ (1,458)	
	Average Annual Rate Impact								
	2024-2030 (%)	-0.2%	-0.2%		-0.5%			-0.3%	
	2024-2040 (%)	-0.1%	0.0%		0.0%			0.0%	
	2024-2055 (%)	-0.1%	-0.1%		-0.1%			-0.1%	
	NPV CO2 2021-2055 ($M)	$ (346)	$ (371)		$ (243)			$ (348)	
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ (1,785)	$ (1,894)		$ (1,876)			$ (1,807)	
	Infrastructure Investment Potential ($M)								
	Generation 2021-2030 ($M)	$ 882	$ 1,098		$ 227			$ 586	
	Transmission 2021-2030 ($M)	$ -	$ -		$ -			$ -	
	Phase II 2030 Resource Need (MW)	-	-		(0)			-	
	Resource Additions 2021-2030 (Nameplate MW)								
	Wind	300	150		(50)			200	
	Utility-Scale Solar	500	550		400			500	
	Distributed Solar	-	-		-			-	
	Storage	(100)	(50)		-			-	
	Firm Dispatchable	229	266		(259)			(163)	

Table 2.13-10 ERP and CEP Portfolios Reoptimized with No New Gas Resources

SCC Optimized Portfolios
$0/ton 8760-dispatch
50% ownership

Preferred Plan (SCC 7)

		SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
	Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
No New Gas Resources	**2030 CO2 % Reduction**	-76%	-94%		-91%			-89%	
	CO2 Reduction Efficiency ($/ton)	-	$ 85		$ 22			$ 27	
	PVRR Utility Cost 2021-2055 ($M)	$ 44,680	$ 47,984		$ 45,053			$ 45,635	
	PVRR Utility Cost Delta vs. SCC 1								
	2021-2030 ($M)	$ -	$ 491		$ 166			$ 128	
	2021-2040 ($M)	$ -	$ 2,280		$ 352			$ 294	
	2021-2055 ($M)	$ -	$ 3,304		$ 373			$ 955	
	Average Annual Rate Impact								
	2024-2030 (%)	3.2%	5.0%		3.6%			3.4%	
	2024-2040 (%)	2.2%	2.7%		2.2%			2.4%	
	2024-2055 (%)	2.4%	2.6%		2.4%			2.6%	
	NPV CO2 2021-2055 ($M)	$ 7,803	$ 5,408		$ 5,524			$ 5,882	
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 52,483	$ 53,392		$ 50,577			$ 51,517	
	PVRR Utility Cost + NPV CO2 Delta vs. SCC 1								
	2021-2030 ($M)	$ -	$ 105		$ (336)			$ (187)	
	2021-2040 ($M)	$ -	$ 235		$ (1,595)			$ (1,281)	
	2021-2055 ($M)	$ -	$ 909		$ (1,906)			$ (966)	
	Infrastructure Investment Potential ($M)								
	Generation 2021-2030 ($M)	$ 5,126	$ 5,944		$ 5,757			$ 5,771	
	Transmission 2021-2030 ($M)	$ 1,667	$ 1,667		$ 1,667			$ 1,667	
	Phase II 2030 Resource Need (MW)	(1,747)	(2,752)		(1,747)			(1,747)	
	Resource Additions 2021-2030 (Nameplate MW)								
	Wind	2,600	3,300		3,150			3,150	
	Utility-Scale Solar	2,000	2,000		2,000			2,000	
	Distributed Solar	1,158	1,158		1,158			1,158	
	Storage	3,200	6,900		2,950			2,900	
	Firm Dispatchable	-	-		-			-	
Change from Base Assumptions	**2030 CO2 % Reduction**	-7%	-6%		-5%			-5%	
	CO2 Reduction Efficiency ($/ton)	-	$ 39		$ (12)			$ (11)	
	PVRR Utility Cost 2021-2055 ($M)	$ 5,866	$ 8,402		$ 5,680			$ 6,330	
	Average Annual Rate Impact								
	2024-2030 (%)	1.1%	1.9%		0.8%			0.9%	
	2024-2040 (%)	0.7%	1.2%		0.7%			0.8%	
	2024-2055 (%)	0.8%	1.0%		0.8%			0.9%	
	NPV CO2 2021-2055 ($M)	$ (822)	$ (888)		$ (772)			$ (764)	
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 5,044	$ 7,514		$ 4,908			$ 5,566	
	Infrastructure Investment Potential ($M)								
	Generation 2021-2030 ($M)	$ 845	$ (279)		$ 238			$ 392	
	Transmission 2021-2030 ($M)	$ -	$ -		$ -			$ -	
	Phase II 2030 Resource Need (MW)	-	-		(0)			-	
	Resource Additions 2021-2030 (Nameplate MW)								
	Wind	950	950		850			850	
	Utility-Scale Solar	850	450		500			450	
	Distributed Solar	-	-		-			-	
	Storage	2,800	6,450		2,500			2,500	
	Firm Dispatchable	(1,276)	(2,352)		(1,568)			(1,276)	

Table 2.13-11 ERP and CEP Portfolios Reoptimized with Lower Hydrogen Costs

SCC Optimized Portfolios
$0/ton 8760-dispatch
50% ownership

Preferred Plan (SCC 7)

	Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
Lower Hydrogen Costs	**2030 CO2 % Reduction**	-69%	-88%		-87%			-84%	
	CO2 Reduction Efficiency ($/ton)	-	$ 41		$ 30			$ 32	
	PVRR Utility Cost 2021-2055 ($M)	$ 38,060	$ 38,800		$ 38,566			$ 38,525	
	PVRR Utility Cost Delta vs. SCC 1								
	2021-2030 ($M)	$ -	$ 235		$ 247			$ 170	
	2021-2040 ($M)	$ -	$ 921		$ 592			$ 449	
	2021-2055 ($M)	$ -	$ 740		$ 506			$ 464	
	Average Annual Rate Impact								
	2024-2030 (%)	2.1%	3.1%		2.8%			2.6%	
	2024-2040 (%)	1.5%	1.5%		1.5%			1.5%	
	2024-2055 (%)	1.5%	1.4%		1.4%			1.4%	
	NPV CO2 2021-2055 ($M)	$ 8,609	$ 6,337		$ 6,336			$ 6,688	
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 46,669	$ 45,137		$ 44,903			$ 45,213	
	PVRR Utility Cost + NPV CO2 Delta vs. SCC 1								
	2021-2030 ($M)	$ -	$ (149)		$ (296)			$ (183)	
	2021-2040 ($M)	$ -	$ (1,045)		$ (1,393)			$ (1,167)	
	2021-2055 ($M)	$ -	$ (1,532)		$ (1,766)			$ (1,456)	
	Infrastructure Investment Potential ($M)								
	Generation 2021-2030 ($M)	$ 4,311	$ 6,223		$ 5,519			$ 5,378	
	Transmission 2021-2030 ($M)	$ 1,667	$ 1,667		$ 1,667			$ 1,667	
	Phase II 2030 Resource Need (MW)	(1,747)	(2,752)		(1,747)			(1,747)	
	Resource Additions 2021-2030 (Nameplate MW)								
	Wind	1,750	2,350		2,300			2,300	
	Utility-Scale Solar	1,150	1,550		1,500			1,550	
	Distributed Solar	1,158	1,158		1,158			1,158	
	Storage	350	450		450			400	
	Firm Dispatchable	1,372	2,352		1,568			1,276	
Change from Base Assumptions	**2030 CO2 % Reduction**	0%	0%		0%			0%	
	CO2 Reduction Efficiency ($/ton)	-	$ (5)		$ (4)			$ (6)	
	PVRR Utility Cost 2021-2055 ($M)	$ (753)	$ (782)		$ (807)			$ (781)	
	Average Annual Rate Impact								
	2024-2030 (%)	0.0%	0.0%		0.0%			0.0%	
	2024-2040 (%)	0.0%	0.0%		0.0%			0.0%	
	2024-2055 (%)	-0.2%	-0.2%		-0.2%			-0.2%	
	NPV CO2 2021-2055 ($M)	$ (17)	$ 41		$ 41			$ 42	
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ (770)	$ (740)		$ (766)			$ (739)	
	Infrastructure Investment Potential ($M)								
	Generation 2021-2030 ($M)	$ 30	$ -		$ -			$ -	
	Transmission 2021-2030 ($M)	$ -	$ -		$ -			$ -	
	Phase II 2030 Resource Need (MW)	-	-		-			-	
	Resource Additions 2021-2030 (Nameplate MW)								
	Wind	100	-		-			-	
	Utility-Scale Solar	-	-		-			-	
	Distributed Solar	-	-		-			-	
	Storage	(50)	-		-			-	
	Firm Dispatchable	96	-		-			-	

Table 2.13-12 ERP and CEP Portfolios Reoptimized using Expanded Market Access

	SCC Optimized Portfolios $0/ton 8760-dispatch *50% ownership*							*Preferred Plan*	
	Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
Expanded Market Access	**2030 CO2 % Reduction**	-70%	-89%		-87%			-85%	
	CO2 Reduction Efficiency ($/ton)	-	$ 40		$ 24			$ 30	
	PVRR Utility Cost 2021-2055 ($M)	$ 38,100	$ 38,885		$ 38,614			$ 38,639	
	PVRR Utility Cost Delta vs. SCC 1								
	2021-2030 ($M)	$ -	$ 237		$ 198			$ 163	
	2021-2040 ($M)	$ -	$ 924		$ 529			$ 505	
	2021-2055 ($M)	$ -	$ 786		$ 514			$ 539	
	Average Annual Rate Impact								
	2024-2030 (%)	2.2%	3.1%		2.6%			2.6%	
	2024-2040 (%)	1.5%	1.5%		1.5%			1.5%	
	2024-2055 (%)	1.6%	1.6%		1.6%			1.6%	
	NPV CO2 2021-2055 ($M)	$ 8,515	$ 6,203		$ 6,266			$ 6,508	
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 46,614	$ 45,088		$ 44,880			$ 45,147	
	PVRR Utility Cost + NPV CO2 Delta vs. SCC 1								
	2021-2030 ($M)	$ -	$ (156)		$ (340)			$ (198)	
	2021-2040 ($M)	$ -	$ (1,063)		$ (1,408)			$ (1,177)	
	2021-2055 ($M)	$ -	$ (1,526)		$ (1,735)			$ (1,467)	
	Infrastructure Investment Potential ($M)								
	Generation 2021-2030 ($M)	$ 4,560	$ 6,451		$ 5,231			$ 5,564	
	Transmission 2021-2030 ($M)	$ 1,667	$ 1,667		$ 1,667			$ 1,667	
	Phase II 2030 Resource Need (MW)	(1,747)	(2,752)		(1,747)			(1,747)	
	Resource Additions 2021-2030 (Nameplate MW)								
	Wind	1,850	2,450		2,300			2,500	
	Utility-Scale Solar	1,350	1,800		1,700			1,800	
	Distributed Solar	1,158	1,158		1,158			1,158	
	Storage	200	300		250			200	
	Firm Dispatchable	1,568	2,409		1,233			1,372	
Change from Base Assumptions	**2030 CO2 % Reduction**	-1%	-1%		0%			-1%	
	CO2 Reduction Efficiency ($/ton)	-	$ (6)		$ (10)			$ (8)	
	PVRR Utility Cost 2021-2055 ($M)	$ (714)	$ (696)		$ (760)			$ (667)	
	Average Annual Rate Impact								
	2024-2030 (%)	0.1%	0.0%		-0.2%			0.0%	
	2024-2040 (%)	0.0%	0.0%		0.0%			0.0%	
	2024-2055 (%)	-0.1%	-0.1%		-0.1%			-0.1%	
	NPV CO2 2021-2055 ($M)	$ (111)	$ (93)		$ (30)			$ (138)	
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ (825)	$ (789)		$ (789)			$ (805)	
	Infrastructure Investment Potential ($M)								
	Generation 2021-2030 ($M)	$ 278	$ 229		$ (288)			$ 186	
	Transmission 2021-2030 ($M)	$ -	$ -		$ -			$ -	
	Phase II 2030 Resource Need (MW)	0	-		(0)			-	
	Resource Additions 2021-2030 (Nameplate MW)								
	Wind	200	100		-			200	
	Utility-Scale Solar	200	250		200			250	
	Distributed Solar	-	-		-			-	
	Storage	(200)	(150)		(200)			(200)	
	Firm Dispatchable	292	57		(335)			96	

SCC Optimized Portfolios Sensitivity Analysis Conclusions

There are eight sensitivity results presented above in Tables 2.13-5 through 2.13-12 for the SCC Optimized portfolios to inform how the cost or benefit of a portfolio was affected by a change in input assumption. As can be seen through a review and comparison from the color mapping of sensitivity results, the Company's Preferred Plan (SCC 7) performs well across multiple futures which vary from the base assumptions. Based on CO_2 emission reductions and PVRR Utility Costs, SCC 7 consistently is a high-ranking portfolio and the sensitivity analysis confirms this conclusion.

The sensitivity analysis has significantly different assumptions than the base assumptions presented in Table 2.13-2. These different assumptions affect the ERP portfolios and the CEP portfolios. For example, the No New Gas Sensitivity ERP Portfolio, when compared to the Base Assumptions ERP Portfolio, has a PVRR Utility Cost increase of $5.9 billion. The material change in costs and carbon reductions of the ERP portfolios makes relative comparisons such as the PVRR Utility Cost Delta vs SCC 1 and the CO2 Reduction Efficiency within the sensitivity analysis not directly comparable to the base assumption results in Table 2.13-2.

$0/ton Optimized Portfolios Sensitivity Results

Table 2.13-13 ERP and CEP Portfolios Repriced Using High Gas Prices

$0/ton Optimized Portfolios
$0/ton 8760-dispatch
50% ownership

	Portfolio	$0/ton 1	$0/ton 2	$0/ton 3	$0/ton 4	$0/ton 5	$0/ton 6	$0/ton 7	$0/ton 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
High Gas Prices	**2030 CO2 % Reduction**	-62%	-81%	-81%	-81%	-81%	-81%	-81%	-81%
	CO2 Reduction Efficiency ($/ton)	-	$ 44	$ 40	$ 30	$ 34	$ 33	$ 32	$ 27
	PVRR Utility Cost 2021-2055 ($M)	$ 39,056	$ 39,815	$ 39,798	$ 39,700	$ 39,782	$ 39,682	$ 39,664	$ 39,821
	PVRR Utility Cost Delta vs. $0/ton 1								
	2021-2030 ($M)	$ -	$ 249	$ 171	$ 239	$ 233	$ 183	$ 186	$ 286
	2021-2040 ($M)	$ -	$ 947	$ 747	$ 695	$ 838	$ 583	$ 621	$ 736
	2021-2055 ($M)	$ -	$ 759	$ 742	$ 644	$ 726	$ 626	$ 608	$ 765
	Average Annual Rate Impact								
	2024-2030 (%)	1.9%	2.9%	2.5%	2.5%	2.7%	2.5%	2.4%	2.3%
	2024-2040 (%)	1.6%	1.6%	1.7%	1.6%	1.6%	1.7%	1.6%	1.7%
	2024-2055 (%)	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.6%
	NPV CO2 2021-2055 ($M)	$ 9,128	$ 7,068	$ 7,158	$ 6,941	$ 6,989	$ 7,047	$ 7,065	$ 6,779
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 48,184	$ 46,884	$ 46,956	$ 46,641	$ 46,770	$ 46,729	$ 46,730	$ 46,599
	PVRR Utility Cost + NPV CO2 Delta vs. $0/ton 1								
	2021-2030 ($M)	$ -	$ (132)	$ (118)	$ (283)	$ (227)	$ (191)	$ (197)	$ (383)
	2021-2040 ($M)	$ -	$ (840)	$ (950)	$ (1,227)	$ (1,026)	$ (1,208)	$ (1,169)	$ (1,342)
	2021-2055 ($M)	$ -	$ (1,301)	$ (1,228)	$ (1,543)	$ (1,414)	$ (1,455)	$ (1,455)	$ (1,585)
Change from Base Assumptions	**2030 CO2 % Reduction**	0%	0%	0%	0%	0%	0%	0%	0%
	CO2 Reduction Efficiency ($/ton)	-	$ 5	$ 4	$ 6	$ 6	$ 3	$ 4	$ 4
	PVRR Utility Cost 2021-2055 ($M)	$ 775	$ 940	$ 900	$ 1,008	$ 990	$ 769	$ 912	$ 923
	Average Annual Rate Impact								
	2024-2030 (%)	0.1%	0.2%	0.2%	0.3%	0.2%	0.2%	0.2%	0.2%
	2024-2040 (%)	0.1%	0.2%	0.2%	0.2%	0.2%	0.1%	0.2%	0.2%
	2024-2055 (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	NPV CO2 2021-2055 ($M)	$ 22	$ 17	$ 17	$ 18	$ 18	$ 20	$ 19	$ 21
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 797	$ 957	$ 917	$ 1,025	$ 1,008	$ 789	$ 931	$ 944

Table 2.13-14 ERP and CEP Portfolios Repriced Using Low Gas Prices

	$0/ton Optimized Portfolios **$0/ton 8760-dispatch** ***50% ownership***								
	Portfolio	$0/ton 1	$0/ton 2	$0/ton 3	$0/ton 4	$0/ton 5	$0/ton 6	$0/ton 7	$0/ton 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
Low Gas Prices	**2030 CO2 % Reduction**	-63%	-81%	-81%	-81%	-81%	-81%	-81%	-81%
	CO2 Reduction Efficiency ($/ton)	-	$ 36	$ 34	$ 19	$ 24	$ 27	$ 25	$ 21
	PVRR Utility Cost 2021-2055 ($M)	$ 37,703	$ 38,167	$ 38,222	$ 37,930	$ 38,043	$ 38,339	$ 38,066	$ 38,202
	PVRR Utility Cost Delta vs. $0/ton 1								
	2021-2030 ($M)	$ -	$ 197	$ 137	$ 146	$ 159	$ 145	$ 137	$ 214
	2021-2040 ($M)	$ -	$ 695	$ 568	$ 337	$ 497	$ 621	$ 420	$ 514
	2021-2055 ($M)	$ -	$ 464	$ 519	$ 228	$ 340	$ 637	$ 364	$ 499
	Average Annual Rate Impact								
	2024-2030 (%)	1.6%	2.5%	2.1%	2.0%	2.3%	2.2%	2.0%	1.9%
	2024-2040 (%)	1.4%	1.3%	1.4%	1.2%	1.2%	1.5%	1.3%	1.3%
	2024-2055 (%)	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
	NPV CO2 2021-2055 ($M)	$ 9,060	$ 7,021	$ 7,111	$ 6,899	$ 6,945	$ 6,999	$ 7,019	$ 6,735
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 46,763	$ 45,188	$ 45,333	$ 44,829	$ 44,988	$ 45,339	$ 45,085	$ 44,937
	PVRR Utility Cost + NPV CO2 Delta vs. $0/ton 1								
	2021-2030 ($M)	$ -	$ (170)	$ (139)	$ (359)	$ (287)	$ (214)	$ (232)	$ (440)
	2021-2040 ($M)	$ -	$ (1,070)	$ (1,107)	$ (1,559)	$ (1,343)	$ (1,146)	$ (1,347)	$ (1,538)
	2021-2055 ($M)	$ -	$ (1,575)	$ (1,429)	$ (1,934)	$ (1,775)	$ (1,424)	$ (1,677)	$ (1,826)
Change from Base Assumptions	**2030 CO2 % Reduction**	-1%	0%	0%	0%	0%	0%	0%	0%
	CO2 Reduction Efficiency ($/ton)	$ -	$ (3)	$ (3)	$ (5)	$ (4)	$ (2)	$ (3)	$ (3)
	PVRR Utility Cost 2021-2055 ($M)	$ (578)	$ (708)	$ (676)	$ (762)	$ (748)	$ (574)	$ (686)	$ (696)
	Average Annual Rate Impact								
	2024-2030 (%)	-0.1%	-0.2%	-0.2%	-0.2%	-0.2%	-0.1%	-0.2%	-0.2%
	2024-2040 (%)	-0.1%	-0.1%	-0.1%	-0.2%	-0.1%	-0.1%	-0.1%	-0.1%
	2024-2055 (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	NPV CO2 2021-2055 ($M)	$ (47)	$ (30)	$ (30)	$ (25)	$ (26)	$ (27)	$ (27)	$ (23)
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ (625)	$ (739)	$ (706)	$ (787)	$ (774)	$ (601)	$ (713)	$ (719)

Table 2.13-15 ERP and CEP Portfolios Reoptimized with High Load

$0/ton Optimized Portfolios
$0/ton 8760-dispatch
50% ownership

	Portfolio	$0/ton 1	$0/ton 2	$0/ton 3	$0/ton 4	$0/ton 5	$0/ton 6	$0/ton 7	$0/ton 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
High Load	**2030 CO2 % Reduction**	-60%	-81%	-81%	-81%	-81%	-81%	-81%	-81%
High Load	**CO2 Reduction Efficiency ($/ton)**	-	$ 35	$ 42	$ 35	$ 33	$ 36	$ 35	$ 28
High Load	**PVRR Utility Cost 2021-2055 ($M)**	$ 42,834	$ 43,374	$ 43,475	$ 43,293	$ 43,301	$ 43,724	$ 43,338	$ 43,491
High Load	**PVRR Utility Cost Delta vs. $0/ton 1**								
High Load	2021-2030 ($M)	$ -	$ 206	$ 190	$ 277	$ 229	$ 203	$ 195	$ 290
High Load	2021-2040 ($M)	$ -	$ 752	$ 667	$ 574	$ 718	$ 804	$ 529	$ 642
High Load	2021-2055 ($M)	$ -	$ 540	$ 641	$ 459	$ 467	$ 890	$ 504	$ 657
High Load	**Average Annual Rate Impact**								
High Load	2024-2030 (%)	1.1%	2.0%	1.9%	1.7%	1.9%	1.9%	1.7%	1.7%
High Load	2024-2040 (%)	0.8%	0.7%	0.8%	0.7%	0.7%	0.9%	0.7%	0.8%
High Load	2024-2055 (%)	1.4%	1.3%	1.3%	1.4%	1.3%	1.4%	1.4%	1.3%
High Load	**NPV CO2 2021-2055 ($M)**	$ 9,375	$ 7,365	$ 7,444	$ 7,268	$ 7,272	$ 7,365	$ 7,400	$ 7,119
High Load	**PVRR Utility Cost + NPV CO2 2021-2055 ($M)**	$ 52,208	$ 50,739	$ 50,919	$ 50,562	$ 50,574	$ 51,089	$ 50,738	$ 50,610
High Load	**PVRR Utility Cost + NPV CO2 Delta vs. $0/ton 1**								
High Load	2021-2030 ($M)	$ -	$ (191)	$ (119)	$ (252)	$ (230)	$ (180)	$ (176)	$ (363)
High Load	2021-2040 ($M)	$ -	$ (1,032)	$ (1,038)	$ (1,323)	$ (1,158)	$ (942)	$ (1,220)	$ (1,389)
High Load	2021-2055 ($M)	$ -	$ (1,469)	$ (1,290)	$ (1,647)	$ (1,635)	$ (1,120)	$ (1,470)	$ (1,599)
High Load	**Infrastructure Investment Potential ($M)**								
High Load	Generation 2021-2030 ($M)	$ 3,254	$ 4,910	$ 4,728	$ 4,373	$ 4,713	$ 5,344	$ 4,221	$ 4,221
High Load	Transmission 2021-2030 ($M)	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667
High Load	**Phase II 2030 Resource Need (MW)**	(2,009)	(3,014)	(2,514)	(2,009)	(2,509)	(2,009)	(2,009)	(2,009)
High Load	**Resource Additions 2021-2030 (Nameplate MW)**								
High Load	Wind	1,000	1,350	1,650	1,450	1,400	2,350	1,600	1,600
High Load	Utility-Scale Solar	800	1,050	1,100	1,100	1,100	1,400	1,100	1,100
High Load	Distributed Solar	1,158	1,158	1,158	1,158	1,158	1,158	1,158	1,158
High Load	Storage	50	50	50	100	50	150	50	50
High Load	Firm Dispatchable	1,960	3,073	2,548	2,093	2,681	1,764	1,960	1,960
Change from Base Assumptions	**2030 CO2 % Reduction**	3%	1%	0%	0%	0%	0%	0%	0%
Change from Base Assumptions	**CO2 Reduction Efficiency ($/ton)**	-	$ (4)	$ 5	$ 11	$ 5	$ 6	$ 7	$ 5
Change from Base Assumptions	**PVRR Utility Cost 2021-2055 ($M)**	$ 4,554	$ 4,499	$ 4,577	$ 4,601	$ 4,510	$ 4,810	$ 4,586	$ 4,594
Change from Base Assumptions	**Average Annual Rate Impact**								
Change from Base Assumptions	2024-2030 (%)	-0.7%	-0.7%	-0.5%	-0.5%	-0.5%	-0.5%	-0.4%	-0.4%
Change from Base Assumptions	2024-2040 (%)	-0.7%	-0.7%	-0.7%	-0.7%	-0.7%	-0.6%	-0.7%	-0.7%
Change from Base Assumptions	2024-2055 (%)	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%
Change from Base Assumptions	**NPV CO2 2021-2055 ($M)**	$ 268	$ 314	$ 303	$ 345	$ 302	$ 338	$ 354	$ 361
Change from Base Assumptions	**PVRR Utility Cost + NPV CO2 2021-2055 ($M)**	$ 4,821	$ 4,813	$ 4,880	$ 4,946	$ 4,812	$ 5,149	$ 4,940	$ 4,954
Change from Base Assumptions	**Infrastructure Investment Potential ($M)**								
Change from Base Assumptions	Generation 2021-2030 ($M)	$ 726	$ 684	$ 786	$ 1,072	$ 1,173	$ 1,158	$ 726	$ 662
Change from Base Assumptions	Transmission 2021-2030 ($M)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Change from Base Assumptions	**Phase II 2030 Resource Need (MW)**	(262)	(262)	(262)	(262)	(262)	(262)	(262)	(262)
Change from Base Assumptions	**Resource Additions 2021-2030 (Nameplate MW)**								
Change from Base Assumptions	Wind	-	350	500	450	400	650	450	450
Change from Base Assumptions	Utility-Scale Solar	700	500	50	250	500	250	50	50
Change from Base Assumptions	Distributed Solar	-	-	-	-	-	-	-	-
Change from Base Assumptions	Storage	-	-	-	50	-	150	-	(50)
Change from Base Assumptions	Firm Dispatchable	196	(196)	196	133	133	-	196	196

Table 2.13-16 ERP and CEP Portfolios Reoptimized with Low Sales

	$0/ton Optimized Portfolios $0/ton 8760-dispatch *50% ownership*								
	Portfolio	$0/ton 1	$0/ton 2	$0/ton 3	$0/ton 4	$0/ton 5	$0/ton 6	$0/ton 7	$0/ton 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
Low Sales	**2030 CO2 % Reduction**	-65%	-82%	-81%	-81%	-82%	-81%	-81%	-81%
	CO2 Reduction Efficiency ($/ton)	-	$ 41	$ 40	$ 20	$ 25	$ 27	$ 20	$ 19
	PVRR Utility Cost 2021-2055 ($M)	$ 38,529	$ 39,181	$ 39,167	$ 38,974	$ 39,047	$ 39,152	$ 38,973	$ 39,116
	PVRR Utility Cost Delta vs. $0/ton 1								
	2021-2030 ($M)	$ -	$ 208	$ 153	$ 149	$ 166	$ 143	$ 106	$ 188
	2021-2040 ($M)	$ -	$ 801	$ 619	$ 479	$ 634	$ 565	$ 431	$ 534
	2021-2055 ($M)	$ -	$ 652	$ 639	$ 445	$ 518	$ 623	$ 444	$ 588
	Average Annual Rate Impact								
	2024-2030 (%)	1.8%	2.6%	2.3%	2.1%	2.4%	2.4%	2.1%	2.0%
	2024-2040 (%)	1.5%	1.4%	1.6%	1.4%	1.4%	1.6%	1.5%	1.5%
	2024-2055 (%)	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
	NPV CO2 2021-2055 ($M)	$ 8,918	$ 6,904	$ 6,992	$ 6,778	$ 6,811	$ 6,881	$ 6,900	$ 6,617
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 47,447	$ 46,085	$ 46,159	$ 45,752	$ 45,858	$ 46,033	$ 45,873	$ 45,734
	PVRR Utility Cost + NPV CO2 Delta vs. $0/ton 1								
	2021-2030 ($M)	$ -	$ (136)	$ (106)	$ (340)	$ (272)	$ (207)	$ (245)	$ (445)
	2021-2040 ($M)	$ -	$ (928)	$ (1,022)	$ (1,390)	$ (1,188)	$ (1,174)	$ (1,303)	$ (1,482)
	2021-2055 ($M)	$ -	$ (1,362)	$ (1,287)	$ (1,695)	$ (1,589)	$ (1,414)	$ (1,574)	$ (1,713)
	Infrastructure Investment Potential ($M)								
	Generation 2021-2030 ($M)	$ 2,305	$ 3,079	$ 3,327	$ 2,388	$ 2,685	$ 3,543	$ 2,702	$ 2,702
	Transmission 2021-2030 ($M)	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667	$ 1,667
	Phase II 2030 Resource Need (MW)	(1,436)	(2,441)	(1,941)	(1,436)	(1,936)	(1,436)	(1,436)	(1,436)
	Resource Additions 2021-2030 (Nameplate MW)								
	Wind	1,000	1,000	1,000	1,000	1,000	1,350	1,000	1,000
	Utility-Scale Solar	-	50	700	100	100	900	650	650
	Distributed Solar	1,556	1,556	1,556	1,556	1,556	1,556	1,556	1,556
	Storage	50	50	50	50	50	100	50	50
	Firm Dispatchable	1,568	2,548	2,156	1,568	1,960	1,568	1,372	1,372
Change from Base Assumptions	**2030 CO2 % Reduction**	-2%	0%	0%	0%	-1%	0%	0%	0%
	CO2 Reduction Efficiency ($/ton)	-	$ 1	$ 4	$ (4)	$ (3)	$ (2)	$ (8)	$ (5)
	PVRR Utility Cost 2021-2055 ($M)	$ 248	$ 305	$ 269	$ 282	$ 256	$ 238	$ 221	$ 218
	Average Annual Rate Impact								
	2024-2030 (%)	0.0%	-0.2%	0.0%	-0.1%	-0.1%	0.0%	-0.1%	-0.1%
	2024-2040 (%)	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%
	2024-2055 (%)	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
	NPV CO2 2021-2055 ($M)	$ (189)	$ (147)	$ (149)	$ (146)	$ (160)	$ (145)	$ (146)	$ (141)
	PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 60	$ 158	$ 120	$ 136	$ 96	$ 93	$ 75	$ 78
	Infrastructure Investment Potential ($M)								
	Generation 2021-2030 ($M)	$ (223)	$ (1,147)	$ (615)	$ (913)	$ (856)	$ (642)	$ (793)	$ (857)
	Transmission 2021-2030 ($M)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Phase II 2030 Resource Need (MW)	311	311	311	311	311	311	311	311
	Resource Additions 2021-2030 (Nameplate MW)								
	Wind	-	-	(150)	-	-	(350)	(150)	(150)
	Utility-Scale Solar	(100)	(500)	(350)	(750)	(500)	(250)	(400)	(400)
	Distributed Solar	399	399	399	399	399	399	399	399
	Storage	-	-	-	-	-	100	-	(50)
	Firm Dispatchable	(196)	(721)	(196)	(392)	(588)	(196)	(392)	(392)

$0/ton Optimized Portfolios Sensitivity Analysis Conclusions

There are four sensitivity results presented above in Tables 2.13-13 through 2.13-16 for the $0/ton Optimized portfolios to inform how the cost or benefit of a portfolio was affected by a change in input assumption. While the $0/ton Optimized portfolios in general add fewer renewables and achieve lower CO_2 reductions than the Company's Preferred CEP Portfolio, the coal actions recommended by the Company, which are represented in the $0/ton 7 portfolio, consistently rank high on limiting cost impacts.

The sensitivity analysis has significantly different assumptions than the base assumptions presented in Table 2.13-4. These different assumptions affect the ERP portfolios and the CEP portfolios. For example, the High Load Sensitivity ERP Portfolio, when compared to the Base Assumptions ERP Portfolio, has a PVRR Utility Cost increase of $4.6 billion. The material change in costs and carbon reductions of the ERP portfolios makes relative comparisons such as the PVRR Utility Cost Delta vs $0/ton 1 and the CO2 Reduction Efficiency within the sensitivity analysis not directly comparable to the base assumption results in Table 2.13-4.

Craig 2 and Hayden 1 & 2 Retirement Discussion

Hayden Unit 1 and Unit 2

In January 2021, Public Service announced its plans for the early retirement of Hayden Generating Station earlier than planned. Hayden Generating Station is a 441 MW facility (179 MW Unit 1 and 262 MW Unit 2) located in Hayden, Colorado. Hayden has two owners in addition to Public Service, including PacifiCorp and Salt River Project. Xcel Energy has full operational control and owns approximately 75 percent of Unit 1 and 37 percent of Unit 2.

Public Service and its partners have agreed on a proposed plan to retire Unit 2 by the end of 2027 and Unit 1 by the end of 2028. The original retirement dates for Unit 1 and Unit 2 were 2030 and 2036, respectively.

Craig Unit 2

In July 2020, Tri-State, the operator and majority owner of the Craig Station, located in Craig, Colorado, announced that the five owners of the 410 MW Craig Unit 2 unanimously agreed on a September 30, 2028 retirement date.

Craig Station Units 1 and 2 make up the Yampa Project, jointly owned by PacifiCorp, Platte River Power Authority, Salt River Project, Tri-State and Xcel Energy – Colorado. Xcel Energy owns approximately 10%, or 40 MW of Craig 2. The Yampa Project owners previously announced the retirement of the 427 MW Unit 1 by the end of 2025. Craig Unit 3, which is entirely owned by Tri-State, will retire by 2030 as announced by Tri-State.

Costs and Benefits of Craig 2 and Hayden 1 & 2 Retirements

The Company performed EnCompass modeling to determine the costs and benefits of the decisions to retire Craig 2 and Hayden 1 & 2 ahead of their scheduled retirement dates, with Craig 2 retiring eleven years ahead of schedule, Hayden 1 two years ahead of schedule, and Hayden 2 nine years ahead of schedule. The analysis included only the Company's ownership shares of Craig 2 and Hayden 1 & 2.

Table 2.13-17 Craig 2 and Hayden 1 & 2 Key Data

Unit	Total (MW)	Public Service Ownership (MW)	PSCo Share (%)	Retirement Date (EOY)	Original Retirement Date (EOY)	Unit Life Decrease (# of Years)	Location
Craig 2	410	40	10% - Minority	2028	2039	11	Moffat County CO
Hayden 1	179	135	75% - Majority	2028	2030	2	Route County CO
Hayden 2	262	98	37% - Minority	2027	2036	9	Route County CO

The Craig & Hayden analysis started with the Company's Preferred CEP portfolio (SCC 7) and the corresponding baseload retirement plan under $0/ton assumptions ($0/ton 7). In these portfolios, Craig and Hayden were already assumed to be retiring at the accelerated dates, so the Company developed two additional scenarios in which the Craig and Hayden units reverted back to their original retirement dates to provide the necessary comparisons. All scenarios include the coal actions of converting Pawnee to natural gas EOY 2027 and retiring Comanche 3 EOY 2039 with reduced operations.

The first additional modeling scenario changes the retirement date assumptions for both Craig 2 and Hayden 1 & 2 to their original retirement dates and reoptimizes the generic resource selections. The second additional modeling scenario changes the retirement dates for only Hayden 1 & 2 to their original retirement dates and reoptimizes the generic resource selections. These additional scenarios' expansion plans (Step 1) were developed using both SCC and $0/ton cost assumptions for CO_2 emissions and were then run through production costing (Step 2) assuming $0/ton 8760-dispatch.

Proxy costs for a Workforce Transition Plan and a Community Assistance Plan are included in the costs of for Hayden 1 & 2 in the base ERP analysis[37]. The additional scenarios reflecting the original retirement dates for Hayden 1 & 2 do include a Workforce Transition Plan tied to the original retirement dates, but do not include a Community Assistance Plan given that the units would be running until the conclusion of their respective book lives.

[37] The Company did not include these costs for Craig 2 as it does not hold a majority interest and is not the designated operator of this facility.

SCC Analysis

Tables 2.13-18 through 2.13-20 show the costs and benefits of the decision to retire PSCo's shares of Craig 2 and Hayden 1 & 2 ahead of schedule by comparing the base Preferred Plan (SCC 7) and the two additional scenarios that reflect the original retirement dates. The original retirement dates are labeled BAU in the following tables. Table 2.13-18 shows the combined results for all three units, and tables 2.13-19 and 2.13-20 show the results for the plants individually.

As can be seen from the tables, all retirements show net benefits when the cost of carbon is included. The Craig 2 retirement analysis shows small cost savings when only utility costs are considered.

Table 2.13-18 SCC Craig 2 and Hayden 1 & 2 Retirement Decision Costs and Benefits

Portfolios	Craig 2 Retirement Date (EOY)	Hayden 1 Retirement Date (EOY)	Hayden 2 Retirement Date (EOY)	PVRR Utility Cost 2021-2055 ($M)	PVRR Utility Cost + NPV CO2 2021-2055 ($M)
SCC 7	2028	2028	2027	$ 39,306	$ 45,951
SCC 7 + Craig 2 BAU + Hayden BAU	2039	2030	2036	$ 39,188	$ 46,016
Costs / (Benefits) of Craig 2 + Hayden 1 & 2 Retirement				$ 118	$ (65)

Table 2.13-19 SCC Hayden 1 & 2 Only Retirement Decision Costs and Benefits

Portfolios	Craig 2 Retirement Date (EOY)	Hayden 1 Retirement Date (EOY)	Hayden 2 Retirement Date (EOY)	PVRR Utility Cost 2021-2055 ($M)	PVRR Utility Cost + NPV CO2 2021-2055 ($M)
SCC 7	2028	2028	2027	$ 39,306	$ 45,951
SCC 7 + Hayden BAU	2028	2030	2036	$ 39,182	$ 45,971
Costs / (Benefits) of Hayden 1 & 2 Retirement Only				$ 124	$ (20)

Table 2.13-20 SCC Craig 2 Only Retirement Decision Costs and Benefits

Portfolios	Craig 2 Retirement Date (EOY)	Hayden 1 Retirement Date (EOY)	Hayden 2 Retirement Date (EOY)	PVRR Utility Cost 2021-2055 ($M)	PVRR Utility Cost + NPV CO2 2021-2055 ($M)
SCC 7 + Hayden BAU	2028	2030	2036	$ 39,182	$ 45,971
SCC 7 + Craig 2 BAU + Hayden BAU	2039	2030	2036	$ 39,188	$ 46,016
Costs / (Benefits) of Craig 2 Retirement Only				$ (6)	$ (45)

$0/ton CO_2 Analysis

Tables 2.13-21 through 2.13-23 show the costs and benefits of the decision to retire PSCo's shares of Craig 2 and Hayden 1 & 2 ahead of schedule by comparing the preferred baseload scenario under $0/ton CO_2 assumptions ($0/ton 7) and the two additional scenarios that reflect the original retirement dates. The original retirement dates are labeled BAU in the following tables. Table 2.13-21 shows the combined results for all three units, and tables 2.13-22 and 2.13-23 show the results for the plants individually.

As can be seen from the tables, the combination of all accelerated retirements shows net benefits when the cost of carbon is included, and near zero costs under a PVRR view.

Table 2.13-21 $0/ton Craig 2 and Hayden 1 & 2 Retirement Decision Costs and Benefits

Portfolios	Craig 2 Retirement Date (EOY)	Hayden 1 Retirement Date (EOY)	Hayden 2 Retirement Date (EOY)	PVRR Utility Cost 2021-2055 ($M)	PVRR Utility Cost + NPV CO2 2021-2055 ($M)
$0/ton 7	2028	2028	2027	$ 38,752	$ 45,798
$0/ton 7 + Craig 2 BAU + Hayden BAU	2039	2030	2036	$ 38,745	$ 45,856
Costs / (Benefits) of Craig 2 + Hayden 1 & 2 Retirement				$ 7	$ (58)

Table 2.13-22 $0/ton Hayden 1 & 2 Only Retirement Decision Costs and Benefits

Portfolios	Craig 2 Retirement Date (EOY)	Hayden 1 Retirement Date (EOY)	Hayden 2 Retirement Date (EOY)	PVRR Utility Cost 2021-2055 ($M)	PVRR Utility Cost + NPV CO2 2021-2055 ($M)
$0/ton 7	2028	2028	2027	$ 38,752	$ 45,798
$0/ton 7 + Hayden BAU	2028	2030	2036	$ 38,800	$ 45,907
Costs / (Benefits) of Hayden 1 & 2 Retirement Only				$ (48)	$ (108)

Table 2.13-23 $0/ton Craig 2 Only Retirement Decision Costs and Benefits

Portfolios	Craig 2 Retirement Date (EOY)	Hayden 1 Retirement Date (EOY)	Hayden 2 Retirement Date (EOY)	PVRR Utility Cost 2021-2055 ($M)	PVRR Utility Cost + NPV CO2 2021-2055 ($M)
$0/ton 7 + Hayden BAU	2028	2030	2036	$ 38,800	$ 45,907
$0/ton 7 + Craig 2 BAU + Hayden BAU	2039	2030	2036	$ 38,745	$ 45,856
Costs / (Benefits) of Craig 2 Retirement Only				$ 55	$ 51

The results of this evaluation when considering both SCC and $0/ton indicate that the costs and benefits of the early retirements of these units are relatively small. Additionally, there are offsetting results – meaning that some retirements have less impact under one view and more impact under another. These results, all fairly small, are largely a function of (1) the relatively small size of these units compared to that of the overall Public Service power supply system, (2) very small shift in retirement timing in the case of Hayden 1 and only around ten years for the other units, and (3) the influence of moving the retirement dates across the very significant "fence" of the 2030 carbon cap requiring an 80% reduction.

The full costs and benefits of the accelerated retirements of Craig 2 and Hayden 1 & 2 are reflected in the Average Annual Rate Impacts in Tables 2.13-2 through 2.13-16 for the ERP portfolio and all of the CEP portfolios, as well as in all of the other modeling in this ERP.

2.14 MODELING INPUTS AND ASSUMPTIONS

This Section summarizes the key inputs and assumptions used in the Company's Phase I modeling and as proposed to be used for Phase II modeling. Consistent with past practice, the Company proposes to update the modeling inputs and assumptions as necessary, consistent with the Commission's Phase I Decision and prior to commencement of the Phase II competitive solicitation.

Capital Structure and Discount Rate

The rates shown in Table 2.14-1 are used to calculate the capital revenue requirements of generic resources. The after-tax WACC of 6.53% is also used as the discount rate to determine levelized cost calculations and the present value of modeled costs.

Table 2.14-1 Capital Structure

Discount Rate and Capital Structure				
	Capital Structure	Allowed Return	Before Tax Electric WACC	After Tax Electric WACC
Long-Term Debt	42.72%	4.09%	1.75%	1.32%
Common Equity	55.61%	9.30%	5.17%	5.17%
Short-Term Debt	1.67%	3.33%	0.06%	0.04%
Total			**6.97%**	**6.53%**

Gas Price Forecasts

To derive the forecast of monthly delivered gas prices at Henry Hub, the Company uses a combination of market indicators such as NYMEX and various long-term price forecasts published by highly respected, industry-leading sources such as Wood Mackenzie, IHS Markit and S&P Global. The forecast is NYMEX-based for the first few years, and then it transitions into blending the NYMEX curve with the three vendor forecasts to develop a composite forecast. The Company used the following weightings for each component at various time intervals: Balance of the year plus two years uses 100% NYMEX, and years 3 and beyond uses a simple average of NYMEX, Wood Mackenzie, IHS Markit and S&P Global. The final years of the forecasts vary between vendors; IHS Markit provides data out to 2050, Wood Mackenzie and S&P Global through 2040, and NYMEX through 2031. The company uses linear extrapolation to extend the data of each forecast out to 2050. The Henry Hub is also adjusted for regional basis differentials and specific delivery costs for each generating unit to develop final model inputs.

The annual average base gas price and relevant sensitivities are summarized in Table 2.14-2. Gas price sensitivities will be run in Phase I of the 2021 ERP. High and low gas price sensitivities adjust the growth rate up and down by 50 percent from the base gas price starting in year 2023 when the long-term fundamentals-based forecasts are blended with the market information (New York Mercantile Exchange futures prices).

Table 2.14-2 Fuel and Market Price Inputs

	Base Price Forecast						Low Price Forecast					High Price Forecast				
	Fuel Price ($/mmBTu)		Market Price ($/MWh)				Fuel Price ($/mmBTu)	Market Price ($/MWh)				Fuel Price ($/mmBTu)	Market Price ($/MWh)			
Year	Generic Coal	CIG RM	4C On-Peak	4C Off-Peak	Midway On-Peak	Midway Off-Peak	CIG RM	Minn Hub On-Peak	Minn Hub Off-Peak	Midway On-Peak	Midway Off-Peak	CIG RM	Minn Hub On-Peak	Minn Hub Off-Peak	Midway On-Peak	Midway Off-Peak
2021	$1.34	$2.73	$26.96	$24.10	$24.58	$20.21	$2.73	$26.96	$24.10	$24.58	$20.21	$2.73	$26.96	$24.10	$24.58	$20.21
2022	$1.36	$2.41	$24.09	$21.86	$21.56	$17.92	$2.41	$24.09	$21.86	$21.56	$17.92	$2.41	$24.09	$21.86	$21.56	$17.92
2023	$1.41	$2.64	$25.90	$24.05	$26.10	$21.56	$2.52	$24.77	$23.00	$24.96	$20.62	$2.75	$27.03	$25.10	$27.24	$22.50
2024	$1.41	$2.73	$25.84	$24.35	$26.15	$21.81	$2.57	$24.28	$22.88	$24.57	$20.49	$2.90	$27.44	$25.86	$27.77	$23.16
2025	$1.45	$2.85	$26.78	$25.21	$27.16	$23.00	$2.62	$24.64	$23.19	$24.99	$21.16	$3.09	$29.03	$27.32	$29.44	$24.93
2026	$1.49	$2.93	$28.79	$27.56	$28.20	$24.80	$2.66	$26.14	$25.03	$25.60	$22.52	$3.22	$31.62	$30.27	$30.97	$27.24
2027	$1.53	$3.02	$28.23	$27.63	$27.70	$24.97	$2.70	$25.24	$24.70	$24.76	$22.32	$3.37	$31.49	$30.82	$30.90	$27.85
2028	$1.57	$3.12	$28.05	$28.62	$28.22	$26.51	$2.75	$24.66	$25.16	$24.81	$23.31	$3.54	$31.79	$32.44	$31.99	$30.05
2029	$1.62	$3.29	$28.89	$30.11	$28.96	$27.76	$2.82	$24.76	$25.80	$24.81	$23.79	$3.83	$33.59	$35.00	$33.67	$32.28
2030	$1.65	$3.46	$29.02	$31.63	$30.12	$29.83	$2.89	$24.26	$26.45	$25.18	$24.95	$4.12	$34.54	$37.65	$35.85	$35.51
2031	$1.69	$3.61	$29.78	$32.13	$30.83	$30.81	$2.96	$24.37	$26.30	$25.23	$25.21	$4.39	$36.20	$39.07	$37.49	$37.45
2032	$1.73	$3.69	$30.90	$33.12	$30.68	$31.03	$2.99	$25.03	$26.83	$24.85	$25.13	$4.53	$37.96	$40.69	$37.69	$38.12
2033	$1.77	$3.84	$31.02	$34.03	$30.69	$31.75	$3.05	$24.65	$27.04	$24.39	$25.23	$4.80	$38.82	$42.60	$38.42	$39.73
2034	$1.81	$3.97	$31.24	$34.67	$30.52	$32.25	$3.10	$24.39	$27.07	$23.83	$25.18	$5.06	$39.78	$44.15	$38.87	$41.07
2035	$1.85	$4.11	$31.62	$35.32	$30.65	$32.57	$3.15	$24.30	$27.14	$23.55	$25.03	$5.31	$40.90	$45.69	$39.64	$42.13
2036	$1.92	$4.25	$32.37	$36.36	$30.83	$33.72	$3.21	$24.45	$27.46	$23.29	$25.47	$5.59	$42.58	$47.82	$40.55	$44.35
2037	$1.97	$4.31	$32.26	$36.49	$30.89	$34.07	$3.23	$24.19	$27.37	$23.16	$25.55	$5.71	$42.75	$48.36	$40.93	$45.14
2038	$2.02	$4.45	$32.47	$36.95	$31.01	$34.42	$3.29	$23.96	$27.26	$22.88	$25.40	$5.99	$43.71	$49.74	$41.75	$46.34
2039	$2.07	$4.62	$32.51	$37.23	$30.80	$34.81	$3.35	$23.56	$26.98	$22.32	$25.22	$6.33	$44.56	$51.02	$42.22	$47.71
2040	$2.11	$4.79	$32.72	$37.91	$31.18	$35.93	$3.41	$23.27	$26.96	$22.18	$25.56	$6.69	$45.67	$52.90	$43.51	$50.14
2041	$2.17	$4.91	$33.21	$38.58	$30.92	$36.10	$3.45	$23.35	$27.12	$21.73	$25.38	$6.93	$46.90	$54.47	$43.65	$50.97
2042	$2.23	$5.11	$33.46	$38.94	$31.34	$36.72	$3.52	$23.07	$26.84	$21.60	$25.31	$7.35	$48.17	$56.05	$45.11	$52.85
2043	$2.29	$5.31	$33.62	$39.46	$31.16	$37.17	$3.59	$22.73	$26.68	$21.07	$25.13	$7.79	$49.31	$57.88	$45.70	$54.52
2044	$2.35	$5.52	$34.58	$40.56	$32.16	$37.98	$3.66	$22.95	$26.92	$21.34	$25.20	$8.24	$51.66	$60.60	$48.05	$56.74
2045	$2.40	$5.68	$34.57	$41.37	$31.73	$38.48	$3.72	$22.61	$27.05	$20.75	$25.16	$8.61	$52.41	$62.71	$48.10	$58.34
2046	$2.46	$5.86	$35.06	$41.88	$32.02	$38.81	$3.77	$22.58	$26.97	$20.62	$24.99	$9.02	$53.97	$64.45	$49.29	$59.74
2047	$2.52	$5.99	$35.39	$42.90	$32.40	$39.86	$3.82	$22.55	$27.33	$20.65	$25.40	$9.31	$55.03	$66.71	$50.39	$61.99
2048	$2.58	$6.17	$35.81	$43.26	$32.53	$40.55	$3.87	$22.49	$27.17	$20.43	$25.46	$9.73	$56.50	$68.26	$51.32	$63.97
2049	$2.65	$6.28	$35.76	$43.61	$32.50	$40.19	$3.91	$22.25	$27.14	$20.22	$25.01	$10.00	$56.94	$69.44	$51.75	$63.99
2050	$2.72	$6.42	$36.59	$44.99	$32.66	$40.71	$3.95	$22.52	$27.69	$20.10	$25.05	$10.33	$58.89	$72.40	$52.56	$65.51

**Coal prices are delivered prices, while gas and market prices are hub prices.*

Firm Fuel Charges

In the current 2021 ERP Phase I modeling, the Company applied a levelized charge of $11.98/kW-yr to all new generic gas fired resources to represent an estimate of the fixed costs associated with acquiring firm fuel supply to these generators either through firm gas supply or fuel oil backup infrastructure. The Company is currently examining this assumption and may provide an updated value for use in the Phase II modeling.

Market Prices

In addition to resources that exist within Colorado, the Company has access to markets located outside its service territory. External markets modeled include Midway (representing markets to the Colorado Front Range and Wyoming areas), Four Corners (representing Western/Southwestern areas) and SPP (through the Lamar tie). The modeling currently does not include interactions through the Lamar due to the limited nature and typically higher cost of as-available transmission along this path.

To derive the forecast of monthly On and Off-peak electricity prices, the company uses a simple average of long-term implied heat rate forecasts provided by Wood Mackenzie, IHS Energy and S&P Global. The implied heat rates, denominated in MMBtu/MWh, are then multiplied by the company's long-term natural gas price forecast at a near location to determine the On and Off-peak energy prices.

Annual average values for the Four Corners Market and Midway are summarized in Table 2.14-2 and have zero CO_2 cost assumptions

Coal Price Forecasts

Coal price forecasts are developed using two major inputs: the current coal contract volumes and prices combined with current estimates of spot market coal volumes and prices. Typically, coal volumes and prices are under contract on a plant-by-plant basis for a one to five-year term with annual spot volumes and prices filling the estimated fuel requirements of the coal plant. To derive the forecast of coal prices at mine mouth, the company uses a simple average of long-term coal price forecasts provided by JD Energy, Wood Mackenzie, IHS Energy and S&P Global. Layered on top of the coal prices are transportation charges, freeze control and dust suppressant, as required. The simple average annual coal price forecast is summarized in Table 2.14-2.

Reserve Margin

As discussed in the planning reserve margin study, in the 2021 ERP & CEP, the Company will utilize a Planning Reserve Margin of 18% applied to the 50th Percentile demand forecast. This study is provided for reference as Appendix A.

Surplus Capacity Credit

For each year in which the modeled portfolio includes firm generation capacity in excess of the planning reserve margin (i.e. the periods in which the Company is long capacity), surplus capacity will be credited at the equivalent cost of the generic CT up to an excess of 200 MW for all twelve months of the year in the Phase I alternative plan analysis and during Phase II portfolio creation. The value of the surplus capacity credit is shown below in Table 2.14-3.

Table 2.14-3 Surplus Capacity Credit

Surplus Capacity Credit	
Year	$/kw-yr
2021	$82.19
2022	$83.56
2023	$84.97
2024	$86.40
2025	$87.85
2026	$89.34
2027	$90.86
2028	$92.41
2029	$93.99
2030	$95.60
2031	$97.25
2032	$98.92
2033	$100.63
2034	$102.37
2035	$104.16
2036	$105.97
2037	$107.82
2038	$109.71
2039	$111.63
2040	$113.60
2041	$115.60
2042	$117.65
2043	$119.73
2044	$121.86
2045	$124.02
2046	$126.24
2047	$128.50
2048	$130.80
2049	$133.14
2050	$135.54

Seasonal Capacity Purchases

The Company made a generic Seasonal Capacity Purchase available in the Phase I modeling for 2024 in recognition that new generic resources would be difficult to place in service in 2024 given the regulatory timing of this proceeding. If bids are received in Phase II with in-service dates and capacity that fully meet the summer of 2024's firm capacity need, this purchase will be removed from the model. In addition, for years in which the planning reserve margin study indicated reserve margins in excess of 18%, seasonal purchases were included to cover the amount of reserves required that are in excess of 18%. For Phase II, these seasonal generic purchases will be removed from the model.

CO_2 Price Forecasts

Base modeling assumptions are either a $0/ton CO_2 proxy price or the SCC. The SCC values utilized are shown in Table 2.14-4 below. The SCC values were developed from the federal social cost of carbon, using the value calculated at a 3% discount rate, labeled as “3% Average” in the federal Technical Support Document and converted to nominal dollars per short ton to reflect the values used in modeling.

Table 2.14-4 CO_2 Cost Forecast

CO2 Costs ($ per short ton)		
Year	$0 CO2	SCC
2021	$0.00	$48.06
2022	$0.00	$50.19
2023	$0.00	$52.38
2024	$0.00	$54.64
2025	$0.00	$56.97
2026	$0.00	$59.38
2027	$0.00	$61.85
2028	$0.00	$64.40
2029	$0.00	$65.69
2030	$0.00	$68.37
2031	$0.00	$71.13
2032	$0.00	$73.98
2033	$0.00	$76.91
2034	$0.00	$79.93
2035	$0.00	$83.04
2036	$0.00	$86.24
2037	$0.00	$89.53
2038	$0.00	$92.93
2039	$0.00	$96.42
2040	$0.00	$100.01
2041	$0.00	$103.71
2042	$0.00	$105.79
2043	$0.00	$109.67
2044	$0.00	$113.67
2045	$0.00	$117.79
2046	$0.00	$122.02
2047	$0.00	$126.37
2048	$0.00	$130.85
2049	$0.00	$135.46
2050	$0.00	$140.20

Inflation / Construction Escalation Rates

The inflation rate used for construction (capital) costs, non-fuel variable O&M, fixed O&M and any other escalation factor related to general inflationary trends is the long-term forecast from HIS Economics for the "Chained Price Index for Consumer Purchases" published in the first quarter of 2020. This rate is 2.0% and will be applied throughout the entire planning period as a base assumption.

DSM Forecasts

On July 3, 2017, the Company filed an application in Proceeding No. 17A-0462EG for approval of a number of strategic issues relating to its DSM Plan, including long-term electric energy savings and demand response goals. Per the Commission's decision (Decision No. C14-0731) in the 2013 Strategic Issues proceeding (Proceeding No. 13A-0686EG), the Company has continued to use the approved demand response targets for purposes of determining resource need. Since the approved goals extend only through 2023, the current assumption is that levels of demand response remain constant after 2023 for purposes of resource need determination. Table 2.14-5 reflects the approved demand response goals and Table 2.14-6 reflects the Company's forecasted demand response capacity. The additional ordered 75 MW of energy efficiency demand reduction reflected directly in the load forecast.

Table 2.14-5 Demand Response Goals (MW)

Demand Response	2021	2022	2023
Strategic Issues DR Goal	489	503	520

Table 2.14-6 Demand Response Goals (MW)

Demand Response(MW)		
Year	Un-Adjusted For Reserve Margin	Adjusted For Reserve Margin
2021	527	622
2022	527	622
2023	561	669
2024	561	669
2025	561	662
2026	586	691
2027	586	691
2028	586	691
2029	586	691
2030	605	714
2031	605	714
2032	605	714
2033	605	714
2034	605	714
2035	605	714
2036	605	714
2037	605	714
2038	605	714
2039	605	714
2040	605	714
2041	605	714
2042	605	714
2043	605	714
2044	605	714
2045	605	714
2046	605	714
2047	605	714
2048	605	714
2049	605	714
2050	605	714

Section 2.4 details the Company's demand-side management forecasts and the policies that inform those forecasts.

Transmission Network Upgrade Costs

Estimates of transmission network upgrades costs for the Phase I generic resources are included in the generic resource cost estimates. For Phase II, transmission network upgrade costs include: (1) those within an existing switching station or substation ("station") or the creation of a new interconnection station, and (2) those outside the interconnection station. In Phase II, the Company will allocate the first type of transmission network upgrade costs fully to the proposed bid(s) requiring those upgrades. The second type of costs will be allocated on a MW pro-rata share of upgrades needed for each individual bid for Phase II analyses purposes. However, the Company will not assign transmission network upgrade costs to projects that utilize existing transmission capacity or that utilize transmission projects for which the Company has been granted a Certificate of Public Convenience and Necessity at the time of the bid evaluation or Commission approval of a portfolio of transmission expansion projects. See Sections 3.6 and Appendix C in the Volume 3 Request for Proposal documents for additional process detail.

Transmission Interconnection Costs

Estimates of transmission interconnection costs for the Phase I generic resources are included in the generic resource cost estimates. Following bid submittal in a Phase II competitive solicitation the Company will review and estimate, as necessary, both the developer-borne and the transmission-provider-borne costs for proposed projects. See Sections C.3 and C.5 and Appendix C in the Volume 3 Request for Proposal documents for additional process detail.

Generation Capacity Credit for Wind Resources

Wind resources existing at the start of 2023 receive 13.4% of generation capacity credit in Phase I and Phase II modeling based on the Company's most recent wind ELCC study. For Phase I modeling purposes, incremental, generic wind resources received generation capacity credit as shown in Table 2.14-7.

Table 2.14-7 Phase I Wind ELCC Assumptions

Generic Wind ELCC	
0-1000 MW	19.4%
> 1000 MW	14.5%

For initial Phase II portfolio selection purposes, individual, incremental wind generation resources will receive generation capacity credit consistent with the proposed nameplate capacity and ERZ as found in the Company's most recent wind ELCC study. A table of this information (found in Figure 6 and Table A-5 from the ELCC study) is provided in Table 2.14-8. ERZ-5 (50%) and ERZ-5 (44%) are the ELCCs determined for a 50% net capacity factor ("NCF") and a 44% NCF wind generator in ERZ-5, respectively. The Company will interpolate between Incremental MW as shown in Table 2.14-8 to accommodate actual Phase II proposals.

Table 2.14-8 Phase II Average ELCC Applied to Incremental Wind MW

Incremental MW	ERZ-1	ERZ-2	ERZ-3	ERZ-5 (50%)	ERZ-5 (44%)
250	15.9%	12.8%	33.6%	24.2%	17.6%
500	14.5%	12.1%	31.1%	22.6%	16.7%
1,000	12.3%	11.2%	26.9%	20.2%	15.1%
2,000	9.6%	9.9%	20.1%	16.5%	12.5%
3,000	8.1%	9.0%	15.4%	14.2%	10.8%

As the ELCC study documented the impact that generation technology, penetration, and geographic diversity has on portfolio ELCC, the actual ELCC afforded any particular bid in final Phase II modeling and portfolio selection will likely differ from the values shown in Table 2.14-8; a map illustrating the relative geographic areas of each of the four ERZs shown in the Table is included in the ELCC study. Additionally, ELCC may be adjusted for resources that propose annual net capacity factors that materially differ from the 50% annual NCF assumed in the ELCC study. See Section 2.17 for further discussion of the process through which portfolio ELCC will be determined in Phase II modeling.

Generation Capacity Credit for Solar Resources

Utility solar resources existing at the start of 2023 receive 47.9% of generation capacity credit in Phase I and Phase II modeling based on the Company's most recent solar ELCC study. For Phase I modeling purposes, incremental, generic utility solar resources received generation capacity credit as shown in Table 2.14-9.

Table 2.14-9 Phase I Generic Utility Solar ELCC

Generic Solar ELCC	
0-1000 MW	19.6%
> 1000 MW	10.5%

For initial Phase II portfolio selection purposes, individual, incremental utility solar generation resources will receive generation capacity credit consistent with the proposed nameplate capacity and solar zone as found in the Company's most recent solar ELCC study. A table of this information (found in Figure 3 and Table A-4 from the ELCC study) is provided in Table 2.14-10; a map illustrating the relative geographic areas of each of the six solar resource zones shown in the Table is included in the ELCC study. The Company will interpolate between Incremental MW as shown in Table 2.14-10 to accommodate actual Phase II proposals.

Table 2.14-10 Phase II Average ELCC Applied to Incremental Utility Solar MW

Incremental MW	MTN	NFR	SE	SFR	SLV	WS
100	21.4%	33.5%	29.3%	15.4%	28.4%	36.3%
250	19.6%	31.7%	27.4%	14.5%	26.2%	32.8%
500	16.9%	29.0%	24.3%	12.8%	22.5%	28.6%
1,000	13.3%	23.9%	19.4%	10.5%	17.2%	22.6%
2,000	9.7%	16.8%	13.7%	8.1%	11.8%	15.4%
3,000	7.8%	12.5%	10.6%	6.8%	9.3%	11.4%

Phase II ELCCs may be adjusted from the values in the table for resources that propose annual net capacity factors that materially differ from the assumed 30% annual NCF or for projects that are located distant from the metered resources used in the ELCC study. As the ELCC study documented the impact that generation technology, penetration, and geographic diversity has on portfolio ELCC, the actual ELCC assigned to any particular bid in final Phase II modeling will likely differ from the values shown in Table 2.14-10. See Section 2.16 for further discussion of the process through which portfolio ELCC will be determined in Phase II modeling.

Generation Capacity Credit for Hydro and Storage Resources

Based on the Company's most recent ELCC study, in Phase I and Phase II modeling: (1) existing hydro generation resources receive 55.4%, (2) the Company's existing Cabin Creek pumped hydro facility receives 91.7%, and (3) the storage components of solar hybrid facilities existing at the start of 2023 receive 60.4% in generation capacity credit. Generic 4-hour duration battery resources modeled in Phase I received generation capacity credit as shown in Table 2.14-11.

Table 2.14-11 Phase I Generic 4-Hour Duration Storage ELCC

Generic Battery ELCC	
0-1000 MW	55.0%
> 1000 MW	37.0%

For initial Phase II portfolio selection purposes, incremental storage resources will receive generation capacity credit consistent with the proposed nameplate capacity and duration as found in the Company's most recent ELCC study. A table of this information (found in Figure 8 and Table A-7 from the ELCC study) is provided below in Table 2.14-12. The Company will interpolate between Incremental MW and Duration values as shown in Table 2.14-12 to accommodate actual Phase II proposals for initial portfolio selection purposes. These values will apply to both standalone storage proposals and the storage component of renewable hybrid proposals.

Table 2.14-12 Phase II Average ELCC Applied to Incremental Storage

Incremental MW	2-Hour Duration	4-Hour Duration	8-Hour Duration
50	48.8%	68.1%	92.3%
100	45.9%	65.0%	90.4%
250	39.7%	58.8%	85.2%
500	32.8%	51.0%	75.1%
1,000	26.1%	39.9%	55.3%
2,000	20.0%	27.5%	35.2%
3,000	16.3%	21.3%	25.7%

As the ELCC study documented the impact that generation technology, penetration, and geographic diversity has on portfolio ELCC, the actual ELCC afforded any particular storage bid in final Phase II modeling will likely differ from the values shown in Table 2.14-12. See Section 2.16 for further discussion of the process through which portfolio ELCC will be determined in Phase II modeling.

Resource Acquisition Period

Pursuant to SB 19-236, the Company's ERP must utilize a RAP that extends through 2030. Resources must be in-service prior to the Company's summer peak reliability season to fill the 2030 resource need; therefore, resources must propose in-service dates no later than May 1, 2030.

Planning Period

Planning Period means the future period for which a utility develops its ERP and the period over which net present value of revenue requirements for resources are calculated. Pursuant to Rule 3602(k), the planning period is 20 to 40 years and begins from the date the utility files its plan with the Commission. The planning period is from March 31, 2021 – June 1, 2055. For purposes of modeling, the capacity expansion plans will be developed for 2023-2050, and the production costs from 2050 will be repeated without escalation for 5 years through 2055 and included in all NPV calculations of the plans.

SO_2 Effluent Costs and Allocations

SO_2 is controlled through the Acid Rain program in Colorado. Through this program, the Company has excess SO_2 allowances because of the use of low sulfur coal and scrubber retrofits at the Arapahoe, Cherokee, Hayden, and Valmont units. Therefore, the Company does not anticipate that it will have to purchase any allowances for SO_2 under current or reasonably foreseeable legislation. Therefore, the Company assigns no effluent costs or allocations to SO_2. SO_2 effluent costs (as measured in $/ton) will remain zero unless a major change in legislation occurs during the deliberation of the ERP.

NO_x Effluent Costs and Allocations

There is no trading program for sources of NO_x in Colorado; therefore, no cost is applied to NO_x emissions. The primary programs that reduce NO_x are the Regional Haze Rule through the application of the Best Available Retrofit Technology program, which seeks to achieve further reasonable progress towards long term visibility goals in Class I areas like national parks and wilderness areas. The Denver ozone State Implementation Plan ("SIP") is also another driver for NO_x reductions. As a result, the costs of NO_x reductions are embedded in capital and operating costs of the resources included in the SIP (e.g., the Selective Catalytic Reduction additions to Pawnee and Hayden). NO_x effluent costs (as measured in $/ton) will remain zero unless a major change in legislation occurs during the deliberation of the ERP.

Mercury Effluent Costs and Allocations

Mercury is also controlled as a command and control rule through the Colorado Mercury Rule. Therefore, there is no cap and trade for mercury either and effluent costs and allocations will be assigned a zero cost in the Phase I alternative plan analysis. As with SO_2 and NO_x, costs associated with controlling these emissions were captured in the resource costs. Mercury effluent costs (as measured in $/ton) will remain zero unless a major change in legislation occurs during the deliberation of the ERP.

Spinning Reserve Requirement

Spinning Reserve is the on-line reserve capacity that is synchronized to the grid to maintain system frequency stability during contingency events and unforeseen load swings. The level of spinning reserve modeled was consistent with the NWPP requirements. The cost of spinning reserve is inherently embedded in the EnCompass model by assigning a spin requirement and the spinning capability of each resource.

Emergency Energy Costs

Emergency Energy Costs are included in the EnCompass model if there are not enough resources available to meet energy requirements. In the model, the cost was set at an arbitrary very high cost ($1 million/MWh) to ensure the model makes every effort to avoid emergency energy (which is synonymous with curtailed firm load). Emergency energy costs occur only in rare instances; however, it does appear in some plans in very small amounts. To ensure large swings in plan costs are not created by these small amounts, for purposes of determining NPV these $1 million costs were replaced in post-processing with more reasonable values of $2,000/MWh ($2020) escalating at 2%.

Wind/Solar Integration Costs and Storage Integration Credits

Table 2.14-13 provides the wind and solar integration costs for existing and generic wind and solar resources assumed in Phase I modeling. These values are based upon the Company's most recent Solar and Wind Integration Cost study which is documented in Appendix D. The wind integration costs and storage integration cost credits to be applied in Phase II bid evaluations will be increased by an additional $0.07/MWh to include the component of wind integration costs determined in the Company's prior integration cost studies for the gas storage component of such costs. Incremental storage resources receive an integration cost credit applied to the storage device's discharge MWh.

Table 2.14-13 Phase I Wind and Solar Integration Costs and Storage Integration Cost Credits

Integration Costs ($/MWh)					Integration Credit ($/MWh)
Year	Existing Wind	Generic Wind	Existing Solar	Generic Solar	Storage
2021	$1.84	$2.47	$0.30	$0.50	$2.98
2022	$1.68	$2.31	$0.20	$0.40	$2.72
2023	$1.80	$2.43	$0.27	$0.47	$2.90
2024	$1.85	$2.48	$0.30	$0.50	$2.98
2025	$1.91	$2.54	$0.34	$0.54	$3.07
2026	$1.94	$2.57	$0.36	$0.56	$3.14
2027	$1.99	$2.62	$0.39	$0.59	$3.21
2028	$2.04	$2.67	$0.42	$0.62	$3.29
2029	$2.13	$2.76	$0.47	$0.67	$3.43
2030	$2.21	$2.84	$0.52	$0.72	$3.56
2031	$2.29	$2.92	$0.57	$0.77	$3.68
2032	$2.33	$2.96	$0.59	$0.79	$3.74
2033	$2.40	$3.03	$0.63	$0.83	$3.86
2034	$2.47	$3.10	$0.67	$0.87	$3.97
2035	$2.53	$3.16	$0.71	$0.91	$4.07
2036	$2.60	$3.23	$0.76	$0.96	$4.19
2037	$2.64	$3.27	$0.78	$0.98	$4.24
2038	$2.71	$3.34	$0.82	$1.02	$4.35
2039	$2.79	$3.42	$0.87	$1.07	$4.49
2040	$2.88	$3.51	$0.92	$1.12	$4.63
2041	$2.94	$3.57	$0.96	$1.16	$4.72
2042	$3.03	$3.66	$1.01	$1.21	$4.88
2043	$3.14	$3.77	$1.08	$1.28	$5.04
2044	$3.24	$3.87	$1.14	$1.34	$5.20
2045	$3.32	$3.95	$1.19	$1.39	$5.34
2046	$3.41	$4.04	$1.24	$1.44	$5.48
2047	$3.47	$4.10	$1.28	$1.48	$5.58
2048	$3.56	$4.19	$1.33	$1.53	$5.72
2049	$3.62	$4.25	$1.37	$1.57	$5.82
2050	$3.69	$4.32	$1.41	$1.61	$5.93

Owned Unit Modeled Operating Characteristics and Costs

Company-owned units were modeled based upon their tested operating characteristics and historical or projected costs. Below is a list of operating and cost inputs for each Company-owned resource:

a. Maximum Capacity
b. Minimum Capacity Rating
c. Seasonal Deration
d. Heat Rate Profiles
e. Variable O&M
f. Fixed O&M
g. Maintenance Schedule
h. Forced Outage Rate
i. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
j. Contribution to spinning reserve
k. Fuel prices
l. Fuel delivery charges

Thermal PPA Operating Characteristics and Costs

PPA are modeled based upon their tested operating characteristics and contracted costs. Below is a list of operating and cost inputs for each thermal purchase power contract:

a. Contract term
b. Maximum Capacity
c. Minimum Capacity Rating
d. Seasonal Deration
e. Heat Rate Profiles
f. Energy Schedule
g. Capacity Payments
h. Energy Payments
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

Renewable Energy PPA Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Below is a list of operating and cost inputs for each renewable energy purchase power contract:

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity Payments
g. Energy Payments
h. Integration Costs
i. Emission rates for SO_2, NO_x, CO_2, Mercury and PM if applicable

Integration and cycling costs will be updated as addressed elsewhere in this document.

Load Forecast

A discussion of the load forecast and methodology is available in Section 2.2, and a discussion of the resource need assessment is available in Section 2.12. Table 2.14-14 below summarizes the Company's Phase I projection of resource need.

The forecast shown in Tables 2.14-15 and 2.14-16 further below do not include the impact of DG solar, as DG solar is modeled as a resource, not a load modifier.

Table 2.14-14 Public Service Resource Need Forecast

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Resource Need (MW)	-	-	-	-	-	203	672	1,354	1,411	1,474
Resource Need (MW) w/ Announced Early Coal Retirements	-	-	-	-	-	203	672	1,452	1,684	1,747

Table 2.14-15 Demand and Energy Forecast with and Without EV

Demand and Energy Forecast				
	Demand (MW)		Energy (GWh)	
Year	Forecast with EV	Forecast without EV	Forecast with EV	Forecast without EV
2021	6,856	6,847	33,010	32,943
2022	6,973	6,962	32,929	32,793
2023	6,951	6,930	33,151	32,884
2024	6,978	6,944	33,766	33,328
2025	7,031	6,985	34,170	33,567
2026	6,906	6,847	33,737	32,968
2027	6,986	6,913	34,131	33,167
2028	7,063	6,972	34,685	33,470
2029	7,130	7,015	35,104	33,570
2030	7,219	7,075	35,627	33,690
2031	7,306	7,129	36,178	33,780
2032	7,413	7,201	36,895	34,016
2033	7,478	7,230	37,462	34,081
2034	7,558	7,273	38,118	34,216
2035	7,665	7,341	38,899	34,465
2036	7,774	7,412	39,805	34,833
2037	7,862	7,461	40,516	34,998
2038	7,963	7,523	41,313	35,243
2039	8,069	7,590	42,069	35,442
2040	8,159	7,639	42,823	35,622
2041	8,216	7,656	43,379	35,593
2042	8,285	7,685	44,002	35,643
2043	8,129	7,493	43,298	34,412
2044	8,195	7,523	43,969	34,573
2045	8,245	7,535	44,466	34,522
2046	8,313	7,562	45,091	34,559
2047	8,389	7,596	45,762	34,621
2048	8,461	7,628	46,520	34,798
2049	8,509	7,640	46,991	34,759
2050	8,576	7,701	47,645	35,242

Table 2.14-16 Annual Peak Demand Forecast with EV

Annual Peak			Demand Forecast with EV				
				Summer		Winter	
Year	Month		Year	MW	Month	MW	Month
2021	7		2021	6,856	7	5,206	12
2022	7		2022	6,973	7	5,349	12
2023	7		2023	6,951	7	5,352	12
2024	7		2024	6,978	7	5,358	12
2025	7		2025	7,031	7	5,412	12
2026	7		2026	6,906	7	5,161	12
2027	7		2027	6,986	7	5,210	12
2028	7		2028	7,063	7	5,252	12
2029	7		2029	7,130	7	5,317	12
2030	7		2030	7,219	7	5,375	12
2031	7		2031	7,306	7	5,428	12
2032	7		2032	7,413	7	5,438	12
2033	7		2033	7,478	7	5,503	12
2034	7		2034	7,558	7	5,560	12
2035	7		2035	7,665	7	5,639	12
2036	7		2036	7,774	7	5,710	12
2037	7		2037	7,862	7	5,795	12
2038	7		2038	7,963	7	5,872	12
2039	7		2039	8,069	7	5,945	12
2040	7		2040	8,159	7	5,990	12
2041	7		2041	8,216	7	6,041	12
2042	7		2042	8,285	7	6,083	12
2043	7		2043	8,129	7	5,810	12
2044	7		2044	8,195	7	5,835	12
2045	7		2045	8,245	7	5,883	12
2046	7		2046	8,313	7	5,925	12
2047	7		2047	8,389	7	5,969	12
2048	7		2048	8,461	7	5,999	12
2049	7		2049	8,509	7	6,041	12
2050	7		2050	8,576	7	6,089	12

Table 2.14-17 EV Demand and Energy Forecast

EV Forecast		
Year	Demand (MW)	Energy (GWh)
2021	10	67
2022	11	137
2023	21	267
2024	34	438
2025	46	603
2026	59	769
2027	73	964
2028	91	1,214
2029	115	1,534
2030	144	1,937
2031	177	2,397
2032	212	2,879
2033	248	3,381
2034	286	3,902
2035	324	4,434
2036	362	4,973
2037	401	5,518
2038	440	6,069
2039	479	6,627
2040	519	7,202
2041	560	7,786
2042	600	8,359
2043	636	8,886
2044	671	9,397
2045	709	9,944
2046	750	10,532
2047	793	11,141
2048	834	11,723
2049	868	12,232
2050	875	12,402

**Demand values are coincident to system peak.*

Base Distributed Energy Resource Forecasts

Table 2.14-18 Distributed Solar Nameplate Capacity Forecast

Distributed Solar (Nameplate MW)			
Year	Behind the Meter	Community Gardens	Total
2021	496	118	614
2022	561	185	747
2023	629	252	882
2024	686	319	1,005
2025	726	385	1,111
2026	769	451	1,220
2027	815	516	1,331
2028	872	582	1,454
2029	950	646	1,596
2030	1,046	711	1,757
2031	1,134	775	1,910
2032	1,211	839	2,050
2033	1,291	901	2,192
2034	1,374	961	2,335
2035	1,460	1,019	2,480
2036	1,549	1,079	2,628
2037	1,641	1,135	2,776
2038	1,735	1,184	2,919
2039	1,831	1,225	3,056
2040	1,928	1,268	3,196
2041	2,023	1,293	3,316
2042	2,114	1,293	3,407
2043	2,205	1,293	3,498
2044	2,297	1,293	3,590
2045	2,387	1,293	3,680
2046	2,473	1,293	3,766
2047	2,556	1,293	3,849
2048	2,636	1,293	3,929
2049	2,715	1,293	4,008
2050	2,791	1,293	4,084

**Demand values are July numbers.*

The distributed solar and Community Solar Gardens inputs are based on the most recent Company forecasts. Distributed Solar is modeled assuming a degradation of half a percent annually in generation. Community Solar Gardens are modeled assuming a degradation of half a percent annually in generation, and a 25-year service life.

Table 2.14-19 Distributed Solar Firm Capacity Forecast

Distributed Solar (Firm MW)			
Year	**Behind the Meter**	**Community Gardens**	**Total**
2021	172	71	243
2022	195	111	306
2023	119	102	221
2024	119	103	222
2025	125	121	246
2026	130	138	269
2027	136	155	291
2028	144	171	314
2029	153	186	339
2030	164	201	365
2031	175	215	389
2032	183	228	411
2033	191	240	431
2034	200	251	450
2035	208	260	468
2036	216	270	486
2037	224	277	501
2038	231	283	514
2039	239	284	522
2040	245	285	530
2041	252	290	542
2042	257	297	554
2043	262	304	566
2044	266	310	576
2045	270	315	586
2046	274	320	594
2047	276	325	601
2048	279	329	607
2049	281	332	613
2050	282	335	617

**Demand values are coincident to system peak.*

Low Load Forecast

The forecasts shown below do not include the impact of DG solar, as DG solar is modeled as a resource, not a load modifier.

Table 2.14-20 Demand and Energy Forecast (Low)

Demand and Energy Forecast				
	Demand (MW)		Energy (GWh)	
Year	Forecast with EV	Forecast without EV	Forecast with EV	Forecast without EV
2021	6,856	6,847	33,010	32,943
2022	6,973	6,962	32,745	32,608
2023	6,936	6,915	32,874	32,607
2024	6,944	6,910	33,341	32,903
2025	6,960	6,914	33,554	32,950
2026	6,799	6,740	32,965	32,196
2027	6,855	6,782	33,255	32,292
2028	6,896	6,804	33,652	32,437
2029	6,945	6,830	34,015	32,482
2030	7,012	6,868	34,470	32,533
2031	7,076	6,899	34,950	32,552
2032	7,148	6,936	35,535	32,657
2033	7,196	6,948	36,060	32,678
2034	7,251	6,965	36,635	32,734
2035	7,319	6,996	37,276	32,842
2036	7,379	7,017	37,980	33,007
2037	7,437	7,036	38,592	33,075
2038	7,500	7,060	39,249	33,180
2039	7,573	7,093	39,889	33,262
2040	7,631	7,112	40,537	33,335
2041	7,679	7,119	41,084	33,297
2042	7,731	7,131	41,668	33,309
2043	7,555	6,919	40,917	32,030
2044	7,593	6,922	41,485	32,089
2045	7,636	6,926	41,976	32,032
2046	7,686	6,936	42,561	32,029
2047	7,741	6,948	43,180	32,038
2048	7,783	6,949	43,824	32,101
2049	7,822	6,954	44,286	32,053
2050	7,869	6,996	44,883	32,486

Table 2.14-21 Demand Forecast with EV

Annual Peak			Demand Forecast with EV				
				Summer		Winter	
Year	Month		Year	MW	Month	MW	Month
2021	7		2021	6,856	7	5,206	12
2022	7		2022	6,973	7	5,349	12
2023	7		2023	6,936	7	5,349	12
2024	7		2024	6,944	7	5,344	12
2025	7		2025	6,960	7	5,373	12
2026	7		2026	6,799	7	5,099	12
2027	7		2027	6,855	7	5,134	12
2028	7		2028	6,896	7	5,155	12
2029	7		2029	6,945	7	5,215	12
2030	7		2030	7,012	7	5,267	12
2031	7		2031	7,076	7	5,312	12
2032	7		2032	7,148	7	5,304	12
2033	7		2033	7,196	7	5,363	12
2034	7		2034	7,251	7	5,407	12
2035	7		2035	7,319	7	5,467	12
2036	7		2036	7,379	7	5,509	12
2037	7		2037	7,437	7	5,579	12
2038	7		2038	7,500	7	5,636	12
2039	7		2039	7,573	7	5,693	12
2040	7		2040	7,631	7	5,725	12
2041	7		2041	7,679	7	5,776	12
2042	7		2042	7,731	7	5,812	12
2043	7		2043	7,555	7	5,531	12
2044	7		2044	7,593	7	5,545	12
2045	7		2045	7,636	7	5,592	12
2046	7		2046	7,686	7	5,631	12
2047	7		2047	7,741	7	5,667	12
2048	7		2048	7,783	7	5,680	12
2049	7		2049	7,822	7	5,720	12
2050	7		2050	7,869	7	5,754	12

Table 2.14-22 EV Forecast

EV Forecast		
Year	Demand (MW)	Energy (GWh)
2021	10	67
2022	11	137
2023	21	267
2024	34	438
2025	46	603
2026	59	769
2027	73	964
2028	91	1,214
2029	115	1,534
2030	144	1,937
2031	177	2,397
2032	212	2,879
2033	248	3,381
2034	286	3,902
2035	324	4,434
2036	362	4,973
2037	401	5,518
2038	440	6,069
2039	479	6,627
2040	519	7,202
2041	560	7,786
2042	600	8,359
2043	636	8,886
2044	671	9,397
2045	709	9,944
2046	750	10,532
2047	793	11,141
2048	834	11,723
2049	868	12,232
2050	873	12,397

**Demand values are coincident to system peak.*

Table 2.14-23 Distributed Solar Forecast (Nameplate MW)

Distributed Solar (Nameplate MW)			
Year	Behind the Meter	Community Gardens	Total
2021	496	123	619
2022	561	206	768
2023	629	296	925
2024	705	385	1,089
2025	783	473	1,256
2026	865	561	1,426
2027	953	649	1,602
2028	1,047	736	1,782
2029	1,145	822	1,968
2030	1,250	909	2,159
2031	1,360	994	2,354
2032	1,475	1,080	2,555
2033	1,596	1,164	2,759
2034	1,721	1,245	2,966
2035	1,851	1,324	3,175
2036	1,985	1,405	3,390
2037	2,123	1,482	3,605
2038	2,264	1,552	3,816
2039	2,407	1,613	4,020
2040	2,552	1,676	4,228
2041	2,697	1,718	4,415
2042	2,842	1,724	4,566
2043	2,987	1,724	4,711
2044	3,130	1,724	4,854
2045	3,270	1,724	4,994
2046	3,407	1,724	5,131
2047	3,541	1,724	5,265
2048	3,670	1,724	5,394
2049	3,794	1,724	5,518
2050	3,914	1,724	5,638

**Demand values are July numbers.*

Table 2.14-24 Distributed Solar (Firm MW)

Distributed Solar (Firm MW)			
Year	Behind the Meter	Community Gardens	Total
2021	172	74	246
2022	195	123	319
2023	119	119	238
2024	122	122	244
2025	132	145	277
2026	143	167	310
2027	154	188	342
2028	165	208	373
2029	176	227	403
2030	188	244	432
2031	199	261	459
2032	210	276	486
2033	221	289	510
2034	231	301	532
2035	241	311	552
2036	250	321	571
2037	259	328	587
2038	266	333	599
2039	273	333	606
2040	278	332	611
2041	283	336	618
2042	286	340	626
2043	288	344	632
2044	289	347	636
2045	289	349	638
2046	287	350	637
2047	285	350	635
2048	282	349	631
2049	278	348	626
2050	273	345	619

**Demand values are coincident to summer system peak.*

Roadmap[38] Load Forecast

The forecasts shown do not include the impact of DG solar, as DG solar is modeled as a resource, not a load modifier.

[38] As discussed in Section 2.2, the Company's high scenario is referred to as the Roadmap scenario.

Table 2.14-25 Demand and Energy Forecast (Roadmap)[39]

Demand and Energy Forecast				
	Demand (MW)		Energy (GWh)	
Year	Forecast with EV/BE	Forecast without EV/BE	Forecast with EV/BE	Forecast without EV/BE
2021	6,875	6,856	33,188	33,010
2022	7,002	6,973	33,352	32,929
2023	6,996	6,951	33,819	33,151
2024	7,042	6,978	34,702	33,766
2025	7,120	7,031	35,452	34,170
2026	7,023	6,906	35,421	33,737
2027	7,133	6,986	36,234	34,131
2028	7,237	7,063	37,181	34,685
2029	7,328	7,130	37,951	35,104
2030	7,441	7,219	38,826	35,627
2031	7,558	7,306	39,883	36,178
2032	7,697	7,413	41,162	36,895
2033	7,798	7,478	42,351	37,462
2034	7,917	7,558	43,695	38,118
2035	8,067	7,665	45,238	38,899
2036	8,224	7,774	46,972	39,805
2037	8,363	7,862	48,575	40,516
2038	8,519	7,963	50,333	41,313
2039	8,686	8,069	52,122	42,069
2040	8,840	8,159	53,976	42,823
2041	8,962	5,659	54,858	43,379
2042	9,005	5,585	55,778	44,002
2043	8,855	5,422	55,382	43,298
2044	9,195	5,529	56,346	43,969
2045	9,419	5,639	57,071	44,466
2046	9,702	5,815	57,839	45,091
2047	9,795	5,794	58,623	45,762
2048	9,690	5,682	59,516	46,520
2049	9,882	5,751	60,181	46,991
2050	10,001	5,820	60,984	47,619

[39] The decrease in peak demand exclusive of EV demand beginning in 2041 reflects the shift to a winter peaking system.

Table 2.14-26 Demand Forecast (Roadmap) with EV

Annual Peak			Demand Forecast with EV/BE				
				Summer		Winter	
Year	Month		Year	MW	Month	MW	Month
2021	7		2021	6,875	7	5,255	12
2022	7		2022	7,002	7	5,404	12
2023	7		2023	6,996	7	5,434	12
2024	7		2024	7,042	7	5,484	12
2025	7		2025	7,120	7	5,581	12
2026	7		2026	7,023	7	5,359	12
2027	7		2027	7,133	7	5,458	12
2028	7		2028	7,237	7	5,542	12
2029	7		2029	7,328	7	5,717	12
2030	7		2030	7,441	7	5,805	12
2031	7		2031	7,558	7	5,937	12
2032	7		2032	7,697	7	6,016	12
2033	7		2033	7,798	7	6,246	12
2034	7		2034	7,917	7	6,432	12
2035	7		2035	8,067	7	6,882	12
2036	7		2036	8,224	7	6,989	12
2037	7		2037	8,363	7	7,298	1
2038	7		2038	8,519	7	7,766	1
2039	7		2039	8,686	7	8,202	12
2040	7		2040	8,840	7	8,799	12
2041	12		2041	8,909	7	8,962	12
2042	12		2042	8,989	7	9,005	12
2043	1		2043	8,843	7	8,855	1
2044	12		2044	8,919	7	9,195	12
2045	12		2045	8,973	7	9,419	12
2046	12		2046	9,039	7	9,702	12
2047	12		2047	9,111	7	9,795	12
2048	1		2048	9,181	7	9,690	1
2049	1		2049	9,229	7	9,882	1
2050	1		2050	9,341	7	10,001	1

Table 2.14-27 EV and Beneficial Electrification Forecast[40]

EV and BE Forecast		
Year	**Demand (MW)**	**Energy (GWh)**
2021	19	178
2022	29	423
2023	46	668
2024	64	936
2025	89	1,282
2026	117	1,684
2027	147	2,104
2028	174	2,496
2029	198	2,847
2030	222	3,200
2031	252	3,706
2032	284	4,268
2033	320	4,889
2034	359	5,577
2035	402	6,340
2036	450	7,167
2037	501	8,059
2038	557	9,021
2039	617	10,053
2040	681	11,153
2041	3,303	11,478
2042	3,420	11,777
2043	3,433	12,084
2044	3,666	12,377
2045	3,780	12,605
2046	3,887	12,747
2047	4,001	12,861
2048	4,008	12,996
2049	4,131	13,189
2050	4,181	13,365

** Demand values are coincident to system peak.*

[40] The significant increase in demand beginning in 2041 coincides with the shift to a winter peaking system under this forecast.

Market Purchases and Sales Carbon Rate

In order to estimate emissions rates associated with market purchases, the Company assumes an annual average carbon emissions pounds/MWh rate, as shown in the table below. These estimates are the same as used in the Air Quality Control Commission ("AQCC") CEP verification workbook developed through the collaborative process coordinated by the AQCC.

Table 2.14-28 Carbon Dioxide Cap

CO2 Ton Cap		
Year	ERP	CEP
2021	-	-
2022	-	-
2023	-	-
2024	-	-
2025	-	-
2026	11,671,259	11,671,259
2027	11,671,259	11,671,259
2028	11,671,259	11,671,259
2029	11,671,259	11,671,259
2030	11,671,259	5,486,746
2031	11,224,864	5,349,577
2032	10,778,470	5,212,408
2033	10,332,076	5,075,240
2034	9,885,682	4,938,071
2035	9,439,287	4,800,902
2036	8,992,893	4,663,734
2037	8,546,499	4,526,565
2038	8,100,104	4,389,396
2039	7,653,710	4,252,228
2040	7,207,316	4,115,059
2041	6,486,584	3,703,553
2042	5,765,853	3,292,047
2043	5,045,121	2,880,541
2044	4,324,389	2,469,036
2045	3,603,658	2,057,530
2046	2,882,926	1,646,024
2047	2,162,195	1,234,518
2048	1,441,463	823,012
2049	720,732	411,506
2050	-	-

For market sales, the carbon tons and costs are deducted from the Company's emissions using the annual average of the system's carbon intensity on a scenario-by-scenario and year-by-year basis in post-processing.

Table 2.14-29 Market Purchase CO_2 Rate

Market Purchase CO2 Rate															
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
lbs/MWh	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450
	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
lbs/MWh	450	450	450	450	450	405	360	315	270	225	180	135	90	45	0

Generic Resources Cost and Performance

A "generic resource" means the representation of a potential new supply-side utility resource for benchmarking or modeling purposes that embodies the estimated cost and performance of the represented technology without regard to a specific site location. A generic resource is generally represented by: capacity (nameplate and summer rating or incremental capacity credit); capital and fixed O&M costs; transmission interconnection and grid upgrade costs; variable O&M costs (fuel and heat rates); book (useful) life; ramp rates and production curves; forced outage rates; typical annual maintenance requirements; emission rates; and indicative pricing (levelized costs).[41]

Generic resources serve multiple purposes in the 2021 ERP:

- Generic solar, wind, 4-hour duration battery storage, and gas-fired thermal resources were available to the EnCompass model when creating Phase I alternative plans both within the RAP and post-RAP periods, and
- Generic resources are used in the Benchmarking exercise as described in Section 2.5.

For portfolio selection in the Phase II competitive acquisition, generic resources are replaced with costs and performances of actual proposed projects.

Gas-Fired Thermal Resource Generics

Gas-fired thermal resource generics include: (1) a large-scale combustion turbine, (2) a large-scale 2x1 combined-cycle, (3) a small aeroderivative combustion turbine, and (4) a small reciprocating plant. The cost and performance specifications for the four thermal generics shown in Table 2.14-30 were provided by the Company's Energy

[41] Grid upgrade costs are not included in the generic costs presented; grid upgrade costs are site-specific.

Supply engineers based on values provided by its vendors. Annual fixed costs shown in $/kW-mo terms in Table 2.14-31 for the four generics were calculated within the EnCompass model.

4-Hour Duration Battery Storage Generic

Generic costs and performance for a 4-hour duration storage device were obtained from the 2020 NREL Annual Technology Baseline ("ATB").[42] The ATB represents cost and performance for battery storage in the form of a 4-hour, utility-scale, lithium-ion battery system with a 15-year assumed life. In order to create a 30-year generic battery, the Company assumed that the second 15-year period would be built as a "replacement" at the costs that the NREL ATB assumes for a project with an in-service year 15 years after the generic project's assumed in-service year. The ATB assumes an 85% round-trip efficiency. Levelized fixed costs based on in-service year data from the ATB are presented in Table 2.14-32. For purposes of Phase I modeling, the battery generic was represented using a 50 MW size/block and an assumed 365-round trip cycles per year.

Wind Generic

Generic costs for a 200 MW land-based wind generic were obtained from the 2020 NREL ATB. For purposes of modeling, the wind generic was represented using a 50 MW size/block. The Company selected data for a Class 3 wind resource and a Moderate Technology Scenario. Cost and performance values are shown in Table 2.14-30 consistent with how results are presented in the ATB; costs in the Table are levelized costs based on the in-service year over a 30-yearbook life. For example, a generic wind project with an in-service year of 2025 would have a 30-year levelized cost of $22.30/MWh. The following adjustments were made to the base ATB model:

- 30-year Capital Recovery Factor and Market Factors Financial assumptions were selected,
- Annual NCF was set to 50% for all years,
- Inflation was set to 2.0% per year,
- Tax rates were set to match combined Federal and Colorado rates,
- Given changes to federal tax credits approved following the release of the 2020 ATB, projects with in-service dates of 2025 were modeled with a 60% PTC and Debt Fraction, WACC Nominal and WACC Real values were set to 2024 values.

Solar Generic

Generic costs for a 100 MW PV utility solar generic were obtained from the 2020 NREL ATB. For purposes of modeling, the solar generic was represented using a 50 MW size/block. The Company selected data for a Moderate Technology Scenario. Cost and performance values are shown in Table 2.14-30 consistent with how results are

[42] Available at: https://atb.nrel.gov/electricity/2020/data.php.

presented in the ATB; costs in the Table are levelized costs based on the in-service year over a 30-yearbook life. For example, a generic solar project with an in-service year of 2025 would have a 30-year levelized cost of $26.00/MWh. The following adjustments were made to the base ATB model:

- Annual NCF was adjusted to match a Colorado resource (30% with annual degradation),
- Inflation was set to 2.0% per year,
- Tax rates were set to match combined Federal and Colorado rates,
- Given changes to federal tax credits approved following the release of the 2020 ATB, projects with in-service dates of 2024 and 2025 were modeled with: (1) a 26% ITC, and (2) Debt Fraction, WACC Nominal and WACC Real set to 2023 values.

Table 2.14-30 Generic Dispatchable Resource Cost and Performance

Resource	Generic CT	Generic CC (2x1)	Generic Aeroderiative	Generic Reciprocating
Technology	7F.05	7F.05	PW FT4000	6-Wärtsilä 18V50SG
Cooling Type	Dry	Wet	Dry	Dry
Book life	40	40	40	40
Winter Peak Capacity (MW)	196	672	57	100
Summer Peak Capacity (MW)	175	657	51	100
Other Months Capacity (MW)	193	671	55	100
Duct Burners		Fired		
Capital Cost ($000) 2018$	$119,100	$545,100	$74,800	$131,100
Transmission Adder ($000) 2018$	$18,800	$161,500	$5,500	$9,600
Total Capital ($000) 2018$	$137,900	$706,600	$80,300	$140,700
Capital Cost ($/kW) 2018$ (Summer MW)	$788	$1,075	$1,575	$1,407
Firm Fuel Costs (2018 $/kW-yr; Summer MW)	$1.12	$1.02	$1.12	$1.00
Ongoing Capital Expenditures ($000-yr) 2018$	$1,160	$5,210	$690	$540
Fixed O&M Cost ($000/yr) 2018$	$660	$4,670	$300	$800
Variable O&M Cost ($/MWh) 2018$	$1.46	$1.95	$1.66	$9.32
Summer Heat Rate w/ duct burners (btu/kWh)		6,705		
Summer Heat Rate 100% Loading (btu/kWh)	10,015	6,534	9,509	8,400
Summer Heat Rate 75% Loading (btu/kWh)	10,588	6,725	10,300	-
Summer Heat Rate 50% Loading (btu/kWh)	12,532	7,259	11,530	9,420
Summer Heat Rate 25% Loading (btu/kWh)	13,448	7,460	-	-
Winter Heat Rate w/ duct burners (btu/kWh)		6,697		
Winter Heat Rate 100% Loading (btu/kWh)	9,768	6,545	9,199	8,320
Winter Heat Rate 75% Loading (btu/kWh)	10,223	6,682	9,608	-
Winter Heat Rate 50% Loading (btu/kWh)	12,042	7,150	11,042	9,330
Winter Heat Rate 25% Loading (btu/kWh)	12,882	7,350		-
Other Months Heat Rate w/ duct burners (btu/kWh)		6,669		
Other Months Heat Rate 100% Loading (btu/kWh)	9,820	6,510	9,268	8,320
Other Months Heat Rate 75% Loading (btu/kWh)	10,257	6,647	9,665	-
Other Months Heat Rate 50% Loading (btu/kWh)	12,031	7,117	11,076	9,330
Other Months Heat Rate 25% Loading (btu/kWh)	12,844	7,309	-	-
Forced Outage Rate	4.0%	4.0%	4.0%	4.0%
Maintenance (weeks/yr)	2	3	1	1
Lowest stable operating Point (% of nameplate)	46%	20%	49%	2%
Normal ramp rate (MW/Min)	25	50	31	144
Water use, Consumptive (gallons/MWh)	22	250	22	1
CO2 Emissions (lbs/MMBtu)	119	119	119	119
SO2 Emissions (lbs/MWh)	0.0064	0.0039	0.0066	0.0066
NOx Emissions (lbs/MWh)	0.4291	0.0915	0.4291	0.4291
PM10 Emissions (lbs/MWh)	0.0402	0.0300	0.0402	0.0402
Mercury Emissions (lbs/MMWh)	0.0000	0.0000	0.0000	0.0000

Table 2.14-31 Annual Fixed Costs of Dispatchable Generic Resources

	Annual Fixed Costs (nominal $/kW-mo) [1]			
Year	Generic CT	Generic CC (2x1)	Generic Aeroderiative	Generic Reciprocating
2021	$ 6.85	$ 8.89	$ 12.47	$ 10.72
2022	6.96	9.04	12.70	10.92
2023	7.08	9.20	12.93	11.12
2024	7.20	9.37	13.17	11.32
2025	7.32	9.54	13.41	11.53
2026	7.45	9.71	13.66	11.74
2027	7.57	9.88	13.91	11.95
2028	7.70	10.06	14.16	12.17
2029	7.83	10.24	14.42	12.39
2030	7.97	10.42	14.69	12.62
2031	8.10	10.61	14.96	12.86
2032	8.24	10.80	15.24	13.09
2033	8.39	11.00	15.52	13.33
2034	8.53	11.20	15.81	13.58
2035	8.68	11.40	16.10	13.83
2036	8.83	11.61	16.40	14.09
2037	8.99	11.82	16.71	14.35
2038	9.14	12.03	17.02	14.62
2039	9.30	12.26	17.34	14.89
2040	9.47	12.48	17.66	15.17
2041	9.63	12.71	17.99	15.45
2042	9.80	12.94	18.33	15.74
2043	9.98	13.18	18.67	16.04
2044	10.15	13.42	19.03	16.34
2045	10.34	13.67	19.38	16.64
2046	10.52	13.93	19.75	16.96
2047	10.71	14.18	20.12	17.28
2048	10.90	14.45	20.50	17.60
2049	11.10	14.72	20.89	17.93
2050	11.29	14.99	21.28	18.27
2051	11.52	15.29	21.71	18.64
2052	11.75	15.60	22.14	19.01
2053	11.98	15.91	22.58	19.39
2054	12.22	16.23	23.03	19.78
2055	12.47	16.55	23.49	20.17

Notes

1) Total capacity costs are based on summer MW ratings and are inclusive of: initial and ongoing capex, FOM, firm fuel costs, and transmission interconnection and assumed delivery costs, where applicable.

2) No firm fuel or transmission delivery costs were assigned to battery storage generics.

Table 2.14-32 Generic Renewable and Energy Storage Resource Costs

	Capital Costs (nominal $/kW) [1]		Levelized Energy Costs (nominal $/MWh) [2]		Levelized Fixed Costs (nominal $/kW-mo) [3]
In-Service Year	Solar	Wind	Solar	Wind	4-Hour Duration Battery Storage
2021	$ 1,350	$ 1,500	$27.10	$19.50	$10.55
2022	1,320	1,510	26.60	22.40	10.19
2023	1,290	1,510	26.00	22.40	10.13
2024	1,260	1,520	26.70	22.30	10.14
2025	1,230	1,520	26.00	22.20	9.73
2026	1,200	1,520	28.50	30.10	11.04
2027	1,160	1,520	27.90	30.50	10.89
2028	1,120	1,520	27.30	30.80	10.73
2029	1,080	1,520	26.70	31.20	10.56
2030	1,040	1,510	25.90	31.50	10.39
2031	1,050	1,510	26.20	31.80	10.41
2032	1,060	1,500	26.50	32.10	10.43
2033	1,070	1,490	26.80	32.50	10.44
2034	1,080	1,510	27.10	32.80	10.44
2035	1,100	1,520	27.30	33.10	10.44
2036	1,110	1,530	27.60	33.50	10.55
2037	1,120	1,550	27.90	33.80	10.60
2038	1,130	1,560	28.20	34.10	10.64
2039	1,140	1,580	28.50	34.50	10.68
2040	1,150	1,590	28.80	34.80	10.71
2041	1,160	1,600	29.10	35.10	10.74
2042	1,180	1,620	29.40	35.50	10.76
2043	1,190	1,630	29.70	35.80	10.78
2044	1,200	1,650	29.90	36.10	10.78
2045	1,210	1,660	30.20	36.40	10.78
2046	1,220	1,670	30.50	36.80	10.77
2047	1,230	1,680	30.80	37.10	10.74
2048	1,250	1,700	31.10	37.40	10.71
2049	1,260	1,710	31.40	37.70	10.66
2050	1,270	1,720	31.70	38.00	10.60
2051	1,280	1,740	32.00	38.40	10.60
2052	1,290	1,750	32.30	38.70	10.60
2053	1,300	1,770	32.60	39.00	10.60
2054	1,320	1,780	32.80	39.30	10.60
2055	1,330	1,790	33.10	39.70	10.60

Notes

1) Capital costs are the NREL ATB Overnight Capital Costs inflated at 2%/yr from 2018 to the in-service year.

2) Levelized energy costs are the NREL ATB levelized energy costs calculated over the assumed book life inflated at 2%/yr from 2018 to the in-service year.

3) Levelized fixed costs are calculated from the NREL ATB capital costs (with an assumed 11% levelized fixed charge rate) and FOM costs, both inflated at 2%/yr from 2018 to the in-service year. The calculation also assumes that the battery qualifies for the currently existing federal ITC.

2.15 WATER RESOURCES

In this Section, the Company provides water resources information required by Rule 3604(h), including: (1) the annual water consumption for each of Public Service's existing generation resources; (2) the water intensity (in gallons per MWh) of the existing generating system as a whole; and (3) the projected water consumption for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its resource plan.

Use of Water in Electric Generation

Water is consumed during electric generation in a variety of ways:

1. Steam/water cycle. Steam generation is typically a closed-loop system, but boiler feed make-up water is required to replace minor losses.
2. Circulating water cooling. Circulating water is used to cool steam in the steam/water cycle. Circulating water is evaporatively-cooled in the cooling towers and reused until its water quality is no longer suitable. Blowdown rejected from the cooling tower is treated prior to discharge or stored and evaporated, depending on plant design. Cooling typically represents the vast majority of plant water usage and consumption.
3. Other usage. Relatively small volumes of water are used in a number of other important plant capacities, such as dust suppression, fire control, bottom ash removal, and emissions control.
4. Hydro-electric generation. Water consumed is through evaporation while stored in reservoirs at Public Service-owned hydropower facilities in Colorado.

Public Service's Water Consumption and Intensity

Table 2.15-1 shows the 2020 water consumption as well as average use for the Public Service system.

Figure 2.15-1 shows the water intensity for Public Service-owned generation stations and the relative proportion of water supplied through self-owned and contracted water supplies. Generally, self-supplied water is the least expensive and future costs are expected to remain stable, in accordance with O&M needs. Contracted water supply costs are anticipated to increase in line with regional water costs but afford plants the reliability and firm yields associated with larger municipal water purveyors. Table 2.15-2 shows annual consumptive water use and intensity by Public Service facility.

Table 2.15-1 2020 Water Use and Generation by Public Service Facility

Public Service Generating Station	**2020 Consumptive Water Use** (Acre-feet)	**Percent Consumptive Water Use** (As a %)	**2020 Net Generation** (NMWHRS)	**Water Intensity** (gal/ MWh)
Cherokee	3,027	75.1	3,744,662	256
Comanche	7,899	77.6	4,217,098	625
Fort Saint Vrain	2,121	66.7	3,716,079	186
Hayden (1)	4,261	100%	3,139,862	442
Pawnee(1)	4,823	100%	3,067,953	513
Rocky Mountain Energy Center	2,507	100%	3,039,709	263
Valmont (2)	1,331	0%	10,043	N/A
Hydros(3)	103	100%	31,269	1,073
Craig (Xcel Portion)(4)	917	100%	33,178	490
Alamosa*	0	N/A	13,018	N/A
Blue Spruce*	0	N/A	478,339	N/A
Ft. Lupton*	0	N/A	7,984	N/A
Fruita*	0	N/A	1,131	N/A
TOTALS	**30,989**		**21,500,325**	

(1) Hayden and Pawnee's raw water usage numbers reflect river pumping
(2) Raw water usage at Valmont is the amount of water attributed to diversions under the Valmont water rights
(3) Hydro water consumption from reservoir evaporation. Hydro net generation includes Ames, Georgetown, Salida, Shoshone, and Tacoma, but excludes Cabin Creek.
(4) Xcel Energy owns 9.7% of Craig Units 1&2
* Internal combustion engines and existing CT Turbine facilities require no water for generation using gas.

Figure 2.15-1 Water Intensity

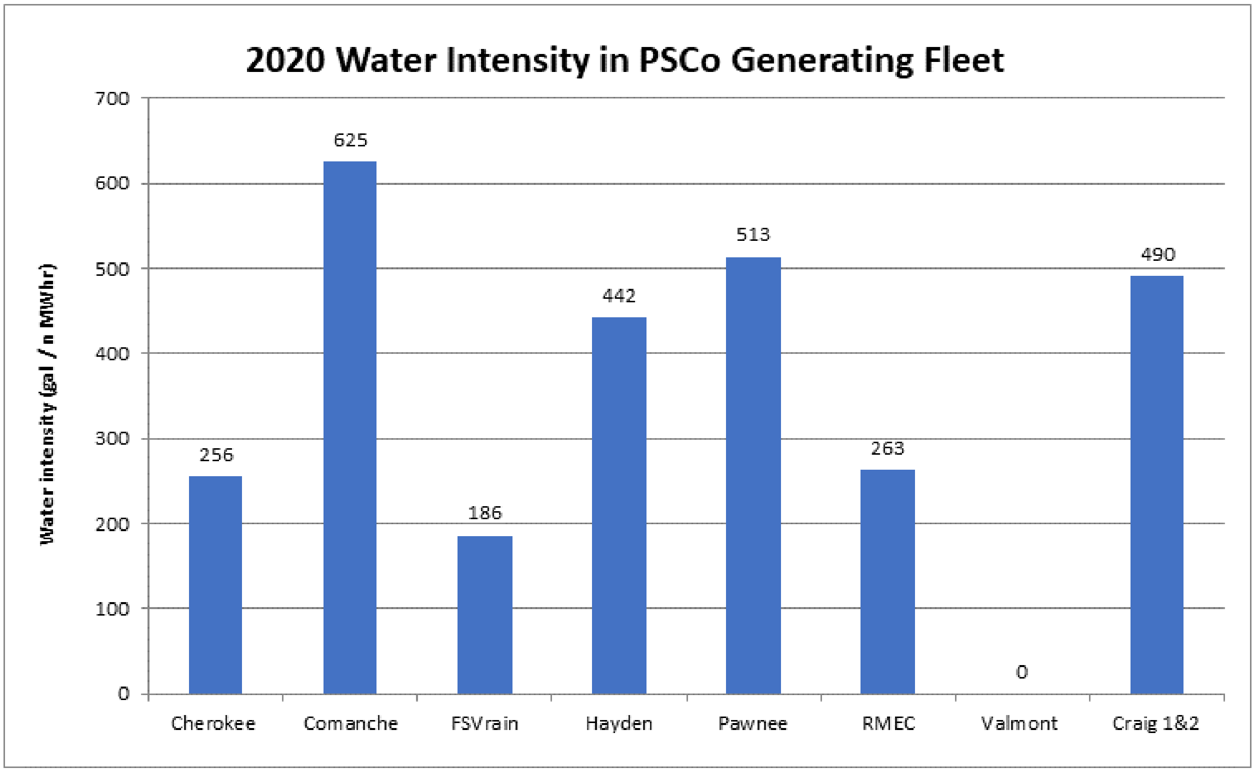


Table 2.15-2 Annual Consumptive Water Use and Intensity by Public Service Facility

IPP - Gas	Annual net generation (MWh)	Water consumption (gallons)	Water intensity (gallons/ MWh)
ARAPAHOE	207,688	82,582,000	398
BRUSH 2	25,392	12,831,000	505
BRUSH 4	89,481	52,917,000	591
BRUSH1&3	33,715	11,741,000	348
MANCHIEF	451,445	707,550	2
FOUNTAIN VALLEY	143,764	18,635,000	130
PLAINS END 1*	6,726	-	0
PLAINS END 2*	8,614	-	0
SPINDLE HILL*	427,387	-	0
WM RENEWABLE*	20,874	-	0
Total - IPP Gas	***1,415,087***	***179,413,550***	-
IPP - Wind		-	0
Twin Buttes Wind	265,763	-	0
Cedar Creek II, LLC	677,728	-	0
Cedar Creek Wind Energy, LLC	790,015	-	0
Cedar Point Wind, LLC	710,180	-	0
Colorado Green Holdings, LLC	247,878	-	0
EPRI	115	-	0
Golden West Power Partners, LLC	841,867	-	0
Sping Canyon Energy, LLC	182,052	-	0
Limon Wind III, LLC	812,020	-	0
Limon Wind II, LLC	611,204	-	0
Limon Wind, LLC	711,044	-	0
Logan Wind Energy, LLC	556,615	-	0
Northern Colorado Wind Energy I	401,230	-	0
Northern Colorado Wind Energy II	64,329	-	0
Peetz Table Wind Energy, LLC	671,745	-	0
Ridge Crest Wind Partners, LLC	71,721	-	0
Siemens Energy	174	-	0
Bronco Plains Wind, LLC	658,426	-	0
Mountain Breeze Wind	161,119	-	0
Total - IPP Wind	***8,435,223***	-	-

*Combustion turbine with no water use

	Annual net generation (MWh)	Water consumption (gallons)	Water intensity (gallons/ MWh)
IPP - Solar		-	0
Cogentrix of Alamosa	55,626	-	0
Comanche Solar PV, LLC	291,353	-	0
San Luis Solar, LLC	76,878	-	0
Solar Star Colorado III	125,372	-	0
Sun E Alamosa1, LLC	13,964	-	0
Sun Power/ Greater Sandhill	47,812	-	0
Titan Solar, LLC	101,876	-	0
Total - IPP Solar	***712,881***	-	-
IPP - Hydro		-	0
City of Boulder Betasso/Lakewood	23,398	-	0
Denver Water - Dillon	11,984	-	0
Denver Water - Foothills	6,088	-	0
Denver Water - Gross	17,902	-	0
Denver Water - Hillcrest	5,529	-	0
Denver Water - Roberts Tunnel	8,935	-	0
Denver Water - Strontia	7,179	-	0
Redlands Water and Power	7,617	-	0
Ute Hydro	1,347	-	0
Orchard Mesa	3,353	-	0
Grand Valley	3,353	-	0
Total - IPP Hydro	***96,685***	-	-

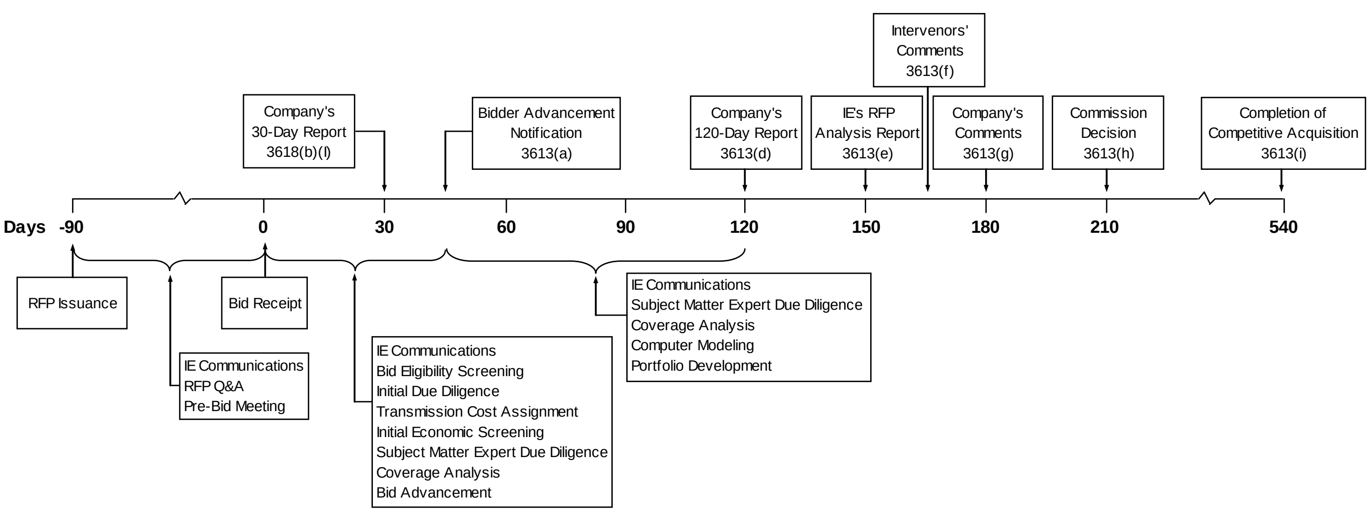
2.16 PHASE II RESOURCE ACQUISITION PLAN

In this Section, the Company describes its Phase II resource acquisition plan, bidding policy, and the competitive acquisition procedures it intends to use to obtain resources in Phase II of the ERP process as required by Rule 3611(g). Volume 3 of the Company's 2021 ERP & CEP contains the proposed RFPs the utility intends to use to solicit bids for energy and capacity resources to be acquired through the Phase II competitive acquisition process, the associated bid forms and model purchase agreements, as required by Rule 3604(i) and Rule 3616(a).

Company Activities Following the Release of an RFP

The Company anticipates issuing competitive solicitations approximately 90 days in advance of the bid receipt date. As filed in Volume 3 of this 2021 ERP, the Company is proposing three (3) distinct requests for proposal documents: (1) a Dispatchable Resources RFP, (2) a Renewable Resources RFP, and (3) a Company Ownership RFP. Official versions of the RFP documents (the RFP document, a model contracting agreement or model term sheet, and proposal submission forms) will be posted to an RFP webpage on the day of the RFP release. An indicative timeline of Phase II activities is shown in Figure 2.16-1.

Figure 2.16-1 Indicative Phase II Timeline



Rule 3616(d) requires the Company to provide potential bidders with a copy of the Commission's order or orders specifying the form of nondisclosure agreement necessary to obtain access to confidential and highly confidential modeling inputs and assumptions provided by the Company pursuant to Rule 3613(b). The nondisclosure agreement is included in the RFP bid submission forms and are included as part of the Volume 3 filing. Rule 3616(d) also requires the Company to provide potential bidders an explanation of the process by which disputes regarding inputs and assumptions to computer-based modeling will be addressed by the Commission pursuant to Rule 3613(b). This explanation can be found in Section 1.1 of the model RFP documents.

Rule 3616(e) directs the Company to require bidders to provide the contact information of a person designated to receive a notice pursuant to Rule 3613(a). Language directing the bidder to provide this information is on Form C of the model bid submission forms. Rule 3616(f) requires the Company to inform bidders that information for all bids submitted in response to the RFP will be made available to the public through posting of the bid information on the Company's website upon the completion of the competitive acquisition process pursuant to Rule 3613(k). This information can be found in Section 1.1 of the model RFP documents.

The Company anticipates that any pre-bid meeting would be held approximately three (3) weeks following the issuance of a competitive solicitation. In addition to a pre-bid meeting, the Company will directly respond to potential bidder questions submitted via email. Non-confidential Q&A versions of issues raised during any pre-bid meeting as well as from questions submitted via email will be posted to the Q&A document on an RFP webpage. The Independent Evaluator will be copied on all emails sent directly to potential bidders.

Bid Receipt and Generation Technology Categorization

The Company will request both hard copy and electronic versions of proposals; copies of bid submission materials will be provided to the Independent Evaluator and to Commission Staff. Upon receipt of bids, the Company will conduct an initial review to categorize the bid by its proposed generation source with bids employing similar technologies. Such an initial categorization simplifies downstream due diligence and economic evaluations and is necessary to comply with ERP Rule 3618(b)(I) regarding the 30-day report.

Bid Eligibility Screening and Initial Due Diligence

Once bids have been catalogued, the Company will conduct a review of each bid to ensure that the proposal meets the minimum eligibility requirements. Each of the three RFPs have slightly different minimum eligibility requirements corresponding to the different technologies or ownership structures targeted by the RFPs; specific details on the minimum bid eligibility requirements are laid out in the respective model RFP documents in Volume 3. The Company intends to notify all RFP respondents within 15 days of bid receipt as to the Company's bid eligibility evaluation.

At the time that the Company conducts its bid eligibility screening, it will also conduct an initial due diligence review of the bids. This initial due diligence review is intended to quickly identify any potential fatal flaws or conceptual misunderstandings as to the proposed project. To the extent the Company requires additional information from the bidder as a result of its initial due diligence, it will contact the bidder promptly and ensure that the Independent Evaluator receives a copy of the request for additional information as well as a copy of the bidder's reply.

Initial Economic Analysis and Screening

Assignment of Transmission Interconnection and Network Upgrade Costs

One of the bid eligibility requirements is that the project must function as a network resource; i.e., capacity and energy from the proposed generation project must be delivered to the Company's electric transmission or distribution system at a location such that the capacity and energy can then be delivered to the Company's customers. The Company will assign incremental transmission interconnection costs and/or network delivery costs to each bid, as appropriate. Transmission-associated capital costs will be converted to annual levelized costs utilizing a levelized fixed charge rate ("LFCR") of 8% for inclusion in the initial economic screening.

If the Company has received a certificate of public convenience and necessity to construct a transmission upgrade, the cost of the upgrade will not be included in the evaluation and costing of bids and/or bid portfolios that use those upgrades; provided, however, that sufficient transmission transfer capability exists on the transmission project specified in the CPCN after accounting for other generation projects.

For bids that: (1) utilize a transmission project for which a CPCN has been filed and is pending, or (2) utilize a Commission approved "bid-eligible planned transmission project" identified in the Phase I decision, transmission upgrade costs will not be included in the bids for purposes of determining advancement to computer-based modeling. In computer-based modeling, transmission upgrade costs will be included in the costing of the bids. At the completion of computer-based modeling, the total cost of the transmission upgrade will be included in any portfolio with a bid or bids that would utilize that transmission upgrade for portfolio costing and comparison purposes.

Existing resources from which the Company currently purchases capacity and energy will not be burdened with any incremental electrical transmission interconnection or network delivery costs provided that the Company currently has sufficient transmission capacity to deliver the entire generation to its load. For existing resources with inadequate transmission service, a projection of the purchase of sufficient transmission rights will be added to the bid.

Initial Economic Screening

Initial economic screening consists of calculating an “all-in” levelized energy cost (“LEC”) for energy-based bids (e.g., renewable generators or renewable hybrid generators) or, for dispatchable and standalone storage projects, an “all-in” levelized cost of capacity (“LCC”). LECs are calculated as the present value of the sum of the total costs and credits for each year of the proposed project’s term divided by the present value of the estimated annual energy streams. LCCs are calculated in a similar manner but the divisor is the level of capacity, not energy. Present values are calculated as of the project’s in-service year to avoid confusing the inherent value of delay with true differences in LEC or LCC. The Company will employ its after-tax WACC in the present value calculations.

The term “all-in” refers to the inclusion of costs and benefits associated with the project, e.g., renewable integration costs for solar and wind bids and renewable integration credits for storage bids. Projects that propose to interconnect at distribution voltages will be credited with avoided line losses in their LEC and LCC calculations. The result of this credit is that the LEC or LCC for a distribution-interconnected project will be lower than that for an identical, transmission-interconnected project by the avoided line loss assumption.

Other adjustments the Company may make to the LEC and LCC calculations include, but are not limited to:

- The Company’s final natural gas forecast,
- The Company’s estimates of fuel delivery costs on both an interruptible and a firm basis, where applicable,
- The Company’s estimates of any incremental transmission interconnection or network upgrade costs,
- Adjustments to estimated performance or pricing that result from the Company’s due diligence efforts and/or updated information received from the bidder.

No renewable energy credit (“REC”) value benefits will be credited to the LEC or LCC calculations for any generation projects.

Outside of these general observations, specific costs and benefits will be assessed to bids employing certain generation technologies as detailed below.

Stand-alone Storage LCC

In addition to proposed capacity payment rates, LCCs for stand-alone storage bids include an annual representation of proposed variable O&M costs and renewable energy credits. Variable O&M payment rates and renewable energy credits will be converted to a $/kW-mo metric by applying the annual throughput limit (MWh) proposed for the storage device. LCCs are converted to a generation capacity credit basis by dividing by the ELCC assigned to the project.

Renewable Hybrid Storage LEC and LCC

An LEC for a renewable hybrid storage bid will be calculated in a similar manner as that for a standalone solar or wind facility; however, the variable payment rate for the LEC calculation will be the Energy Payment Rate less the Battery Payment Rate proposed in the bid. An LCC for a renewable hybrid storage bid will be calculated by converting the Battery Payment Rate and renewable energy credits to a $/kW-mo metric by applying the annual throughput limit (MWh) proposed for the storage device. LCCs are converted to a generation capacity credit basis by dividing by the ELCC assigned to the project.

Dispatchable Generation LCC

In addition to proposed capacity payment rates, LCCs for dispatchable generation bids include an annual representation of proposed tolling payment costs and start charges. Tolling payments are calculated by converting the variable costs to fixed costs assuming an annual capacity factor and assuming an average annual heat rate with which to estimate fuel volumes and costs. Gas-fired, peaking resources will be screened with an assumption of a 5% annual capacity factor. Gas-fired, intermediate resources will be screened with an assumption of a 40% annual capacity factor. The average annual heat rate utilized in the LCC calculations will be the average of the seasonal full load heat rates (without supplemental capacity) supplied in the bid forms.

Start charges are included as annual costs in $/kW-mo, assuming a set number of hours that a unit will run at full output once started; full output is defined as the net capability of the unit without supplemental capacity; e.g., duct firing on a combined-cycle power plant. For peaking resources, the Company assumes a four (4) hour run time per unit. For intermediate resources, the Company assumes a twelve (12) hour run time per unit and that all CTs are started, e.g., two (2) turbines started for a 2x1 CC facility.

To the extent a project proposes to wheel capacity and energy across another utility's transmission system prior to delivery to the Company's system, estimated wheeling losses will be imposed against the full load heat rate which will effectively increase the variable cost component of the LCC. Such an adjustment is necessary since the heat rates are calculated at the generation unit (which resides on another utility's system), whereas the other components of the LCC are all based on capacity and energy delivered to the Company's system.

Subject Matter Expert Due Diligence

Subject matter experts typically include, but are not limited to, Company personnel from the following organizations:

- Transmission Access
- Generation Resource Planning
- Transmission Planning
- Natural Gas Planning
- Commercial Operations
- Purchased Power
- Credit/Risk
- Tax
- Accounting
- Environmental Permitting
- Energy Supply
- Siting and Land Rights
- Water Supply

Each department conducts its due diligence reviews in the manner they determine best. In the event that subject matter experts require additional information or clarification on certain aspects of a bid, those requests will be forwarded to the bidders on a coordinated basis. Each bid reviewed by each department will result in a written due diligence report with an indication as to the feasibility of the project's ability to meets its proposed in-service date with the selected technology and proposed performance levels.

The Company reserves the right to employ outside technical experts to review bids to the extent the Company believes such analyses are warranted to sufficiently review any proposal.

30 Day Bid Summary Report (ERP Rule 3618(b)(I))

Pursuant to ERP Rule 3618(b)(I), the Company will report to the Commission within 30 days of bid receipt on the following topics:

- Bidder identity,
- Number of bids received (total and by resource type),
- MW (total and by resource type),
- Description of prices (by resource type),
- Whether or not the Company believes it needs to implement its contingency plan.

Secondary Economic Screening

Any adjustments to bid information that impacts a bid's LEC or LCC following the completion of the subject matter experts' due diligence efforts will be incorporated into final levelized calculations. Based on the final LEC or LCC calculations, all bids utilizing similar technologies will be sorted by levelized price, and by proposed commercial operation date, size, and location within a specific ERZ or solar resource zone.

Selection of Bids for Computer Modeling

All bids from existing thermal generation resources currently under contract with the Company and all Company proposals will be passed through screening to portfolio development. Fuel-tolled thermal facilities will be selected for inclusion in computer modeling based on their LCC calculated with and without assumptions of incremental firm fuel supply costs. Pursuant to ERP Rule 3616(d) and contingent upon the existence of sufficient bids passing through bid eligibility and due diligence screening, the Company shall pass forward to the portfolio development phase a sufficient quantity of bids across the various generation resource types such that resource plans can be created that conform to the range of scenarios for assessing the costs and benefits from the potential acquisition of increasing amounts of renewable energy resources or Section 123 Resources as specified in the Commission's Phase I decision.

To the extent initial EnCompass modeling indicates that all bids of a specific generation resource type (e.g., all wind bids) passed to portfolio development appear in the least-cost portfolio(s), additional bids utilizing that generation resource type will be included in subsequent model runs. This iterative process will be followed until no incremental bids greater than 10 MW employing that generation resource type are selected in the least-cost portfolio. Bidders whose projects are passed forward to portfolio development will be notified of their project's advancement pursuant to ERP Rule 3613(a) and will be provided with the modeling inputs and assumptions for that project pursuant to ERP Rule 3613(b).

Bids for Generation between 100 kW and 10 MW[43]

In general, the following process will be employed to determine cost-effective bid-eligible proposals <10 MW:

1. Categorize bids by technology,
2. Categorize bids by size: >= 10 MW and < 10 MW,
3. Sort < 10 MW bids by all-in LEC and LCC,

[43] Depending upon the pool of proposed projects received in a Phase II competitive acquisition, the Company may need to adjust the specific MW cutoff for various technologies instead of the 10 MW proposed here. Such an adjustment would be done in consultation with the Independent Evaluator.

4. Review the least-cost portfolio determined by EnCompass from the Base Case run and determine the generation types selected in each portfolio,
5. For each included generation type, determine all bid-eligible proposals < 10 MW that have an all-in LEC or LCC less than the highest all-in LEC or LCC, respectively, for that generation type in the portfolio and include those projects in the final portfolios.

For example, assume that the most expensive solar bid included in a final portfolio has a $30/MWh LEC and, further, that solar bids <10 MW with the following all-in LEC were proposed:

Table 2.16-1 Illustrative All-In LEC for Eligible Solar Bids <10 MW

Bid #	LEC ($/MWh)	Size (MW)
1	$25	3
2	$22	1
3	$39	5
4	$32	5
5	$25	7

In this instance, the Company would include Bid numbers 1, 2, and 5 (totaling 11 MW) in the portfolio along with those proposals selected by EnCompass.

A final check will be made to ensure that the inclusion of all cost-effective proposals < 10 MW does not provide excess capacity credit to the portfolio through the RAP to such an extent that it could replace another source(s) of capacity selected through the EnCompass modeling. If it does, two additional EnCompass runs will be conducted to determine which is most cost-effective: (1) include all cost-effective generators <10 MW in the final portfolio, or (2) include all cost-effective generators <10 MW and exclude the other generator(s) that could potentially be displaced. The final portfolio would be the least-cost of these two runs assuming that both runs meet all reliability metrics.

To the extent the least-cost portfolio does not include a certain generation type (e.g., solar) but lower priced bids (based on all-in LEC or LCC) exist for similar generators <10 MW, an ad hoc EnCompass run including those generators would be conducted to see if the revenue requirements of the least-cost portfolio increases or decreases. If the revenue requirements decrease with the addition of the <10 MW generators, they would be included in the final portfolios.

For certain generation types (e.g., hydro or gas-fired micro-turbines) the Company would not typically expect to receive bids in excess of 10 MW. For such situations, the lowest all-in LEC or LCC proposals (up to a maximum of three per technology) would be advanced to computer modeling and portfolio development along with those bids >10 MW already selected. To the extent the EnCompass model selected all three of the lowest all-in LEC proposals and other proposals for the same technology were also received, then ad hoc EnCompass runs would be conducted to determine the cost-effectiveness of these other proposals.

Rule 3604(n) requires the Company to describe how energy storage systems smaller than 30 MW may be accommodated in the Phase II competitive solicitation process. The Company will evaluate energy storage project bids 10 MW and larger along with all other bids 10 MW and larger. Storage projects less than 10 MW will be evaluated according to the process described above.

Report to Advanced Bidders

Pursuant to ERP Rule 3613(a), 45 days after bids are received the Company is to email each bidder and indicate whether its bid has been advanced to computer modeling and portfolio development. For those bids not advanced, the Company is to provide the reason(s) why the project will not be evaluated further. For those bids advanced to computer modeling and portfolio development, the Company is to provide the modeling inputs and assumptions that reasonably relate to that potential resource or to the transmission of electricity from that facility to the Company.

The Company will meet these reporting procedures for proposals that are 10 MW and greater. However, given that proposals <10 MW will, in general, not be advanced to computer modeling and portfolio development during the initial phases of portfolio development, these proposals will not receive such notification at the 45-day mark. To the extent that proposals <10 MW are included in final portfolios after they have been created, bidders will be notified at that time.

Computer Modeling and Portfolio Development

EnCompass will be used in developing portfolios of proposals/bids that are advanced to this stage of the competitive acquisition. The modeling framework Public Service will employ in the Phase II portfolio analysis is the same as that used to develop alternative plans that are discussed in ERP Volume 1 with two exceptions: (1) actual bids are used to meet RAP needs instead of generic estimates, and (2) bids will be extended through the end of the modeling period to ensure the RAP portfolio firm capacity meets the PRM obligation through the end of the modeling and is not rejected by the model.

How to model bids that do not extend through the planning period has been vigorously discussed in past ERPs, and in the last ERP the Company presented two separate views of portfolios using what was termed the “Replacement Method” and “Annuity Method.” For this ERP, the Company is proposing minor modifications that incorporate positions taken by other parties in past ERPs with the objective of effectuating a fair evaluation of competing bids. The Company proposes to use one single unified method that closely resembles the previous annuity method where all bids are extended through the end of the Planning Period using an appropriate and relevant financial analysis methodology often called a "replacement chain" analysis.

In this method, to extend bids that do not extend to the end of the modeling period, the bid will be sequentially "repeated" as many times as is necessary, keeping all parameters of the bid equivalent from both a financial and operational perspective. For operational characteristics, the exact same specifications of the bid[44] will be repeated using the same pattern (if it varies by year) as the original bid. As an example, for a sample 15-year bid, year 16 will have the specifications of year 1, year 17 will have year 2, etc.

All financial parameters, such as fixed or variable PPA payments, will be repeated so as to be equivalent to the bid proposal's costs throughout its term. In practice, the bid costs that are supplied in nominal dollars will first be converted to levelized equivalent fixed or variable costs using the Company's WACC. Then the levelized value will be escalated using the assumption for general inflation (2%) to the start of the repeat period and applied for the same number of years as the bid term. If a second "repeat" period is then needed (i.e. two times the bid term still does not extend through the modeling period), a third (or however many are necessary) repeat will be constructed in the same manner.

Company proposals will include the same costs and benefits as those applied in the initial economic screening of bids described earlier in this section. Company proposals and BOTs will be modeled using traditional capital revenue requirements when reporting annual total system costs. Since the useful lives of Company self-build proposals typically will extend through the end of the Planning period, generally no assumptions need be made on how to extend the lives of Company proposals. However, in the event a Company proposal does need to be backfilled, it will be done in the same manner as the bids. Just as with PPAs, the actual annual costs of the bid will be used for the bid period, and any extension will use the levelized cost escalated to the repeat year(s).

This extension process for bids is not in any way intended to represent "re-contracting" or any specific assumption regarding what resources will be chosen in the future years after the bid expires or what prices they will be offered at. It is simply a financial analysis methodology used to evaluate competing projects/proposals with unequal lives. In financial literature it is often referred to as the "replacement chain" approach. Ideally this approach would have enough replacements made to evaluate all the projects on a least common multiple of years (for example a 20-year bid and a 25-year bid would be evaluated over a 100-year period with 5 and 4 repetitions, respectively). However, this

[44] Such as capacity factor, nameplate capacity and generation profile for renewable bids, and heat rate and forced outage rate for dispatchable bids.

is not practical in computer modeling given the possibility of widely disparate lives leading to extremely long study periods (as in the given example in the previous sentence), nor is it consistent with Commission resource planning rules which require that NPV be calculated over a Planning Period of determinate length. Additionally, given that the economics of the portfolios are primarily evaluated on the basis of NPV, impacts beyond the modeling period have only small impacts due to the time value of money/discount rate, and there is little precision lost by cutting off all values past the modeling period.

Development of Bid Portfolios

As discussed earlier, in the computer modeling of all bid portfolios, Public Service will employ a similar modeling convention as that approved by the Commission in Proceeding Nos. 07A-447E and 11A-869E. All generic resources added in years beyond the RAP (2024-2054) in the base capacity expansion model developed for Phase II modeling that incorporates all the approved updates and changes the Commission orders in its Phase I order, will be locked down in the EnCompass model. Note that the term “locked down” refers to the fact that a generic resource is hardwired into the EnCompass model to begin its operating life in a specific year as opposed to being modeled in a fashion where it has a floating in-service date that is ultimately selected by the model based on economics. All generic resources “locked down” in the model will still be capable of being economically dispatched with the rest of the fleet to meet customer load in a least-cost manner with the exception of generation such as wind and solar PV, which are not capable of being dispatched. In 2021 modeling, unlike previous years, these locked down resources include all generic resources, whether gas, wind, solar or storage. Figure 2.9-2 shows a graphical depiction of the generic resources that are locked down in the modeling.

Figure 2.16-2 Depiction of EnCompass Model with Locked-down Resources

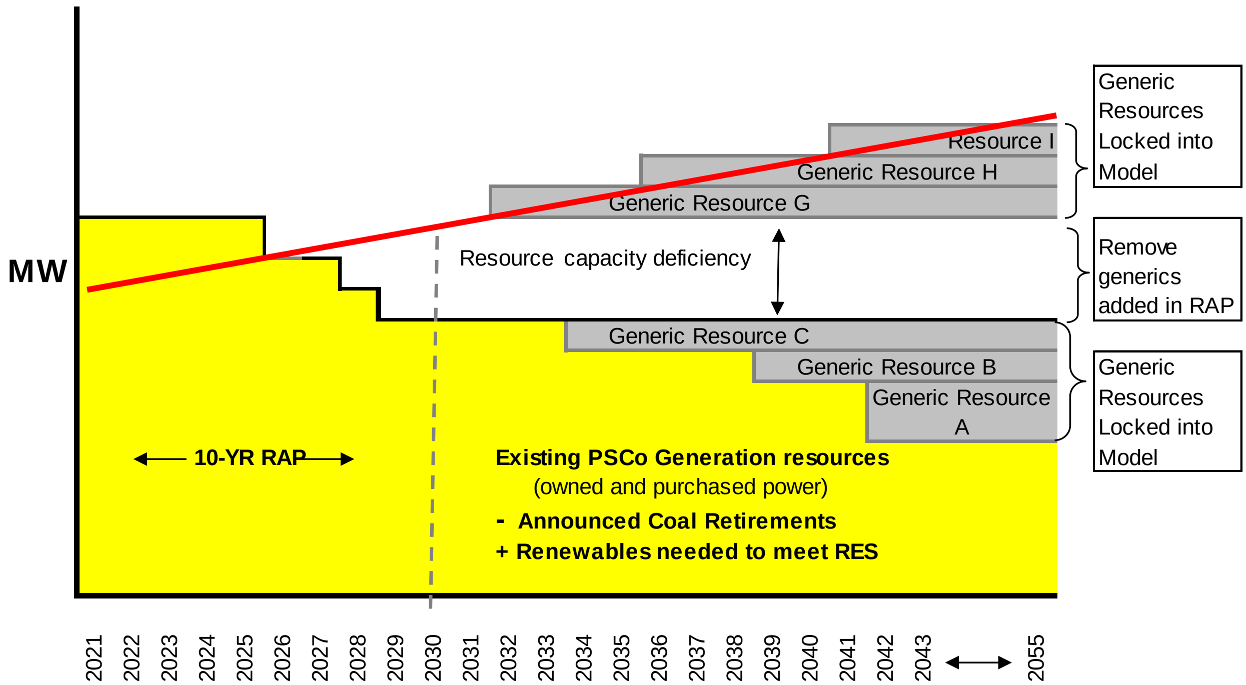
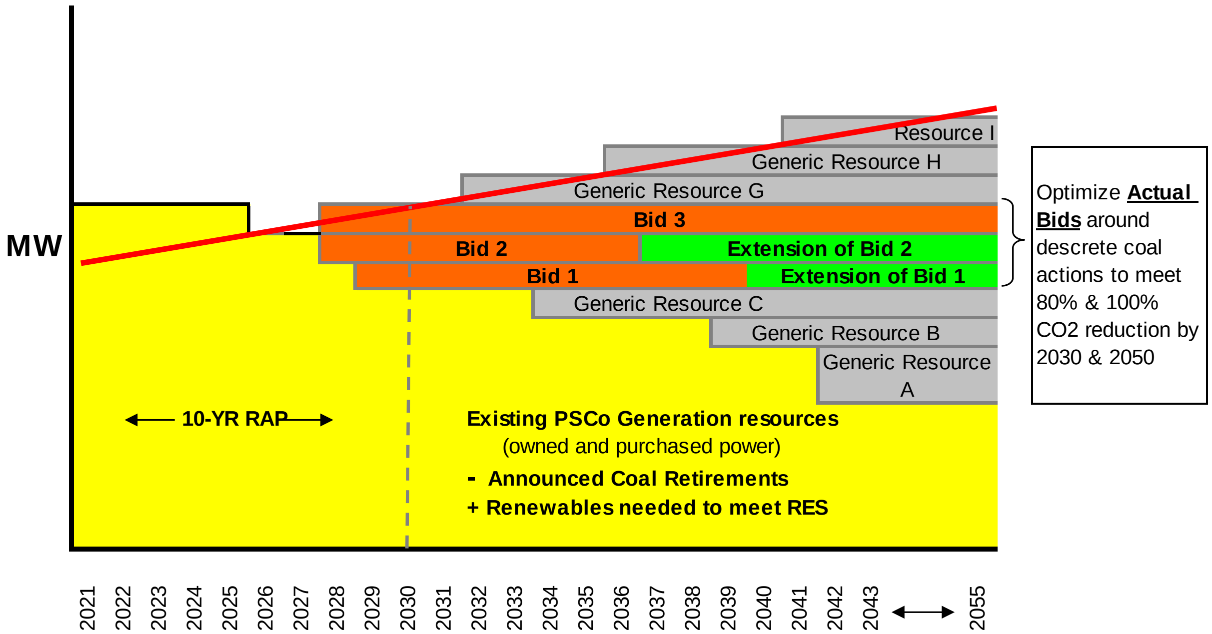


Figure 2.16-3 shows an example of how the bids will be extended (as necessary) to completely fill the gap created by removing the generic resources in the RAP. In this figure, Bid 3 has a term that extends to the end of the modeling period, so stands on its own. Bids 1 and 2 are shorter and are extended using the methodology for PPA and Company bids as discussed above. Due to the discrete size of the RAP generics, the set of removed resources will most likely result in a larger "hole" than the 2030 resource need identified in the L&R. In this likely event, a generic capacity-only purchase will be inserted in the years of the RAP to make the perceived "need" seen by the model exactly match the need determined using the approved L&R.

Figure 2.16-3 Illustration of a Portfolio of Bids and Company Proposals



Portfolio ELCC Review

The ELCC study documented in Attachment KLS-2 showed that the level of ELCC calculated for portfolios of resources can differ from the sum of the standalone ELCC values. This difference is impacted by the technology mix, location, and penetration of the various renewable generation and storage resources in the portfolio. As the initial creation of bid portfolios within EnCompass is conducted using standalone ELCC values, a "back end" portfolio ELCC review will be conducted to ensure that the selected portfolios meet forecasted load and planning reserve margins without significant capacity overbuild. This portfolio ELCC review would be conducted prior to any other post-EnCompass modeling reliability checks.[45]

Development of Sub-Optimal Bid Portfolios

The nature of mixed integer programs like EnCompass is that they converge internally to a single solution and do not explicitly save or generate "alternative" plans. The simplest way to generate alternative versions is to manually force certain portfolio parameters and rerun the model. The EnCompass software includes functionality to do

[45] Other reliability checks could include, but are not limited to, winter/firm fuel evaluations and intra-day fuel delivery evaluations.

this to a limited extent – there is a setting to produce multiple plans that are "different" through a given year (in Phase II, a setting of 2030 would be likely – thereby producing multiple different plans that are unique through 2030). The Company has not used this feature as of yet, and there is not an easy way to test it without having a large bid portfolio to select from. With only a limited selection of generics, the plans are not very informative.

An alternate approach is to manually force in (or remove) certain bids from the optimization and rerun the model, thereby creating portfolios that either specifically have or do not have the selected resources. Such a methodology can also be used to investigate the impacts of geographically diverse portfolios if the single solution portfolio does not include such geographic diversity.

One last approach is to manually force certain portfolio characteristics on the model, such as "at least 1,000 MW solar", or "no more than 1,000 MW wind", for example.

The Company intends to test all of these alternative approaches upon completion of the computer representation of the bids and will ensure a wide variety of alternative portfolios are presented in the 120-Day Report for Commission consideration.

Selection of Bid Portfolios for Sensitivity Analysis

A set of portfolios utilizing a range of technologies to meet the RAP needs will be selected for additional analyses involving an assessment of input assumption sensitivity analyses. A sufficient number of portfolios will be selected for these additional analyses to ensure a diverse set of generation technologies and locations are represented. The Company will use planning period PVRR (calculated using base/starting assumptions) as a key metric in determining the number of portfolios to advance.

Input assumption sensitivities would include:

- High and low gas price assumptions
- CO_2 proxy price (SCC and $0) assumptions

As was done in the analysis of the baseline case and alternative plans, the mix of proposals used to meet the RAP needs as well as the generic resources included beyond the RAP in each portfolio will be fixed or locked down when the portfolio PVRRs are recalculated under each sensitivity. This will ensure that cost differences between portfolios will be the result of differences in the factors being studied in the sensitivity analyses and not due to changes in the mix of resources beyond the RAP.

RESA Impact Analysis of Portfolios

Portfolios advanced to sensitivity analysis will also be analyzed to estimate their impact on the RESA. An abbreviated analysis will be employed to develop these estimates in which the annual additional costs or benefits will be estimated for each portfolio that result from renewable resources in the RAP. These additional costs or benefits will be added to or subtracted from the RESA impacts for the least-cost portfolio.

Rule 3616(c) on Best Value Employment Metrics

Section 40-2-129, C.R.S. now requires the Company to obtain from bidders and provide to the Commission information relating to best value employment metrics ("BVEM") for each bid resource, 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.

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.

Public Service and RMELC/CBCTC aligned on the fundamental need to obtain better, more thorough BVEM data from bidders through the competitive solicitation process. The problem regarding BVEM has been the lack of robust and detailed BVEM information from bidders. The generally scant information that has been provided by bidders in recent resource solicitations has limited the Commission's ability to consider the information in any sort of meaningful way. Independent power producers ("IPPs") have continued to argue that they are not in a position to provide detailed BVEM information at the time of bid submittal, while labor organizations continue to argue the BVEM information that is provided is not sufficient for the Commission to make resource acquisition decisions. This has been particularly challenging for the Company, as the criticism shifts to the utility when the BVEM information that the Company can only solicit from bidders is considered inadequate by labor organizations and the Commission itself.

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. 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 Project Labor Agreement ("PLA") is utilized (similar to the contracting structures that the Company has used and advanced in its Community Resiliency Initiative, EV Infrastructure, and Company-Owned Community Solar Garden aspect of its last RES Plan proceeding).

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.[46] 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 <u>will be required</u> and that bidders should know that this information <u>is necessary for their bids to be accepted</u>. Additionally, the Commission stated that it expects the Company to include the more detailed BVEM requirements in its RFP documents. Accordingly, the RFP documents contained in Volume 3 state that the Company can and will disqualify bids that provide insufficient BVEM as part of their bid packages.

The more detailed BVEM information requirements are reflected in Proposed Rule 3613 and reproduced below for reference. This additional language provides further detailed guidance to prospective bidders to assist them with providing detailed and robust BVEM information.

<u>Proposed Rule 3613: Best Value Employment Metrics</u>

Best value employment metric information regarding each proposed new utility resource shall include the following information.

(a) The availability of training programs, including training through apprenticeship programs registered with the United States Department of Labor, Office of Apprenticeship and Training. The utility or bidder shall provide, for example and as applicable, the following information for each craft the utility anticipates will work on the project:

(I) availability of training programs;

[46] As of this writing, the Commission's written Decision is pending.

(II) the names of specific training programs available;

(III) the curriculum of the specific training programs;

(IV) the cost of worker training;

(V) the duration of the training programs;

(VI) the total number of hours of on-the-job training required;

(VII) the total number of classroom hours required;

(VIII) the licenses and certifications obtained, if any;

(IX) a copy of training program standards for each training program; and

(X) a statement whether the training programs are United States Department of Labor registered apprenticeship programs and are accredited to award college credits.

(b) The employment of Colorado workers as compared to importation of out-of-state workers. The utility or bidder shall provide, for example and as applicable, the following information for each craft the utility anticipates will work on the project:

(I) estimated number of workers by job classification;

(II) estimated length of time of service, including total man hours, by job classification;

(III) percentage of Colorado workers by job classification; and

(IV) percentage of project man hours earned by Colorado workers by job classification.

(c) Long-term career opportunities. The utility or bidder shall provide, for example and as applicable, the following information for each craft the utility anticipates will work on the project: job classifications, licenses, certifications and skills that will be applied and the long-term career opportunities for each job classification; and

(d) Industry-standard wages, health care, and pension benefits. The utility or bidder shall provide, for example and as applicable, the following information for each craft the utility anticipates will work on the project:

(I) range of wages by job classification;

(II) healthcare benefits by job classification;

(III) pension benefits by job classification;

(IV) prevailing wages and fringe benefits (healthcare benefits, pension benefits and other compensation) based on industry standards and the current Colorado labor agreements by job classification; and

(V) wages and fringe benefits (healthcare benefits, pension benefits and other compensation) by job classification.

2.17 CONFIDENTIAL AND HIGHLY CONFIDENTIAL INFORMATION

In this Section, the Company provides lists of the information related to the ERP plan proceeding that the Company considers public, confidential, and highly confidential as required by Rule 3604(j).

Public Information

The following Public Service information that is relevant to the 2021 ERP & CEP is or will be public information, either as a result of Public Service's filing the information in Phase I or Phase II of the 2021 ERP & CEP or due to a prior filing with the Commission, the State of Colorado, or federal agencies:[47]

Public Service Company of Colorado Information

- Sales by Customer Class
- Revenue by Customer Class
- Number of Customers by Customer Class
- Sales by Tariff
- Revenue by Tariff
- Sales per Customer by Tariff
- Revenue per kWh by Tariff
- Sales Made to Wholesale Customers
- Revenue from Sales to Wholesale Customers
- Affiliate Transactions
- Reserve Margin
- Contingency Plan
- Resource Need for Resource Acquisition Period
- Renewable Energy Standard
- RES Compliance Position
- Renewable Energy Standard Adjustment
    - Balance
    - Forecast
- Sales and Demand Forecast
    - Total Sales
    - Total Demand
    - Sales by Customer Class
    - Demand by Customer Class
- Aggregate CO_2 Cost Projection
- Monthly On/Off Peak Market Prices
- Market Emissions Assumptions

[47] Information listed is not all inclusive.

Company-Owned Generation Resource Information

- Aggregate Cost of Production
- Energy Production
- Depreciation and Amortization Expense
- Estimated Average Service Life
- Peak Load
- Plant Hours Connected to Load
- Capacity
- Plant Production Costs
- Average Cost per kWh
- Average Heat Rate
- Total Fuel Consumed
- Fuel Types
- Capacity Factor
- Availability Factor
- Estimated Remaining Useful Lives
- Total Emissions by Type
- Plant Emissions by Type
- Total Fuel Used by Type
- Fuel Cost
    - Historical Coal Cost
    - Historical Gas Cost
    - Coal Cost Projection
    - Gas Cost Projection

Purchased Generation Resource Information

- Capacity
- Energy Purchased
- Cost of Energy Purchased
- Contract Duration
- Contract Modification Terms

Transmission Resource Information

- Operating Costs
- Wheeled Energy
- Wheeled Capacity
- Wheeling Revenue
- Purchase and Sale of Ancillary Services
- Peak Load
- Line Size and Length
- Capacity from Wheeling and Coordination Agreements
- Planned Additions
- Injection Capability

EnCompass Model Data

Input Information

- Inflation Rate
- Federal Tax Rate
- State Tax Rate
- Discount Rate
- Weighted Average Cost of Capital
- Variable O&M Escalation Rate
- Fixed O&M Escalation Rate
- Construction Cost Escalation Rate
- SO_2 Pricing
- NO_x Pricing
- CO_2 Pricing
- Wind Integration Costs
- Wind Related Coal Cycling Costs
- Solar Integration Costs
- Natural Gas Price Volatility Mitigation Adder (PVM)
- Annual / Monthly Peak Demand
- Annual / Monthly Total Energy Demand
- Line Loss Assumptions
- DSM Forecast
- Load Management Resources
- Reserve Margin Requirements
- Spinning Reserve Requirement
- Wind Curtailment Pricing
- System Average Colorado Coal Prices
- System Average PRB Coal Prices
- Blended Natural Gas Prices – not proprietary forecasts
- Oil Prices
- Capacity Credit Pricing
- Capacity Credit Limits
- In-Service Dates
- Retirement Dates
- Unit Capacities
- PPA In-service Dates
- PPA Retirement Dates
- PPA Capacities
- Generic Resources
  - Name Plate Capacity
  - Summer Peak Capacity
  - Capital Costs
  - Transmission Interconnection Costs
  - Transmission Grid Upgrade Costs

- Firm Fuel Supply Costs
- Book Life
- Fixed O&M
- Variable O&M
- Heat Rate Curves
- Forced Outage Rates
- Typical Annual Maintenance Requirements
- CO_2 Emission Rate
- NO_x Emission Rate
- SO_2 Emission Rate

Output Information

- Annual System Peak
- Annual System Capacity Obligation
- Total System Capacity
- Capacity Additions (Expansion Plans)
- Capacity Retirements
- System Capacity Mix Aggregated into the Following Categories
  - Load Management
  - Coal
  - Carbon Free Baseload
  - Biomass
  - Gas Combined Cycle
  - Gas Combustion Turbine
  - Oil
  - Hydro
  - Pumped Storage
  - Wind
  - Solar
  - Geothermal
  - System Purchases / Sales
  - SPS Interchange
- System Emissions
  - CO_2
  - SO_2
  - NO_x
  - PM
  - Mercury
- System Fuel Burn
  - Natural Gas
  - Coal
  - Oil
- Revenue Requirements for Capital Projects (not all Public Service capital projects are modeled) Aggregated into the Following Categories

  - Coal
  - Carbon Free Baseload
  - Biomass
  - Gas Combined Cycle
  - Gas Combustion Turbine
  - Oil
  - Hydro
  - Pumped Storage
  - Wind
  - Solar
  - Geothermal
- Fixed Costs Including Fixed O&M and PPA Capacity Payments Aggregated into the Following Categories
  - Coal
  - Carbon Free Baseload
  - Biomass
  - Gas Combined Cycle
  - Gas Combustion Turbine
  - Oil
  - Hydro
  - Pumped Storage
  - Wind
  - Solar
  - Geothermal
  - Capacity Credits
- Energy Costs Including Fuel, Variable O&M, and Energy Payments Aggregated into the Following Categories
  - Coal
  - Carbon Free Baseload
  - Biomass
  - Gas Combined Cycle
  - Gas Combustion Turbine
  - Oil
  - Hydro
  - Pumped Storage
  - Wind
  - Solar
  - Geothermal
  - Short-term Energy Purchases
- Total Emission Costs
  - CO_2
  - NO_x
  - SO_2
  - PM
  - Mercury

- Total PVM Costs
- Total Wind Integration Costs
- Total Wind Related Coal Cycling Costs
- Total Wind Curtailment Costs
- Total DSM Costs

Concerning the EnCompass model that the Company used to represent the Public Service system,[48] the model has millions of discrete data points that it uses to represent the Public Service system. The model is very much an organic model whose raw inputs are not in discrete files that can be provided or that would be easily understood or manipulated. Specific questions concerning derivations of EnCompass inputs will likely receive a specific and useful response. Public Service cautions that the Company cannot answer all non-specific EnCompass input questions. An example of a non-specific question would be: "Provide all EnCompass input files," or "Provide all EnCompass input files and assumptions." There are no such files, and the assumptions are too numerous to list in a productive manner. However, subject to Commission approved treatment of confidential data, the fully resolved EnCompass database (i.e. final model data only, without underlying support) is easily exportable from the model itself.

Confidential Information

Public Service will seek to protect the following proprietary information as confidential information:

EnCompass Model Data

Input Information

- Hourly Load Patterns
- DSM Hourly Patterns
- System carbon rate
- Market Import Constraints
- Unit Seasonal Deration Profiles
- Unit Variable O&M
- Unit Fixed O&M
- System Annual Fixed Gas Delivery Charges
- Unit Average Maintenance Requirements
- Unit Average Forced Outage Rate
- Unit Contribution to Spinning Reserve
- Unit Level Economic Minimum

[48] The model was used to produce alternative plans for the Phase I filing and will be used to evaluate the bids in a solicitation.

- Unit Level Emergency Minimum
- Unit Emission Rates
    - SO_2
    - NO_x
    - CO_2
    - PM
    - Mercury
- PPA Capacity Pricing (to the extent the counter party agrees to allow contract terms to be divulged)
- PPA Energy Pricing (to the extent the counter party agrees to allow contract terms to be divulged)
- PPA Energy Schedules (to the extent the counter party agrees to allow contract terms to be divulged)
- PPA Contribution to Spinning Reserves
- PPA Seasonal Capacity Derate Profiles
- PPA Emission Rates
    - CO_2
    - SO_2
    - NO_x
    - PM
    - Mercury
- Hourly Wind Patterns
- Hourly Solar Patterns

Output Information

- Unit Level Maximum Capacity
- Unit Level Summer Accredited Capacity
- Unit Level Generation
- Unit Level Fuel Consumed
- Unit Level Average Heat Rate
- Unit Level Total Variable O&M
- Unit Level Fixed O&M
- DSM Hourly Patterns
- Unit Level Capital Expenditures (note not all Public Service capital expenditures are modeled)
- Unit Level Rate Base (note rate base not modeled for all Public Service units)
- Unit Level Revenue Requirements (note revenue requirements not modeled for all Public Service units)
- Unit Level Emissions
    - NO_x
    - SO_2
    - CO_2
    - PM

    - Mercury
- PPA Maximum Capacities
- PPA Summer Accredited Capacities
- PPA Generation
- PPA Capacity Factors
- PPA Total Energy Payments (to the extent the counter party agrees to allow contract terms to be divulged)
- PPA Total Capacity Payments (to the extent the counter party agrees to allow contract terms to be divulged)
- PPA Emissions
    - NO_x
    - SO_2
    - CO_2
    - PM
    - Mercury

<u>Highly Confidential Information</u>

Public Service will seek to protect the following proprietary information as highly confidential information:

- Unit Level Delivered Fuel Costs
- Hourly Market Price Data
- Unit Level Heat Rate Curves
- Unit Detailed Maintenance Schedules
- Bid Information of any Sort (from the Company and from other entities)
- Any information protected by confidentiality clause of a PPA
- EnCompass Files
- Forecasted Unit Level data included in Clean Energy Plan Guidance Verification Workbooks (completed by the Company with Company-specific data and created by the Air Pollution Control Division ("APCD") at the Colorado Department of Public Health & Environment ("CDPHE")

<u>Information that Public Service will Provide Bidders</u>

Public Service will provide the following Public Service-developed information to bidders with respect to their own bids after initial bid screening and before EnCompass modeling:

- Levelized Cost of Energy or Capacity (LEC or LCC), as applicable
- Estimated Transmission Interconnection Costs, as applicable
- Estimated Transmission Network Upgrades, as applicable
- Gas Supply Costs, as applicable
- Intermittent Renewable Integration Costs or Credits, as applicable

Protection of Bid Information, Modeling Inputs and Assumptions, and Bid Evaluation Results

Public Service will seek to protect all bid information and bid evaluation results (including Company self-build proposals) that would reveal specific bid pricing or other bid information, as highly confidential information in accordance with the Commission's rules, until completion of the resource acquisition process (i.e., until the last contract for a resource that meets a portion of the 2021 ERP & CEP resource need is executed). Upon completion of the resource acquisition process, Public Service will post on its website the following bid information as required by Rule 3613(k):

- Bidder Name
- Bid Price (Utility Cost for Utility–Owned Proposals)
- Generation Technology Type
- Size of Facility
- Contract Duration (Expected Useful Life of Utility Resource)
- Purchase Option Details as relevant

Additionally, as required by Rule 3613(j), within fourteen months after the receipt of bids in the competitive acquisition process, the Company will file a proposal in the ERP proceeding that addresses the public release of all confidential and highly confidential information related to bids for potential resources and resources the utility proposed to build and own (e.g., the 120-Day Report, the independent evaluator's report, and all documents related to these reports filed by the Company, parties, or the independent evaluator). Pursuant to the process set forth by Rule 3613(j), parties will have 30 calendar days after the Company files its proposal to file responses, and the Company may reply to any responses filed within ten calendar days. The Commission then issues an order specifying to the Company and other parties the documents that shall be refiled as public information.

2.18 UPDATED STUDY REPORTS

Pursuant to Commission Decision No. C17-0316 (Phase I Decision) and Decision No. C18-0761 (Phase II Decision) in the 2016 ERP, Proceeding No. 16A-0396E, the Commission directed the Company to file certain updated studies with its next ERP. Accordingly, Table 2.18-1 below summarizes the updated studies, the 2016 ERP Decision reference, and where the updated study report can be found in the Company's 2021 ERP & CEP. As reflected in Table 2.18-1, the updated study reports are attached as Appendices to Volume 2 and are also provided as an attachment to the Direct Testimony of the Company witness that sponsors the respective study.

Table 2.18-1 Summary of Updated Study Reports

Updated Study	Required By	Where in 2021 ERP Filing
Planning Reserve Margin and Resource Adequacy Study	Decision No. C17-0316, ¶ 49, Ordering ¶ 5	Appendix A; and Attachment KDC-1
Flex Reserve and Supplemental Flex Reserve	Decision No. C17-0316, ¶ 145, Ordering ¶ 13; and Decision No. C18-0761, ¶¶ 139(b)-140, Ordering ¶ 8	Appendix B and Appendix C; Attachment KLS-3 and Attachment KLS-4
Wind and Solar Integration	Decision No. C18-0761, ¶¶ 139(c-d)-140, Ordering ¶ 8	Appendix D; and Attachment KLS-1
Storage Credits and Operation	Decision No. C18-0761, ¶¶ 139(a)-140, Ordering ¶ 8	Volume 2, Section 2.10
Effective Load Carrying Capability	Decision No. C18-0761, ¶¶ 139(e)-140, Ordering ¶ 8	Appendix E; and Attachment KLS-2
Coal Supply Report	Decision No. C17-0316, ¶ 156, Ordering ¶ 14	Appendix F

ASTRAPÉ CONSULTING
innovation in electric system planning

Planning Reserve Margin and Resource Adequacy Study

Final Report

03/22/2021

PREPARED FOR

Public Service Company of Colorado ("PSCo")

PREPARED BY

Kevin Carden
Alex Krasny Dombrowsky
Cole Benson
Astrapé Consulting

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This study was performed by Astrapé Consulting at the request of Public Service Company of Colorado (PSCo) to identify a target reserve margin[1] and also to comprehensively assess resource adequacy risks that may affect a range of resource planning decisions.

The PSCo electric system is currently in a state of rapid transition. While PSCo has had significant wind resources for many years, additional wind, solar PV, and solar PV with battery resources are expected to be added to the system in the near future. As battery storage costs decline, standalone battery storage could also be added to the system. Efficiently managing resource adequacy in the midst of this transition is challenging because these incipient resources have limited dispatchability, energy constraints, and limited or not yet available operational history. Given the varying penetrations of these energy-limited resources over the next decade and their dynamic interactions, Astrapé was tasked with analyzing the reliability of an evolving resource mix on the PSCo system from 2021 to 2030.

To calculate the necessary reserve margin for the PSCo system, Astrapé Consulting utilized their reliability model, SERVM (Strategic Energy and Risk Valuation Model), to perform over 9,500 yearly simulations with 1-hour granularity at various reserve margin levels. SERVM calculates multiple physical reliability metrics in order to provide a wholistic perspective on PSCo reliability. Each of the 9,500 yearly simulations was developed through stochastic modeling of the uncertainty of load, renewable generation, economic growth, unit availability, and transmission availability. In addition to the Base Case analysis of study years 2021, 2023, 2026, and 2030, sensitivity analyses were performed to understand the importance of varying assumptions.

The standard for resource adequacy planning in the United States is to procure sufficient resources to expect to shed firm load less than once every 10 years. This is commonly referred to as the 1-day-in-10 standard. This standard has historically been interpreted one of two ways: 1) A single firm load shed event over a 10-year period calculated with the Loss of Load Expectation (LOLE) metric or 2) 24 hours of firm load shed over a 10-year period calculated with the Loss of Load Hours (LOLH) metric. The first interpretation of resource adequacy is referred to in shorthand as 0.1 LOLE, and the second interpretation is referred to as 2.4 LOLH. These two interpretations of the 1-day-in-10 standard result in materially different levels of reliability since a single load shed event might only last 2-3 hours. Thus, the 2.4 LOLH interpretation generally has about 10 more days with firm load shed than the 0.1 LOLE interpretation. As documented in numerous reliability reports[2], nearly all planning entities, including all independent system operators (ISOs), now use the 0.1 LOLE interpretation to plan for resource adequacy. All other assumptions held constant, a 0.1 LOLE based reserve margin is typically 5 percentage points higher than a 2.4 LOLH based reserve margin[3]. To normalize for the difference in reliability, studies using the 2.4 LOLH interpretation often involve modeling the electric market purchases and sales with either a simple representation with limited availability or no representation at all. These conservative assumptions of electric market access applied in 2.4 LOLH-based studies often result in reserve margins of similar magnitude as those from studies which use the 0.1 LOLE

[1]Throughout this report, reserve margin is defined by the formula: reserve margin = (resources – firm peak demand) / (firm peak demand).

[2]https://cdn.misoenergy.org/20200610%20RASC%20Item%2005a%20RAN%20Reliability%20Requirements%20Presentation%20(RASC010%20RASC011%20RASC012)451665.pdf

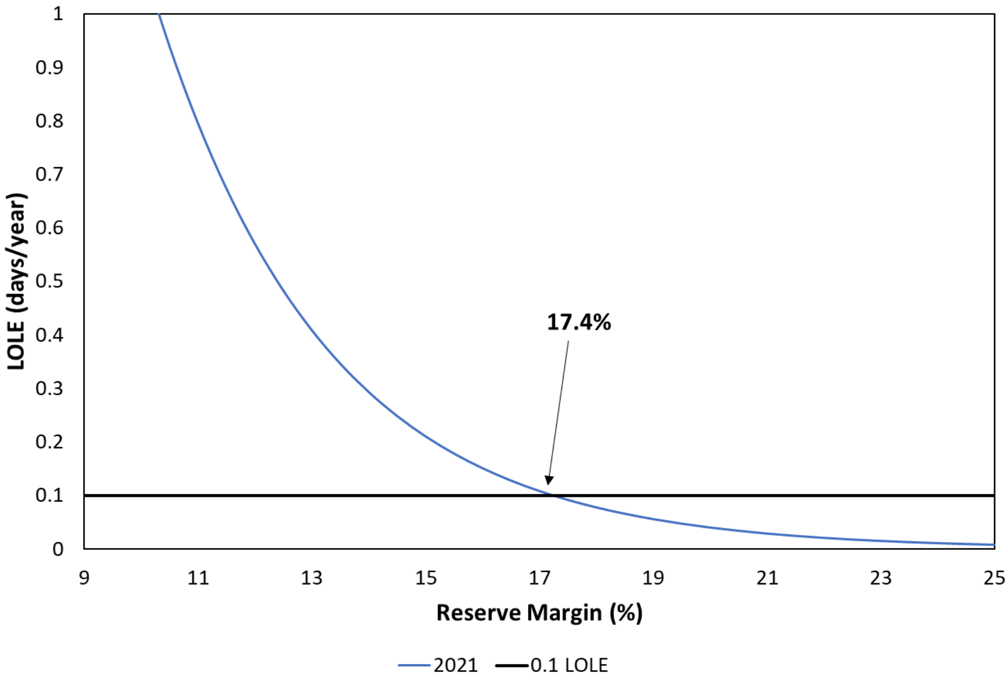
[3] https://www.astrape.com/?ddownload=637 p.iii

interpretation, plus a more realistic representation of support that can be provided from the electric market.

In PSCo's reserve margin study performed in 2008, the target reserve margin of 16.3% was based on the 2.4 LOLH interpretation and an electric market assumption of access to imports of 200 MW[4]. For this current study, Astrapé is using the industry standard interpretation of 0.1 LOLE but has also included a more detailed consideration of the reliability benefit of the electric market in its determination of the target reserve margin[5]. The shift to the industry standard 0.1 LOLE reliability metric increased the target reserve margin while the more detailed electric market assessment put downward pressure on the target reserve margin.

The results of the SERVM simulations for the Base Case for study year 2021 demonstrate that as the target reserve margin increases, system LOLE declines, meeting the 0.1 LOLE standard at a 17.4% reserve margin, as illustrated in Figure ES1.

Figure ES1. 2021 LOLE



Theoretically, if the reliability contribution of energy-limited resources and the electric market were to be known with certainty, the target reserve margin could remain static across the study years of 2021, 2023, 2026, and 2030. However, the changing resource mix in PSCo brings added uncertainty because the reliability contributions of new resources, the correlations between the generation output at different renewable sites, and the correlations amongst different resource technologies are not known with precision. And there are external neighbor sources of resource adequacy uncertainty as well. Within the PSCo Balancing Authority Area (PSCo BAA) and the surrounding regions, announcements of fossil fuel unit closures are significant over the coming decade without complete certainty what the replacement resources will be. These external neighbor changes create added uncertainty to the

[4] The transmission import capability was modeled as 200 MW plus or minus 50 MW on a Monte Carlo basis. The non-firm energy was assumed to be always available.
[5] Non-firm electric market energy in the simulations provides reliability benefits to PSCo but is not included as a resource in the reserve margin calculation.

reliability support PSCo's neighbors can provide PSCo as well as the general level of reliability of the neighboring systems. These variations are reflected in the target reserve margin results that meet the 0.1 LOLE standard, shown in Table ES1, for the Base Cases. Astrapé recommends a target reserve margin range of 18% to 20% to adequately reflect the uncertainties and reliability implications of PSCo's system.

Table ES1. 0.1 LOLE Results

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

Ultimately, Astrapé believes that further work in the coming years is warranted on assessing the reliability contributions of different resource technologies as their penetrations on the PSCo system increase and as PSCo's neighbors transition their systems toward more energy-limited resources. This will require future renewable output data collection, operational history of battery storage, and more electric market transaction history. This additional effort could tighten the future range of reserve margins that should be targeted. In the meantime, a target reserve margin range of 18% to 20%, applied to the 50th percentile probability demand forecast, adequately reflects the reliability risk of the changing system.

PSCo plans to implement the results of this study in its next ERP cycle by acquiring longer term generation resources as necessary to achieve an 18.0% reserve margin plus carrying 1) an additional 45 MW of planning reserve in accordance with PSCo's wholesale contract with Intermountain Rural Electric Association and Holy Cross Energy, and 2) additional resources in certain years to achieve the reserve margin levels reflected in Table ES1, through shorter term power purchases.

INPUT ASSUMPTIONS

STUDY YEARS

The selected study years are 2021, 2023, 2026, and 2030. The results of the SERVM simulations should be used as an input into procurement decisions made in the Company's next ERP cycle. Given the uncertainty associated with the reliability contribution offered to power supply systems from energy-limited storage, renewable resources, and the electric market, Astrapé recommends analyzing reserve margin needs relatively frequently. Recent generation reliability events in California highlight the need for careful attention to reliability in systems with increasing penetrations of renewable resources and reliance on non-firm energy imports.

STUDY TOPOLOGY

Figure 1 shows the study topology that was used for this study. To thoroughly quantify resource adequacy, it is important to capture the load, renewable generation, and generator outage diversity that a system has with its neighbors. For this study, the PSCo system was modeled along with its Joint Dispatch Agreement (JDA) neighbors within the PSCo Balancing Authority Area (BAA) and external neighbors. The surrounding systems and regions captured in the modeling include:

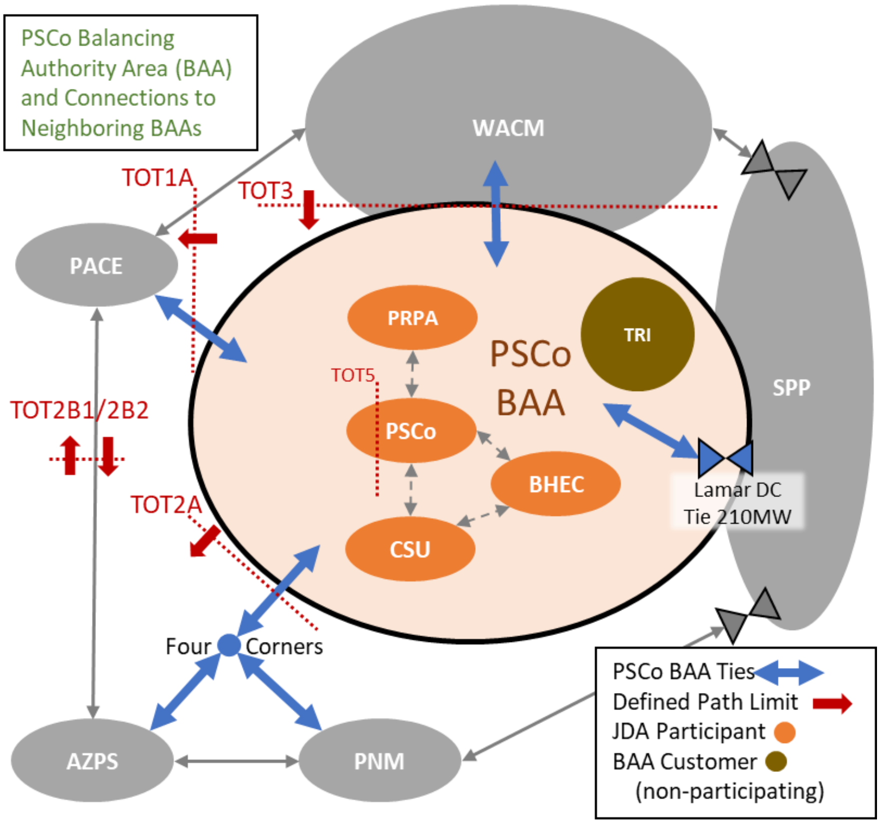
- JDA Neighbors
    - Platte River Power Authority (PRPA)
    - Colorado Springs Utilities (CSU)
    - Black Hills Energy Colorado (BHEC)
- External Neighbors
    - Tri-State (TRI)
    - Western Area Power Administration-Colorado Missouri (WACM)
    - PacifiCorp East (PACE)
    - Southwest Power Pool (SPP)[6]
    - Public Service Company of New Mexico (PNM)
    - Arizona Public Service (AZPS)

Sometime during the year 2022, PSCo, PRPA, CSU, and BHEC are projected to join the Western Energy Imbalance Market (WEIM). PACE and AZPS are already WEIM members, and PNM is projected to join in 2021. The reliability contributions of these JDA neighbors and external neighbors are captured within the study topology.

SERVM uses a pipe and bubble representation where non-firm energy can be shared based on economics but subject to transmission constraints. The modeled regions and transmission connecting them are shown in Figure 1. The transmission import and export limits are discussed in the External Assistance section of the report.

[6] SPP was modeled with only the load and resources of Southwestern Public Service (SPS).

Figure 1. Study Topology



LOAD MODELING

Table 1 displays PSCo seasonal peak demand forecast for 2021, 2023, 2026, and 2030 under normal weather conditions. PSCo's wholesale customers' loads were modeled as a part of PSCo load. The wholesale customers included were Intermountain Rural Electric Association (IREA), Holy Cross Energy, Grand Valley Power, Yampa Valley Electric Association, and City of Burlington.

Table 1. PSCo Aggregate Load Forecasts

PSCo	Summer	Winter
2021	7,309	5,678
2023	7,404	5,720
2026	7,622	5,877
2030	8,063	6,183

39 historical weather years (1980-2018) were developed to reflect the influence of weather on load, wind, solar, and hydro generation and the associated uncertainty. For developing the synthetic load profiles used in the study, a neural network program was used to develop relationships between weather observations and hourly load from historical data provided by PSCo. The historical load data was from June 2013 through December 2019. The historical weather consisted of hourly temperature

from Denver supplemented by a station in Aurora for days with insufficient data. Other weather stations were considered but ultimately were excluded due to the lack of a statistical significance.

Before being input into the neural network software, the temperature data for weather years 1980-2010 was adjusted to create the same baseline expectation for hot weather for the entire 1980-2018 weather year period. This translates to a flat slope over time on the expected frequency of hot weather. The adjustment does not increase the maximum temperature seen in each weather year. Figure 2 below shows the number of days with temperatures above 90°F in each PSCo weather year before and after the adjustment and Figure 3 shows the degrees added to each year.

Figure 2. Temperature Adjustment

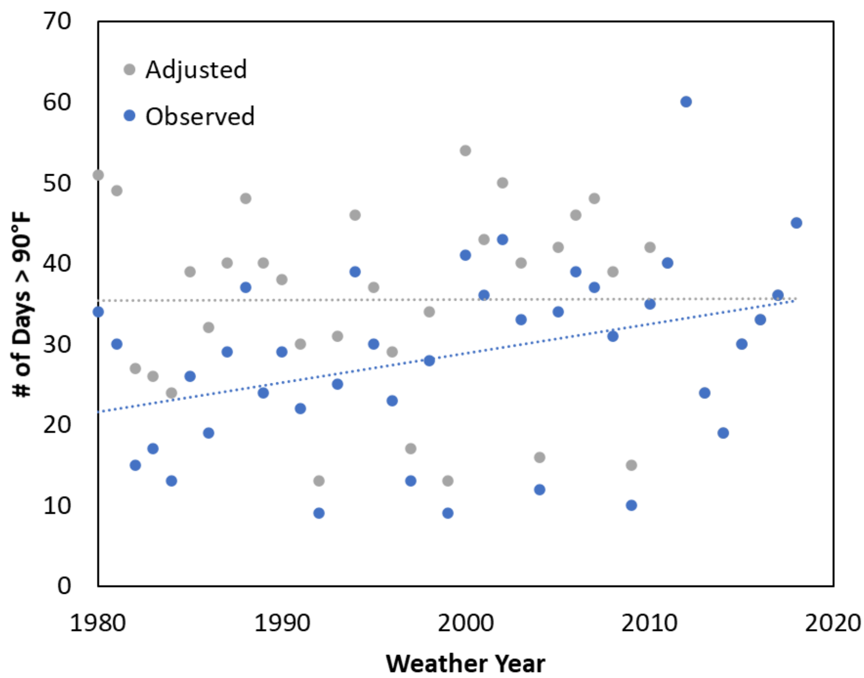
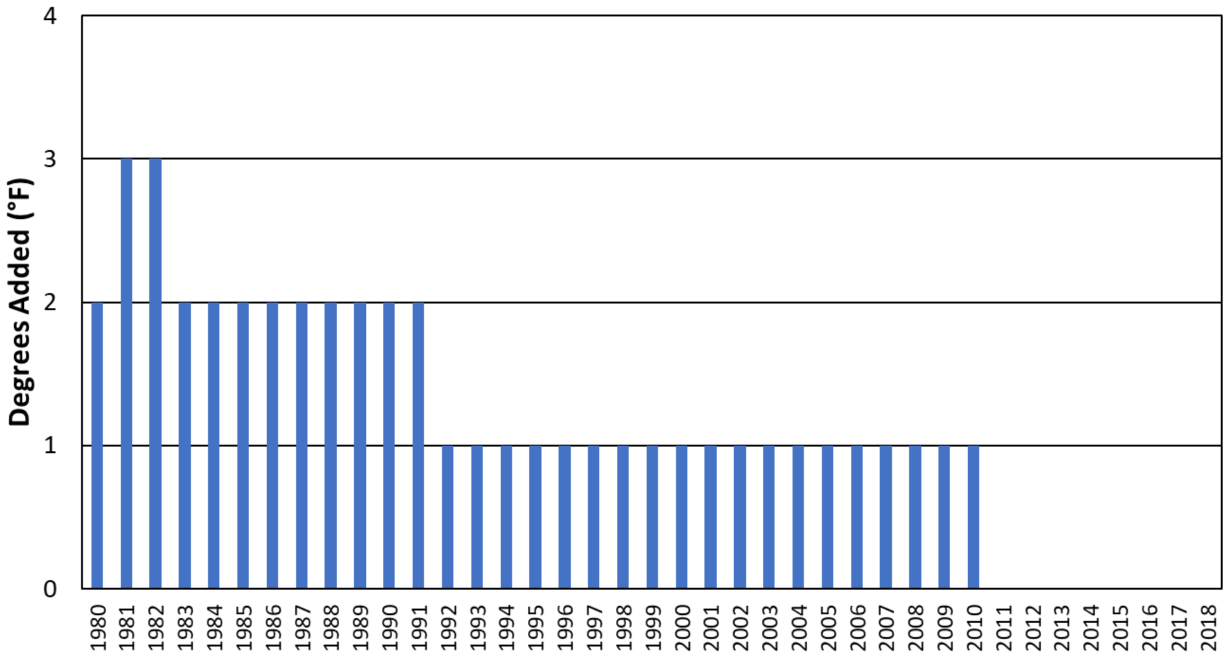


Figure 3. Degrees Added



Other inputs into the neural network model consisted of an hour of week factor and an average temperature from the past 8, 24, and 48 hours. Different weather and load relationships were built for each of the three defined seasons (winter, summer, and shoulder).

These relationships were then applied to the 39 years of weather to develop 39 synthetic load shapes. Equal probabilities were given to each of the 39 load shapes in the simulation. Table 2 below shows the results of the load modeling by displaying the peak load and the peak load variance for both the winter and summer seasons. The load variance is calculated by dividing the difference between each year's peak load and the mean by the mean.

Table 2. Peak Load Variability

Weather Year	Summer Peak (MW)	Winter Peak (MW)	Summer Variability (%)	Winter Variability (%)
1980	6,784	5,499	-1.13%	-4.68%
1981	6,928	5,554	0.96%	-3.73%
1982	6,779	5,949	-1.21%	3.12%
1983	6,734	6,230	-1.86%	7.99%
1984	6,725	6,149	-1.99%	6.59%
1985	6,717	5,927	-2.11%	2.74%
1986	6,768	5,508	-1.37%	-4.52%
1987	6,778	5,635	-1.22%	-2.32%
1988	6,751	5,625	-1.62%	-2.50%
1989	7,202	6,038	4.96%	4.66%
1990	7,120	6,123	3.76%	6.14%
1991	7,028	5,390	2.42%	-6.57%

1992	6,844	5,429	-0.26%	-5.89%
1993	6,971	5,741	1.59%	-0.49%
1994	6,878	5,433	0.24%	-5.82%
1995	6,752	5,524	-1.60%	-4.25%
1996	6,857	5,961	-0.07%	3.33%
1997	6,802	5,974	-0.87%	3.55%
1998	6,735	5866	-1.85%	1.68%
1999	6,585	5,407	-4.03%	-6.27%
2000	6,938	5,581	1.11%	-3.26%
2001	6,751	5,925	-1.62%	2.70%
2002	6,838	5,612	-0.35%	-2.72%
2003	6,942	5,710	1.17%	-1.02%
2004	6,762	5,917	-1.46%	2.57%
2005	7,194	5,723	4.84%	-0.80%
2006	6,993	5,802	1.91%	0.57%
2007	6,883	5,687	0.31%	-1.42%
2008	7,179	6,071	4.62%	5.23%
2009	6,499	5,791	-5.29%	0.38%
2010	6,675	6,029	-2.72%	4.51%
2011	6,876	5,922	0.21%	2.65%
2012	7,158	5,575	4.32%	-3.36%
2013	6,809	5,845	-0.77%	1.32%
2014	7,027	6,008	2.41%	4.14%
2015	6,750	5,685	-1.63%	-1.46%
2016	6,711	5,618	-2.20%	-2.62%
2017	6,782	5,856	-1.16%	1.51%
2018	7,107	5,672	3.57%	-1.68%
Mean	6,862	5,769	-	-
Minimum	6,499	5,390	-5.29%	-6.57%
Maximum	7,202	6,230	4.96%	7.99%

Loads for each external region were developed in a similar manner as the PSCo loads. A relationship between hourly weather and publicly available hourly load was developed based on recent history, and then this relationship was applied to 39 years of weather data to develop 39 synthetic load shapes[7]. The same temperature adjustment applied to create the synthetic PSCo load shapes was also applied to each neighbor shape. Tables 3 and 4 show the resulting seasonal weather diversity between PSCo and the external neighbors. When the PSCo system is peaking in summer, the aggregate of the neighboring regions is only 3.97% below the system coincident peak load on average over the 39-year period and 2.97% below in winter suggesting the market is likely to be relatively tight during PSCo's peak conditions. However, since hourly load and renewable profiles were constructed for each region, the unique pattern of diversity benefit is fully captured in the modeling. The same approach used for constructing neighboring loads is used by Astrapé's other clients including MISO, SPP, and ERCOT, and

[7] FERC 714 Forms were accessed to pull hourly historical load for all neighboring regions.

the magnitude of diversity found in this study is similar to that of studies performed by or on behalf of the other entities mentioned.

Table 3. External Region Diversity – Summer

	Non-Coincident Peak (MW)	System Coincident Peak (MW)	PSCo Peak (MW)	Load Diversity (% below system coincident peak)	Load Diversity (% below non-coincident peak)	
				At PSCo Peak	At System Coincident Peak	At PSCo Peak
PSCo	6,862	6,525	6,862	-5.17%	4.92%	0.00%
AZPS	17,979	17,320	15,573	10.08%	3.67%	13.38%
TRI	2,636	2,515	2,491	0.99%	4.58%	5.52%
PACE	9,135	8,621	8,201	4.87%	5.63%	10.22%
PNM	2,034	1,837	1,798	2.14%	9.67%	11.61%
WACM	4,373	4,141	4,139	0.05%	5.30%	5.35%
BHEC	637	592	597	-0.93%	7.06%	6.19%
CSU	909	839	852	-1.47%	7.68%	6.32%
PRPA	677	612	620	-1.28%	9.61%	8.44%
SPP	5,979	5,563	5,505	1.04%	6.95%	7.92%
System	51,220	48,564	46,636	3.97%	5.18%	8.95%

Table 4. External Region Diversity – Winter

	Non-Coincident Peak (MW)	System Coincident Peak (MW)	PSCo Peak (MW)	Load Diversity (% below system coincident peak)	Load Diversity (% below non-coincident peak)	
				At PSCo Peak	At System Coincident Peak	At PSCo Peak
PSCo	5,769	5,420	5,769	-6.45%	6.06%	0.00%
AZPS	10,734	9,622	8,556	11.09%	10.36%	20.30%
TRI	2,185	2,072	2,046	1.26%	5.20%	6.39%
PACE	7,587	7,212	7,019	2.68%	4.94%	7.49%
PNM	1,540	1,403	1,366	2.62%	8.95%	11.34%
WACM	3,943	3,667	3,664	0.08%	7.00%	7.07%
BHEC	624	571	570	0.21%	8.57%	8.76%
CSU	791	722	737	-2.11%	8.68%	6.76%
PRPA	510	466	472	-1.23%	8.65%	7.53%
SPP	4,290	4,039	3,951	2.18%	5.86%	7.91%
System	37,975	35,194	34,149	2.97%	7.32%	10.07%

ECONOMIC LOAD FORECAST ERROR

Economic load forecast error estimates were developed to isolate the economic uncertainty that PSCo has in its three-year-ahead load forecasts. The three-year-ahead load forecasts were selected for this study because three years is a reasonable lower bound on the amount of time required to place new resources in service to meet future resource needs, given the time required to identify the need, solicit projects, receive PUC approval, and acquire resources. The difference between Congressional Budget Office (CBO)[8] GDP forecasts three years ahead and actual data was fit to a normal distribution, which was then used as economic load forecast error in the model. Because electric load grows at a slower rate than GDP, a 40% multiplier was applied to the raw CBO forecast error distribution. Table 5 shows the economic load forecast errors and associated probabilities. As an illustration, 24.10% of the time, it is expected that load will be under forecasted by 2% three years out. Within the simulations, when PSCo under forecasts load, the external neighbors also under forecast load. The SERVM model utilized each of the 39 weather years and applied each of the five load forecast error multipliers to each hour to create 195 different load scenarios. Each weather year was given equal probability of occurrence.

Table 5. Economic Load Forecast Error

Load Forecast Errors	Associated Probabilities	Economic Load Forecast Error Multiplier
-4%	7.26%	0.96
-2%	24.10%	0.98
0%	37.28%	1
2%	24.10%	1.02
4%	7.26%	1.04

[8] Astrapé uses CBO data primarily because client-generated, weather-normalized forecast error data generally suggests larger magnitude economic forecast error impacts. Also, CBO data is available for more than two decades which demonstrates periods of both under forecast and over forecast. Client-generated data is often one-sided because it does not cover long enough time periods.

PSCO GENERATION RESOURCES

The PSCO generation resources included in this study are outlined below in Tables 6 and 7. All thermal resources were committed and dispatched to load economically.

Table 6. PSCo Owned Thermal Resources

Unit Name	Unit Category	Summer Capacity (MW)	Winter Capacity (MW)
Cherokee CT5	PSC CC	168	176
Cherokee CT6	PSC CC	168	176
Cherokee ST7	PSC CC	240	248
FSV CT2	PSC CC	123	134
FSV CT3	PSC CC	128	139
FSV CT4	PSC CC	128	139
FSV ST1	PSC CC	301	304
RMEC CT1	PSC CC	145	157
RMEC CT2	PSC CC	145	157
RMEC ST3	PSC CC	290	301
Comanche 1	PSC Coal	325	325
Comanche 2	PSC Coal	335	335
Comanche 3	PSC Coal	500	511
Craig 1	PSC Coal	42	42
Craig 2	PSC Coal	40	40
Hayden 1	PSC Coal	135	135
Hayden 2	PSC Coal	98	98
Pawnee 1	PSC Coal	505	505
Cherokee 4G	PSC Gas	310	310
Alamosa CT1	PSC SC	13	17
Alamosa CT2	PSC SC	14	18
Blue Spruce CT1	PSC SC	130	144
Blue Spruce CT2	PSC SC	134	148
Fort Lupton CT1	PSC SC	44	50
Fort Lupton CT2	PSC SC	44	50
Fruita CT1	PSC SC	14	18
FSV CT5	PSC SC	144	159
FSV CT6	PSC SC	144	159
Manchief CT1	PSC SC	128	151
Manchief CT2	PSC SC	128	151
Valmont CT6	PSC SC	43	51
Valmont CT78	PSC SC	82	86

Table 7. PSCo Contract Thermal Resources

Unit Name	Unit Category	Summer Capacity (MW)	Winter Capacity (MW)
WM.Landfill.Gas	PPA Biomass	3	3
Brush 13 CC1x1	PPA CC	77	89
Brush 4 CC2x1	PPA CC	132	146
SWG Arapahoe CC2x1	PPA CC	118	129
Plains End	PPA SC	112	114
Plains End II	PPA SC	110	117
Spindle CT1&2	PPA SC	274	321
SWG Fountain Valley	PPA SC	238	253
PacifiCorp	Delivered Energy	150	150

Tables 8, 9, 10, and 11 show the PSCo renewable, battery storage, pumped storage, and demand response resources captured in the study.

Table 8. PSCo Solar and Battery Storage Resources

		Capacity (MW)			
Unit Name	**Unit Category**	**2021**	**2023**	**2026**	**2030**
Bighorn	PPA Solar	-	240	240	240
Cogentrix	PPA Solar	30	30	30	30
Community Energy	PPA Solar	120	120	120	120
Hartsel	PPA Solar	-	72	72	72
Hooper	PPA Solar	50	50	50	50
Iberdrola	PPA Solar	30	30	30	30
Neptune	PPA Solar	-	250	250	250
Storage Neptune	PPA Battery	-	125	125	125
Sandhill	PPA Solar	19	19	19	19
Sun Edison	PPA Solar	7	7	7	-
Thunder Wolf	PPA Solar	-	200	200	200
Storage Thunder Wolf	PPA Battery	-	100	100	100
2019 Solar RFP	PPA Solar	-	113	113	113
2019 Solar RFP	PPA Solar	-	100	100	100
Storage 2019 Solar RFP	PPA Battery	-	50	50	50
San Luis Valley	Generic Solar	-	-	150	300
Western Slope	Generic Solar	-	-	100	200
Northern Front Range	Generic Solar	-	-	200	400
Southern Front Range	Generic Solar	-	-	200	400
Solar Connect	PPA Solar	50	50	50	50
Solar Gardens	Distributed Solar	138	196	310	463
Solar On-Site	Distributed Solar	464	592	784	1,041

Table 9. PSCo Wind Resources

		Capacity (MW)			
Unit Name	**Unit Category**	**2021**	**2023**	**2026**	**2030**
Bronco Plains	PPA Wind	300	300	300	300
Cedar Creek	PPA Wind	301	301	301	301
Cedar Creek II	PPA Wind	251	251	251	251
Cedar Point	PPA Wind	252	252	252	252
Cheyenne Ridge	PSC Wind	500	500	500	500
Golden West	PPA Wind	249	249	249	249
Limon	PPA Wind	200	200	200	200
Limon II	PPA Wind	200	200	200	200
Limon III	PPA Wind	201	201	201	201
Logan	PPA Wind	201	201	201	201
Mountain Breeze	PPA Wind	169	169	169	169
Northern Colorado	PPA Wind	152	152	152	152
Northern Colorado II	PPA Wind	23	23	23	23
Peetz Table	PPA Wind	199.5	199.5	199.5	199.5
Ridgecrest	PPA Wind	29.7	29.7	29.7	29.7
Rush Creek	PSC Wind	600	600	600	600
Spring Canyon	PPA Wind	60	60	60	60
Colorado Green[9]	PSC Wind	162	162	162	162
Twin Buttes[10]	PSC Wind	75	75	75	75
ERZ 1	Generic Wind	-	-	125	250
ERZ 2	Generic Wind	-	-	125	250
ERZ 3	Generic Wind	-	-	250	500

[9] The volume of non-firm energy that can be imported across the Lamar DC Tie is affected by the output of Colorado Green and Twin Buttes.
[10] Same as footnote 9.

Table 10. PSCo Hydro and Pumped Storage Resources

		Capacity (MW)			
Unit Name	**Unit Category**	**2021**	**2023**	**2026**	**2030**
COB-Betasso Lakewood	Municipal Water Hydro	6.0	6.0	6.0	6.0
COB- Silver Lake	Municipal Water Hydro	3.0	3.0	3.0	3.0
DWB-Foothills	Municipal Water Hydro	2.3	2.3	2.3	2.3
DWB Strontia	Municipal Water Hydro	1.2	1.2	1.2	1.2
DWB-Dillon	Municipal Water Hydro	1.9	1.9	1.9	1.9
DWB-Roberts Tunnel	Municipal Water Hydro	6.1	6.1	6.1	6.1
DWB-Hillcrest	Municipal Water Hydro	2.3	2.3	2.3	2.3
DWB-Gross Reservoir	Municipal Water Hydro	8.1	8.1	8.1	8.1
Redlands Water & Power	Municipal Water Hydro	1.4	1.4	1.4	1.4
STS (Mt. Elbert)	Municipal Water Hydro	2.5	2.5	2.5	2.5
Shoshone 1	PSCo-Owned Run of River	7.5	7.5	7.5	7.5
Shoshone 2	PSCo-Owned Run of River	7.5	7.5	7.5	7.5
Georgetown 1	PSCo-Owned Run of River	0.8	0.8	0.8	0.8
Georgetown 2	PSCo-Owned Run of River	0.8	0.8	0.8	0.8
Ames	PSCo-Owned Run of River	3.8	3.8	3.8	3.8
Tacoma	PSCo-Owned Run of River	4.6	4.6	4.6	4.6
Cabin Creek 1	PSCo Pumped Storage	150	150	150	150
Cabin Creek 2	PSCo Pumped Storage	150	150	150	150

Table 11. PSCo Demand Response Resources

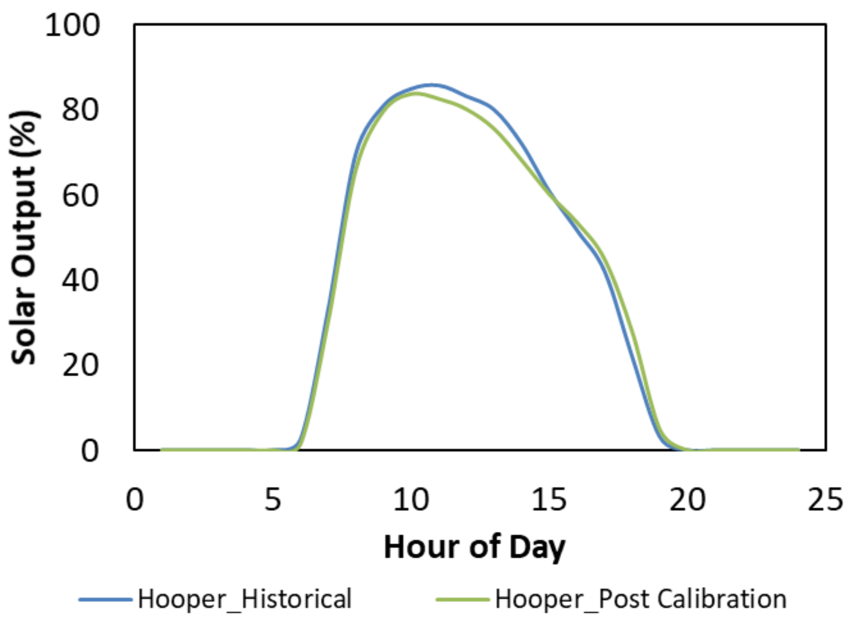
		Capacity (MW)			
Unit Name	**Unit Category**	**2021**	**2023**	**2026**	**2030**
AC Rewards	DR	33	45	57	68
Critical Peak Pricing	DR	38	46	48	50
ISOC160 Hour Customers	DR	116	117	118	116
ISOC40 Hour Customers	DR	12	12	12	12
ISOC80 Hour Customers	DR	60	61	62	61
Peak Day Partners	DR	5	8	8	10
Peak Partner Rewards	DR	47	51	55	58
Savers Switch Residential	DR	216	221	226	231

The changing resource mix in PSCo brings added uncertainty because the reliability contributions of new renewable and battery storage resources with little or no operational history are not known with precision. Actual generation data for solar, storage, wind, and hydro resources for the 1980-2018 weather year period would be the best source for determining the resource adequacy contribution of these resources. However, none of these resources existed for the entire weather year period and many have yet to be constructed. Using historical weather observations, recent-history generation data, and simulation methods, Astrapé created renewable generation profiles for solar, wind, and hydro resources for the 1980-2018 weather years as if the solar, wind, and hydro resources existed throughout the period. The correlations between the generation output at different renewable sites and amongst different resource technologies are not known with precision;

however, Astrapé used best-in-industry practices to create the synthetic profiles. The techniques preserve the correlations between load and renewable generation.

The solar units were simulated with 39 shapes representing 39 years of weather. The solar shapes were developed by Astrapé from data downloaded from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database Data Viewer. The data was then input into NREL's System Advisor Model (SAM) for each year and county to generate hourly profiles. The configuration of the solar projects in SAM were carefully calibrated with actual PSCo historical solar profiles. Figure 4 shows the average August solar shape at the Hooper site.

Figure 4. Hooper Average August Solar Shape



The wind units were simulated with 39 shapes representing 39 years of weather. The hourly wind shapes used in this study were developed using historical wind generation data provided by PSCo. Calculations were performed to reflect historical correlation between wind projects as well as projected correlations between future wind projects.

Wind generation profiles were also adjusted to account for historical wind lull trends. The frequency of having very low wind output for an extended period is an important driver of the reliability contribution of wind and correspondingly to the required reserve margin of the system. Construction of the synthetic wind profiles were done on a daily basis, so it was important to look at longer trends to ensure that extended lull periods in the historical wind data were replicated in the synthetic profiles. Figures 5 and 6 below reflect the modeled frequency of each lull period for <5%, <2.5%, and <1% of system wind output as a percentage of all hours and demonstrate that the synthetic profiles accurately reflect the expected frequency of each category of lull period.

Wind profiles were manually set to zero output when the temperature dropped below -20°F in recognition of how wind turbine electronic controls will shut the wind turbines down at extreme cold temperatures. While some of PSCo's wind projects had cold temperature cut outs above -20°F, given that reliability issues were primarily in the summer even in 2030 scenarios, the additional effort to create more discrete cold temperature cut out profiles was deemed unnecessary.

Figure 5. Historical Wind Lull Data

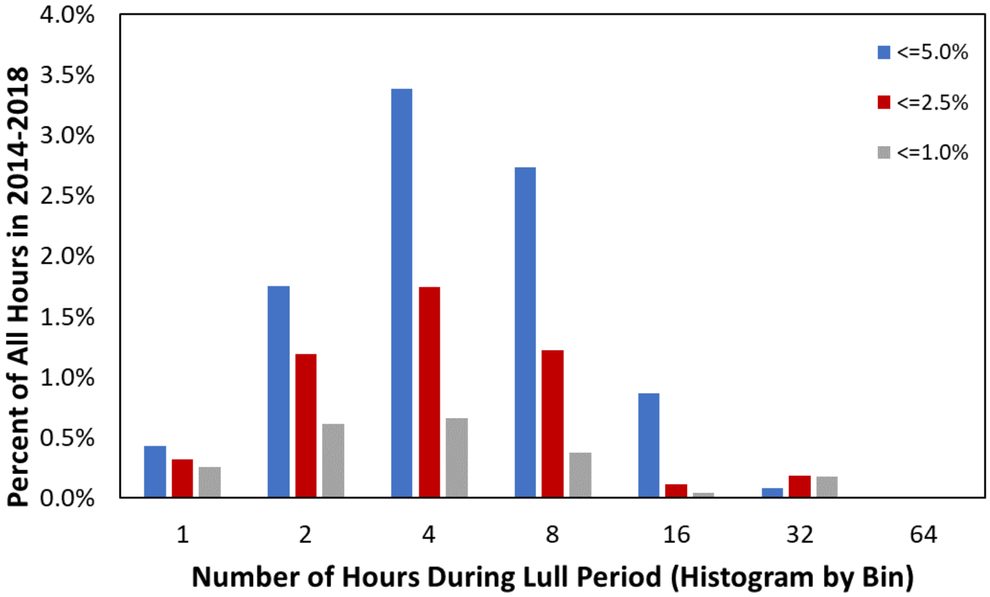


Figure 6. Synthetic Wind Lull Data

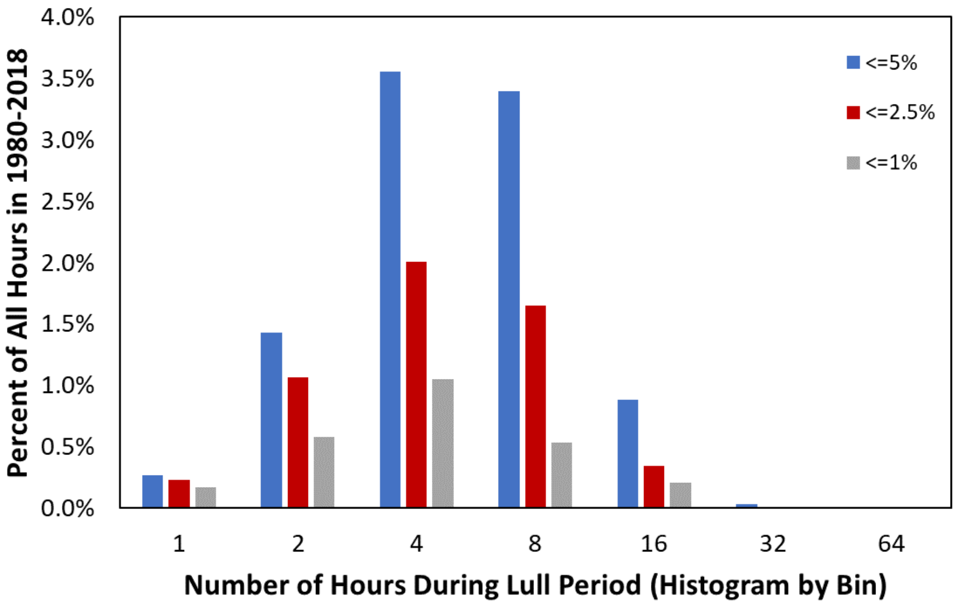


Table 13 shows the wholesale customer resources modeled.

Table 13. Wholesale Customer Resources

Unit Name	Capacity (MW)
WAPA_Allocation[11]	45
IREA_Victory Solar	12.8
IREA_Pioneer Solar	80
IREA_Hunter Solar	45
IREA_Kiowa Solar	54.5
Holy Cross_Arriba Wind	100
Holy Cross_Hunter Solar	30
Comanche 3	250

STORAGE DISPATCH

For the PSCo study, SERVM modeled the storage resources to be dispatched for economic arbitrage. In economic arbitrage operation, storage resources are scheduled using day-ahead forecasts of wind generation, solar generation, and load to be charged during low net load hours and dispatched during high net load hours. While the storage is dispatched in a manner to maximize economic arbitrage, that strategy is almost perfectly correlated with one that also preserves reliability. Additionally, SERVM allowed energy storage resources to provide ancillary services during emergency conditions without discharging which maximizes its reliability contributions.

The storage resources were modeled to be dispatched late in the dispatch stack only ahead of demand response resources. If generators fail unexpectedly or the actual renewable generation and load deviated significantly from the forecast, SERVM can dispatch the storage resources outside of the day-ahead schedule to preserve reliability, but it may affect the unit's availability in a later hour.

The modeled differences between batteries and pumped storage units were pumped storage units were modeled with a minimum discharge level instead of being able to operate at a baseline of 0 MW output like batteries. Similarly, charging pumped storage units was only allowed at a uniform charging level. The modeling respected the annual cycle limitations of the batteries and a 2-hour rest period between either fully charging or discharging the batteries.

DEMAND RESPONSE DISPATCH

The demand response resources listed in Table 11 above were given the dispatch constraints listed in Table 12 below. It was assumed that demand response could not serve ancillary services, and they were dispatched last in the dispatch stack.

[11] Based on historical data provided from PSCo for 2019-2020, daily average energy, total monthly energy, maximum dispatch, and schedule flow range entries were created for the WAPA hydro allocations of PSCo's Wholesale Customers. SERVM then optimally schedules hourly hydro energy while respecting these constraints. The total energy is the total amount of hydro that will be produced in a given month. This value cannot be greater than the total maximum hydro capacity multiplied by the number of hours in the month.

Table 12. PSCo Demand Response Dispatch Constraints

Interruption Action Window								
Program	Start Date	End Date	Start Hour (hr ending)	End Hour (hr ending)	Duration Single Event (Min)	Duration Single Event (Max)	Call Limits (Annual hours)	Call Limits (Annual Events)
AC Rewards	1-Jun	31-Aug	15	20	1	4	50	12
Critical Peak Pricing	1-Jan	31-Dec	13	20	4	4	60	15
ISOC160 Hour Customers	1-Jan	31-Dec	1	24	4	4	160	N/A
ISOC40 Hour Customers	1-Jan	31-Dec	1	24	4	4	40	N/A
ISOC80 Hour Customers	1-Jan	31-Dec	1	24	4	4	80	N/A
Peak Day Partners	1-Jan	31-Dec	1	24	1	6	None	None
Peak Partner Rewards	1-Jan	31-Dec	15	18	1	4	60	15
Savers Switch Residential	1-Jun	30-Sep	15	20	1	None	50	12

FUEL PRICES

Table 14 shows the fuel prices used in the study for PSCo and its neighboring power systems. The prices are based on data provided by PSCo. Since this study is focused on reliability, fuel prices are not a primary driver of the study results. Fuel prices are however necessary to create reasonable dispatch order in the simulations which can affect the reliability contribution of each generation resource.

Table 14. 2021 Fuel Prices

Fuel	2021 Price ($/mmBtu)
Coal	2.14
Oil	14.85
Natural Gas	3.36
Landfill Gas	2.10

UNIT OUTAGE DATA

Unlike typical production cost models, SERVM does not use an Equivalent Forced Outage Rate (EFOR) for each unit as an input. Instead, historical Generating Availability Data System (GADS) data events are entered in for each unit and SERVM randomly draws from these events to simulate the unit outages. The events are entered using the following variables:

Full Outage Modeling

Time-to-Repair Hours

Time-to-Fail-Hours

Partial Outage Modeling

Partial Outage Time-to-Repair Hours

Partial Outage Derate Percentage

Partial Outage Time-to-Fail Hours

Maintenance Outages

Maintenance Outage Rate entered as a % of time in a month that the unit will be on maintenance outage. SERVM uses this percentage and schedules the maintenance outages during off peak periods.

Planned Outages

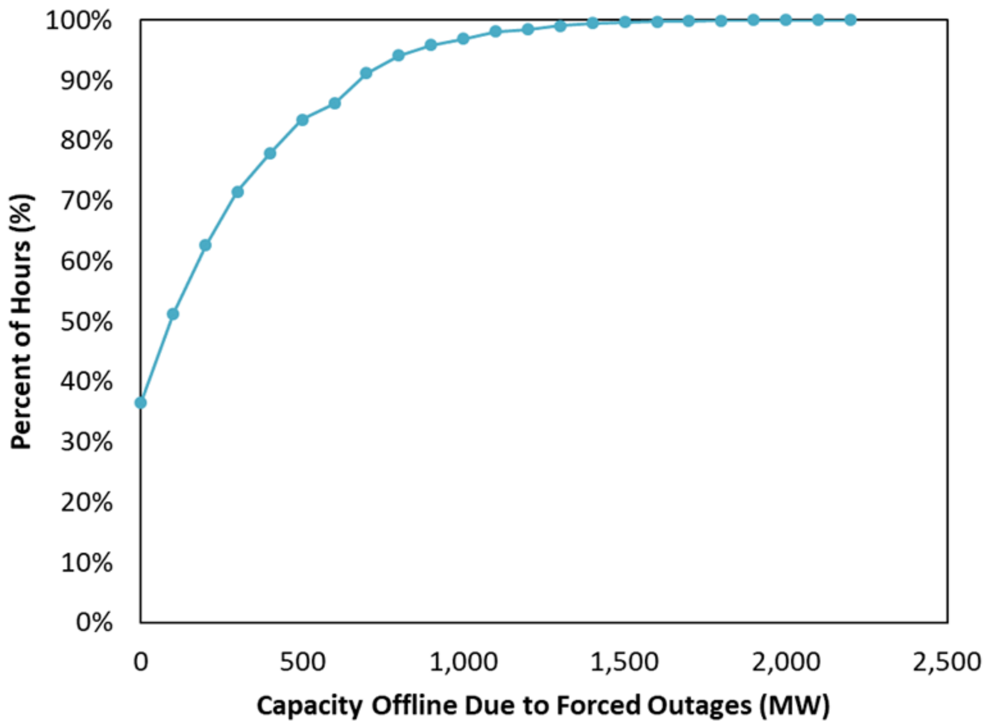
Specific time periods are entered for planned outages. Typically, these are performed during shoulder months.

As an example, assume that from 2014 to 2018 Cherokee CT5 had 13 full outages reported in the GADS data. The time-to-repair and time-to-fail between each event is calculated from the GADS data. These multiple time-to-repair and time-to-fail inputs are the distributions used by SERVM. Further, assume Cherokee CT5 is online in hour 1 of the simulation, SERVM will randomly draw a time-to-fail value from the distribution provided for full outages. The unit will run for that amount of time before failing. Next, the model will draw a time-to-repair value from the distribution and be on outage for that number of hours. When the repair is complete it will draw a new time-to-fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration. This more detailed modeling is important to capture the tails of the distribution that a simple convolution method would not capture.

Table A.1.1. in the Highly Confidential Appendix document shows each unit with its Modeled Equivalent Forced Outage Rate (EFOR). These reported values do not include maintenance outages which are also captured in the modeling. For neighboring regions, Astrapé used some of its in-house distributions to capture a reasonable EFOR in each external region. The average EFOR represented for external regions was 8.78%.

The most important aspect of unit performance modeling in resource adequacy studies is the cumulative MW offline distribution. Most service reliability problems are due to significant coincident outages. Figure 7 below shows the distribution of system outages as a percentage of time. The totals in this figure do not include maintenance outages or planned outages which are listed in Table A.2.1 in the Highly Confidential Appendix.

Figure 7. Cumulative Outages



EXTERNAL MARKET ASSISTANCE MODELING

The non-firm electric market plays a significant role in planning for resource adequacy. If multiple PSCo resources experience an outage and PSCo did not have access to surrounding non-firm energy, there is a high likelihood of firm load shed even during non-peak conditions. To capture a reasonable amount of non-firm energy assistance from surrounding neighbors, each neighbor was modeled at a target reliability of approximately 0.1 LOLE. Because only one tie away was modeled, neighboring systems do not have access to purchases from their neighbors not modeled in the study topology, so it was necessary to add additional capacity above the target reserve margin to get the external neighbors to the reliability standard. The 0.1 LOLE standard was chosen for neighbors even though other systems may not explicitly plan to it because it is the most common standard in the industry and because it results in a reasonable level of external assistance to PSCo. If neighbors were modeled at a standard less stringent than 0.1 LOLE, they may not frequently have excess energy to sell to neighbors and would rely on PSCo resources for reliability. Conversely, short-term excess resources in neighboring systems was not reflected because for planning decisions, only weather diversity and generator outage diversity benefit should be captured. Otherwise, PSCo may plan its future system to be reliant on neighboring generation resources that may be retired or otherwise unavailable. All study years assumed neighbors achieve approximately 0.1 LOLE despite rapidly changing resource mixes. However, the recent reliability events in California highlight the challenge of maintaining reliability when undergoing such a significant transition. While no conservatism was applied to market support within the SERVM modeling to consider the potential impact of increasing renewable penetration, changes in the market that may affect resource adequacy should be carefully monitored. This uncertainty is also part of the reason that Astrapé often recommends using a reserve margin range for a planning target because it recognizes that resources above the bare minimum required to meet 0.1 LOLE can obviate risks not taken into account in the Base Cases.

Table 15 outlines the transmission import limits between PSCo and each of its modeled external neighbors. These transmission limits reflect only the level of transmission available from neighboring systems to PSCo while the actual non-firm energy purchases will depend on the weather and generator outage diversity benefit with the neighboring systems. Several of the transmission connections between PSCo and its neighbors were modeled with a dynamic rather than static MW transfer rating based on historical available transfer capability on the transmission paths.

Historical hourly purchase data by counterparty was used to calibrate the modeled import and export amounts. Additionally, based on historical purchases during high load hours from 2015-2018, an aggregated import limit of 950 MW of non-firm energy purchases was imposed. 2019 was excluded from the external assistance calibration because PSCo made several short-term transmission purchases in 2019 for additional import capability.

Table 15. Transmission Capability

Region A	Region B	Import Distribution	Max Import Capability (MW)
PSCo	PACE	Static	0
PSCo	AZPS[1]	Dynamic	150
PSCo	PNM[1]	Dynamic	150
PSCo	SPP[2]	Dynamic	210
PSCo	WACM	Dynamic	60
PSCo	TRI	Dynamic	300
PSCo	PRPA	Static	300
PSCo	CSU	Static	350
PSCo	BHEC	Static	350

1. The Four Corner Transmission Path (AZPS & PNM) is modeled with a 150 MW aggregated limit based on recent historical performance
2. Represents the Lamar DC Tie. The dynamic import distribution reflects the historical outage rate of the Lamar DC Tie.

The Lamar DC Tie connects PSCo to SPP and has a 210 MW limit. The greater the wind generation output of Colorado Green and Twin Buttes the less the amount of non-firm energy PSCo can import from SPP. To capture this relationship, these two wind units were modeled in SPP, but their output was committed to PSCo. This limited the combined output of Colorado Green and Twin Buttes to below their total generation capability (237 MW compared to 210 MW); however, when these wind units are at maximum output there are no resource adequacy concerns for the PSCo system. The dynamic outage rate of the Lamar DC Tie was only applied to SPP generation to avoid impacting the reliability contribution of Colorado Green and Twin Buttes. The non-firm energy purchases made from SPP were capped at 190 MW based on historical purchase history and recognizing that non-firm energy from SPP delivered to PSCo must utilize the transmission rights of Colorado Green and Twin Buttes.

CONTINGENCY RESERVE

Astrapé modeled the contingency reserve required of the PSCo Balancing Authority Area (PSCo BAA) by the Northwest Power Pool. The contingency reserve is calculated in the model on a dynamic basis as a function of load, generation, transmission import paths to PSCo, and the generation output of the most severe single contingency (MSSC) within the PSCo BAA for any simulation hour.

Astrapé also modeled contingency reserve currently purchased from PSCo by Platte River Power Authority (PRPA). Because of this contingency reserve relationship, the model shed PSCo customer load when either the Platte River Power Authority system or the PSCo system were short contingency reserve which aligns with PSCo load shed procedures in this event. While PRPA was modeled at approximately 0.1 LOLE in every study year, PRPA's system is also transitioning to a high renewable system. It would require a complete study of PRPA's transitioning system through the study period to completely equalize its reliability effect on PSCo's System. This additional study was not completed, but its effect is captured in the target reserve margin range recommendation.

In addition to contingency reserves, Astrapé modeled the PSCo BAA ancillary services of regulation and flex reserve. Modeling these ancillary services in this study ensures the unit dispatch simulated within SERVM is reasonable for the amount of solar and wind generation in any simulation hour. Regulation and flex reserve reliably integrate renewable generation, but deficits of regulation or flex reserve did not contribute to load shed in the modeling. Only the deficit of contingency reserve contributed to firm load shed.

SIMULATION METHODOLOGY

Since most reliability events are high impact, low probability events, a large number of simulations must be considered. For PSCo, SERVM utilized 39 years of historical weather to create 39 years of load shapes and renewable profiles, 5 distribution points of economic load forecast error, and 10 iterations of unit outages for each case to represent the full distribution of realistic outcomes. The number of simulations for each case is 39 weather years * 5 economic load forecast errors * 10 unit outage iterations for a total of 1,950 simulations. The cases analyzed include the Base Cases for years 2021, 2023, 2026, and 2030 and several sensitivities of the Base Cases.

CASE PROBABILITIES

An example of probabilities given for each case is shown in Table 16. Each weather year is given equal probability and each weather year is multiplied by the probability of each economic load forecast error to calculate the case probability. Each of the case probabilities in Table 16 would also have 10 representations of unit outages to create the total 1,950 simulations.

Table 16. Case Probability Example

Weather Year	Weather Year Probability	Economic Load Forecast Error Multiplier	Economic Load Forecast Error Probability	Case Probability
1980	2.56%	0.96	7.26%	0.186%
1980	2.56%	0.98	24.10%	0.620%
1980	2.56%	1	37.28%	0.954%
1980	2.56%	1.02	24.10%	0.620%
1980	2.56%	1.04	7.26%	0.186%
1981	2.56%	0.96	7.26%	0.186%
1981	2.56%	0.98	24.10%	0.620%
1981	2.56%	1	37.28%	0.954%
1981	2.56%	1.02	24.10%	0.620%
1981	2.56%	1.04	7.26%	0.186%
1982	2.56%	0.96	7.26%	0.186%
1982	2.56%	0.98	24.10%	0.620%
1982	2.56%	1	37.28%	0.954%
1982	2.56%	1.04	24.10%	0.186%
1982	2.56%	1.04	7.26%	0.186%
…	…	…	…	…
2018	2.56%	1.04	7.26%	0.186%
			Total	1

RESERVE MARGIN DEFINITION

For this study, reserve margin is defined by the formula:

$$Reserve\ margin = \frac{resources - firm\ peak\ demand}{firm\ peak\ demand}$$

RELIABILITY METRIC

Across the industry, the 1 firm load shed event in 10 years is defined as 0.1 LOLE[12]. Loss of Load Expectation (LOLE) is defined in days per year and is calculated for each simulation. As outlined in the executive summary, the 1-day-in-10-year standard can also be interpreted as 24 hours of firm load shed over a 10-year period with the Loss of Load Hours (LOLH) metric. Traditionally, the 2.4 LOLH interpretation was used in studies that modeled systems without taking into account the reliability benefit of an interconnected transmission system. Given that this study modeled PSCo with non-firm energy purchases, the 0.1 LOLE metric will be used to determine the target reserve margin. Other reliability metrics are provided in this study report for informational purposes including LOLH and Expected Unserved Energy (EUE). Any hour that failed to maintain contingency reserve was a firm load shed event.

[12] https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf

PHYSICAL RELIABILITY RESULTS

Physical reliability of the electric power system is the measure of frequency, duration, and severity of firm load shed events. A firm load shed event refers to an instance where the utility must reduce load on the system by turning off the power to firm load customers due to the lack of generation resources. The most common resource adequacy standard in the industry today is the 1-day-in-10 standard. This standard allows for 1 firm load shed event every 10 years and is represented as an LOLE of 0.1 days per year. Figure 8 shows Loss of Load Expectation (LOLE) as a function of reserve margin. A 17.4% reserve margin provides PSCo 1-in-10 reliability for the Base Case in 2021.

Figure 8. LOLE Results

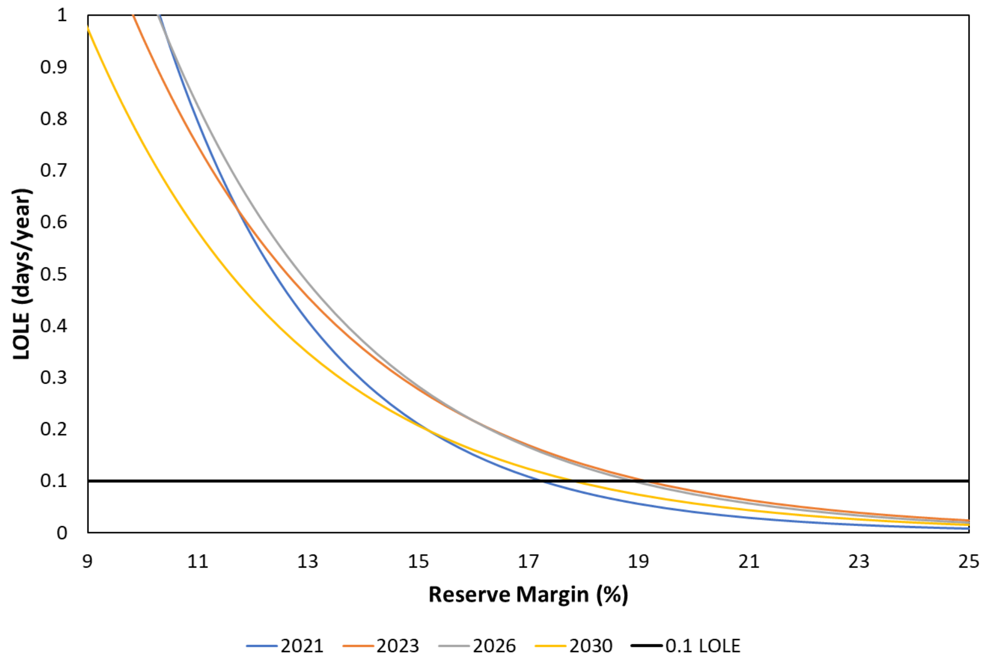


Table 17 shows LOLE and other physical reliability metrics by reserve margin for the 2021 Base Case. Loss of Load Hours (LOLH) is expressed in hours per year and Expected Unserved Energy (EUE) is expressed in MWh. The full table of results for the 2023, 2026, and 2030 Base Cases are located in the appendix.

Table 17. Physical Reliability Metrics: Base Case 2021

Reserve Margin (%)	Summer Resources (MW)	LOLE (days per year)	LOLH (hours per year)	EUE (MWh)
8%	7,197	0.86	2.55	542
9%	7,261	0.67	1.95	407
10%	7,324	0.53	1.50	306
11%	7,389	0.41	1.15	229
12%	7,454	0.32	0.88	172
13%	7519	0.25	0.67	129
14%	7,585	0.20	0.52	97
15%	7,652	0.15	0.40	73

16%	7,719	0.12	0.30	55
17%	7,787	0.11	0.27	47
18%	7,856	0.08	0.19	33
19%	7,925	0.06	0.13	23
20%	7,994	0.04	0.09	16
21%	8,064	0.03	0.07	11
22%	8,135	0.02	0.05	8
23%	8,207	0.01	0.03	5
24%	8,279	0.01	0.02	4
25%	8,352	0.01	0.02	3

Table 17 demonstrates the relationship between the level of reliability provided by the 0.1 LOLE standard compared to the 2.4 LOLH metric. The 0.1 LOLE level of reliability is met with a reserve margin of 17.4%, and the 2.4 LOLH level of reliability is met with a reserve margin of 8.2%. However, a reserve margin of 8.2% has a 0.74 LOLE. This means that the 2.4 LOLH interpretation of the reliability standard would expect firm load shed approximately 7 times in 10 years.

Table 18 shows the monthly LOLE distribution for each of the Base Case study years.

Table 18. Monthly LOLE Distribution

	Percentage of LOLE			
Month	**2021**	**2023**	**2026**	**2030**
1	0%	1%	3%	3%
2	0%	5%	4%	5%
3	0%	2%	0%	2%
4	0%	2%	0%	0%
5	0%	2%	0%	1%
6	21%	17%	20%	14%
7	49%	44%	36%	44%
8	21%	16%	21%	18%
9	7%	5%	5%	4%
10	0%	0%	2%	1%
11	0%	3%	4%	2%
12	1%	4%	4%	7%

As the results in the Table 18 demonstrate, there is a small but noticeable increase in winter and shoulder period reliability events. This is mainly caused by the shift of the PSCo portfolio to higher amounts of solar and wind resources. They provide more reliability value during the summer months than in the winter months and as the size of the renewable portfolio increases, PSCo will experience more reliability risk in the winter. The change between winter and summer reliability risk can be seen in Figures 9 and 10 below which displays the seasonal net load peak for each weather year in the 2021 and 2030 study year. By 2030, winter peaks make up a noticeable share of the overall highest net load peaks.

Figure 9. 2021 Seasonal Net Load Peaks

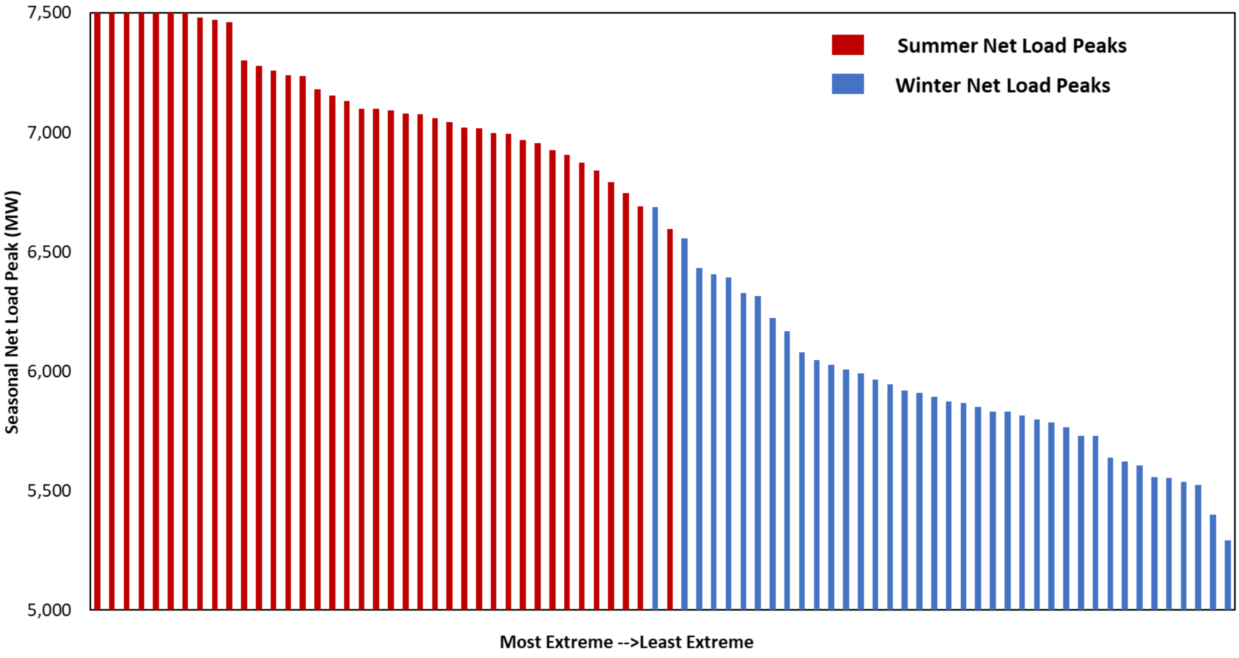
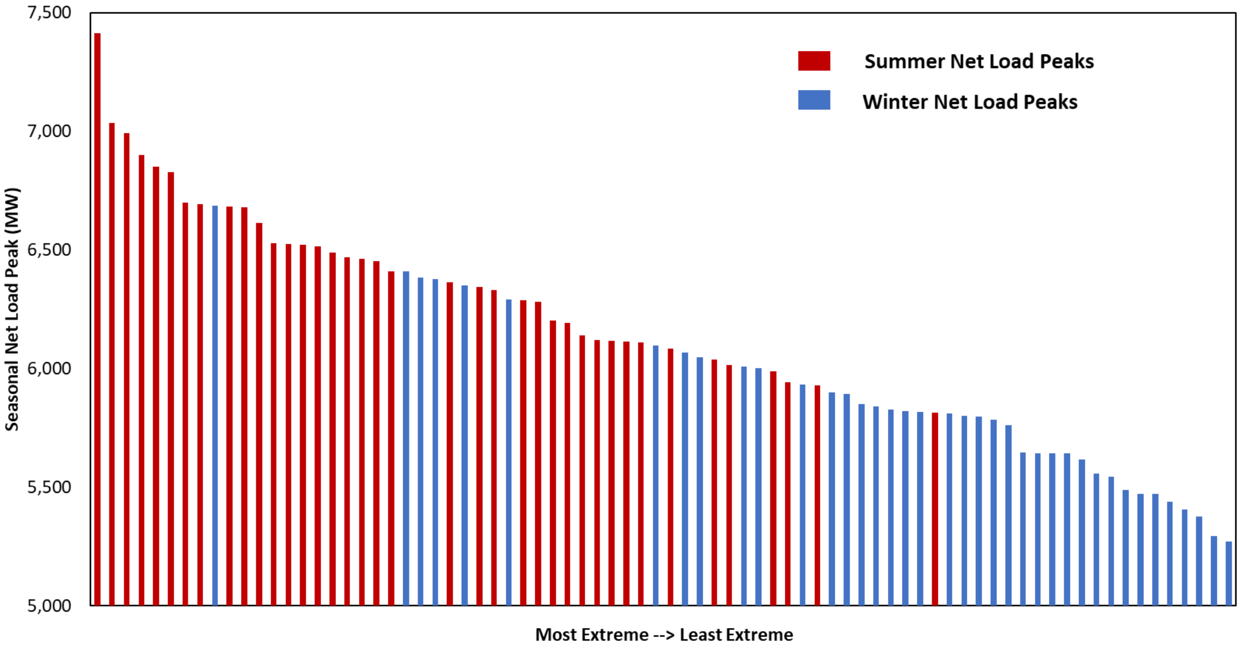


Figure 10. 2030 Seasonal Net Load Peaks



ADDITIONAL SENSITIVITY PHYSICAL RELIABILITY RESULTS

ISLAND SENSITIVITY

This sensitivity modeled PSCo as an island and assumed no external assistance from its neighbors. Table 19 shows LOLE and other physical reliability metrics by reserve margin for this sensitivity in 2021. The full table of results for the 2023, 2026, and 2030 study years are located in the appendix. As the table indicates, the target reserve margin increases by nearly 10% to 26.99%. This does not mean that PSCo can count on 10% of its peak load to be served by non-firm energy purchases, but rather from a wholistic perspective, the contribution of the electric market in off-peak and on-peak period allows PSCo to carry 10% lower planning reserve than it would need as an island. During both extreme hot and cold periods, the simulations indicated the ability to purchase less than 10% of its total load. When generator outages were high but weather conditions were mild, the non-firm electric market could provide more support.

Table 19. 2021 Island Sensitivity Physical Reliability Metrics

Reserve Margin (%)	Summer Resources (MW)	LOLE (days per year)	LOLH (hours per year)	EUE (MWh)
14%	7,598	2.50	8.24	2943
15%	7,661	1.94	6.16	2131
16%	7,725	1.50	4.61	1542
17%	7,789	1.16	3.45	1117
18%	7,854	0.90	2.58	808
19%	7,919	0.70	1.93	585
20%	7,985	0.54	1.44	424
21%	8,051	0.42	1.08	307
22%	8,118	0.33	0.81	222
23%	8,186	0.25	0.60	161
24%	8,254	0.20	0.45	116
25%	8,322	0.15	0.34	84
26%	8,391	0.12	0.25	61
27%	8,461	0.09	0.19	44
28%	8,531	0.07	0.14	32
29%	8,602	0.06	0.11	23
30%	8,674	0.04	0.08	17
31%	8,746	0.03	0.06	12

NO ECONOMIC LOAD FORECAST ERROR SENSITIVITY

The economic load forecast error distribution was removed in this sensitivity for the 2030 study year. The impact of the economic load forecast error is 0.55% as shown in Table 20 below.

Table 20. 2030 No Load Forecast Error Sensitivity Results

	0.1 LOLE Reserve Margin (%)
2030 Base Case	18.03%
2030 No LFE	17.48%

NO SPP IMPORT

In this sensitivity, the SPP import across the Lamar DC tie was removed for the 2030 study year. The maximum import capability of this DC tie is 210 MW and the difference in target reserve margin translated to MW is 119 MW as shown below in Table 21. A combination of SPP generation unavailability and transmission unavailability make the reliability contribution of SPP import less than the nominal rating of the DC tie. A portion of the transmission unavailability is associated with the PSCo wind resources which can affect the ability to import across the Lamar DC tie.

Table 21. 2030 No SPP Import Sensitivity Results

	0.1 LOLE Reserve Margin (%)	Benefit (MW) [13]
2030 Base Case	18.03%	-
2030 No Lamar Tie	19.67%	119

NO FOUR CORNERS TRANSMISSION IMPORT PATH SENSITIVITY

The Four Corners transmission import path was removed for the 2030 study year. PSCo's Four Corners transmission reservation is 188MW; however, the path rating is dynamically impacted by load and generation in the SW Colorado area. The difference in reserve margin target as a result of this sensitivity translated to MW is 97 MW as shown below in Table 22. A combination of generation unavailability and transmission unavailability make the reliability contribution of this import path less than its nominal rating.

Table 22. 2030 No Four Corners Path Sensitivity Results

	0.1 LOLE Reserve Margin (%)	Benefit (MW) [14]
2030 Base Case	18.03%	-
2030 No Four Corners Path	19.33%	97

INCREASED TRANSMISSION SENSITIVITIES

In these transmission sensitivities, the PSCO⇔PACE transmission capability was bi-directionally increased by 200 MW in 2030 in one scenario and 400 MW in another scenario. As the results in Table 23 below show, there is enough system (weather, load, and generator outages) diversity that the first

[13] 1.64% reserve margin multiplied by 7,269 MW of peak load = 119 MW.
[14] 1.33% reserve margin multiplied by 7,269 MW of peak load = 97 MW.

200 MW increase receives almost full credit but the second 200 MW addition receives diminishing credit of 51% [(289 MW – 187 MW)/200 MW].

Table 23. 2030 Increased Transmission Sensitivity Results

	0.1 LOLE Reserve Margin (%)	Benefit (MW)
2030 Base Case	18.03%	-
2030 Increased Transmission by 200 MW	15.46%	187
2030 Increased Transmission by 400 MW	14.06%	289

NON-FIRM FUEL SUPPLY SENSITIVITY

This sensitivity was simulated to examine the effects of potential fuel supply disruptions during cold weather conditions for the 2030 study year. To assess this risk, Plains End I and Plains End II were modeled on forced outage when the temperature was -5°F or below due to an assumed lack of natural gas supply. These units were chosen to assess this risk because they currently have non-firm fuel supply and have had fuel supply disruptions during cold weather in the past. The results are listed in Table 24 below. Since winter reliability risk is expected to become more frequent as solar and wind penetration increases, non-firm fuel supply risk may necessitate further analysis in future reliability studies.

Table 24. 2030 Non-Firm Fuel Supply Sensitivity Results

	0.1 LOLE Reserve Margin (%)
2030 Base Case	18.03%
2030 Non-Firm Gas Supply	18.52%

JDA MARKET RELIANCE SENSITIVITY

This sensitivity was performed to examine the contribution of the non-firm energy purchases from members of PSCo's JDA: BHEC, CSU, and PRPA. These zones were removed, and the 2030 study year was simulated. All other market connections were still included in the simulations. The results in Table 25 below show that PSCo can carry about a 1.3% lower reserve margin due to the market assistance from BHEC, CSU, and PRPA.

Table 25. 2030 JDA Market Reliance Sensitivity Results

	0.1 LOLE Reserve Margin (%)
2030 Base Case	18.03%
No Market Reliance	19.33%

250 MW FIRM ENERGY PURCHASE SENSITIVITY

This sensitivity was performed to examine the reliability contribution of 250 MW of firm energy purchases during the summer of 2023. Since no new capacity was added to the aggregated modeled area, the 250 MW firm energy purchase represents only a re-allocation of capacity. This re-allocation improves PSCo reliability, but some of the capacity purchased may have previously been available as a non-firm energy purchase in the modeled electric market. Thus, the benefit of the purchase is less than the nominal amount of capacity purchased. The results of the simulation demonstrate that a 250 MW firm energy purchase during the summer provides the equivalent reliability of 197 MW of new, fully dispatchable, year-round capacity.

SUMMARY

This study represents the culmination of efforts from PSCo and Astrapé staff to carefully analyze resource adequacy risks as PSCo anticipates continued evolution of its electric system. This study recommends changing the basis of the reserve margin target to the industry standard 0.1 LOLE from the 2.4 LOLH that was used in the prior study. While this standard is markedly more stringent, this study more rigorously assessed the ability of the market to provide support to PSCo. Astrapé applied this philosophy of modeling the distribution of expected conditions throughout all aspects of the study in order to give a true picture of the reliability needs of the PSCo system rather than applying conservatism to any of the inputs to the study. Therefore, the target reserve margin range of 18-20% represents a recommendation that is expected to efficiently produce reliability consistent with industry standards.

APPENDIX

APPENDIX A: PHYSICAL RELIABILITY RESULTS FOR ADDITIONAL STUDY YEARS

APPENDIX A.1: 2023 STUDY YEAR

Table A.1.1. Physical Reliability Metrics for 2023

Reserve Margin (%)	Summer Resources (MW)	LOLE (days per year)	LOLH (hours per year)	EUE (MWh)
8%	7,195	1.57	4.07	928
9%	7,257	1.23	3.13	703
10%	7,319	0.96	2.41	533
11%	7,382	0.75	1.86	404
12%	7,445	0.58	1.43	306
13%	7,509	0.45	1.10	232
14%	7,574	0.36	0.85	176
15%	7,639	0.28	0.65	133
16%	7,704	0.22	0.50	101
17%	7,770	0.17	0.39	77
18%	7,837	0.13	0.30	58
19%	7,904	0.10	0.23	44
20%	7,972	0.08	0.18	33
21%	8,040	0.06	0.14	25
22%	8,109	0.05	0.11	19
23%	8,179	0.04	0.08	15
24%	8,249	0.03	0.06	11
25%	8,320	0.02	0.05	8

Table A.1.2. Physical Reliability Metrics for 2023 Island

Reserve Margin (%)	Summer Resources (MW)	LOLE (days per year)	LOLH (hours per year)	EUE (MWh)
14%	7,574	3.11	9.01	3,264
15%	7,639	2.36	6.66	2,367
16%	7,704	1.78	4.92	1,716
17%	7,770	1.35	3.64	1,244
18%	7,837	1.02	2.69	902
19%	7,904	0.77	1.99	654
20%	7,972	0.59	1.47	474
21%	8,040	0.44	1.08	344
22%	8,109	0.34	0.80	249
23%	8,179	0.25	0.59	181
24%	8,249	0.19	0.44	131
25%	8,320	0.15	0.32	95
26%	8,391	0.11	0.24	69
27%	8,463	0.08	0.18	50

28%	8,536	0.06	0.13	36
29%	8,609	0.05	0.10	26
30%	8,683	0.04	0.07	19
31%	8,758	0.03	0.05	14

APPENDIX A.2: 2026 STUDY YEAR

Table A.2.1. Physical Reliability Metrics for 2026

Reserve Margin (%)	Summer Resources (MW)	LOLE (days per year)	LOLH (hours per year)	EUE (MWh)
8%	7,390	1.84	4.54	1,033
9%	7,455	1.41	3.39	754
10%	7,521	1.08	2.53	550
11%	7,588	0.83	1.89	401
12%	7,655	0.63	1.41	292
13%	7,723	0.48	1.05	213
14%	7,791	0.37	0.79	155
15%	7,860	0.28	0.59	113
16%	7,929	0.22	0.44	83
17%	7,999	0.17	0.33	60
18%	8,070	0.13	0.24	44
19%	8,141	0.10	0.18	32
20%	8,213	0.07	0.14	23
21%	8,286	0.06	0.10	17
22%	8,359	0.04	0.08	12
23%	8,433	0.03	0.06	9
24%	8,507	0.03	0.04	7
25%	8,583	0.02	0.03	5

Table A.2.2. Physical Reliability Metrics for 2026 Island

Reserve Margin (%)	Summer Resources (MW)	LOLE (days per year)	LOLH (hours per year)	EUE (MWh)
14%	7,814	3.83	9.91	3,419
15%	7,879	2.82	7.17	2,443
16%	7,944	2.08	5.19	1,746
17%	8,009	1.53	3.75	1,248
18%	8,076	1.13	2.72	892
19%	8,142	0.83	1.96	638
20%	8,210	0.61	1.42	456
21%	8,278	0.45	1.03	326
22%	8,346	0.33	0.74	233
23%	8,415	0.24	0.54	166

24%	8,485	0.18	0.39	119
25%	8,555	0.13	0.28	85
26%	8,626	0.10	0.20	61
27%	8,697	0.07	0.15	43
28%	8,769	0.05	0.11	31
29%	8,841	0.04	0.08	22
30%	8,915	0.03	0.06	16
31%	8,988	0.02	0.04	11

APPENDIX A.3: 2030 STUDY YEAR

Table A.3.1. Physical Reliability Metrics for 2030

Reserve Margin (%)	Summer Resources (MW)	LOLE (days per year)	LOLH (hours per year)	EUE (MWh)
8%	7,840	1.26	2.80	590
9%	7,912	0.98	2.13	437
10%	7,984	0.75	1.62	324
11%	8,056	0.58	1.23	240
12%	8,129	0.45	0.94	178
13%	8,203	0.35	0.71	132
14%	8,278	0.27	0.54	98
15%	8,353	0.21	0.41	72
16%	8,429	0.16	0.31	54
17%	8,506	0.12	0.24	40
18%	8,583	0.10	0.18	30
19%	8,661	0.07	0.14	22
20%	8,740	0.06	0.11	16
21%	8,819	0.04	0.08	12
22%	8,899	0.03	0.06	9
23%	8,980	0.03	0.05	7
24%	9,062	0.02	0.04	5
25%	9,144	0.02	0.03	4

Table A.3.2. Physical Reliability Metrics for 2030 Island

Reserve Margin (%)	Summer Resources (MW)	LOLE (days per year)	LOLH (hours per year)	EUE (MWh)
14%	8,281	1.40	3.26	1,124
15%	8,351	1.03	2.34	791
16%	8,422	0.76	1.68	557
17%	8,494	0.56	1.20	392
18%	8,566	0.41	0.86	276
19%	8,638	0.30	0.62	194
20%	8,711	0.22	0.45	137
21%	8,785	0.16	0.32	96

22%	8,859	0.12	0.23	68
23%	8,935	0.09	0.16	48
24%	9,010	0.07	0.12	34
25%	9,087	0.05	0.08	24
26%	9,164	0.04	0.06	17
27%	9,241	0.03	0.04	12
28%	9,319	0.02	0.03	8
29%	9,398	0.01	0.02	6
30%	9,478	0.01	0.02	4
31%	9,558	0.01	0.01	3

2020 Study of the Levels of Flex Reserve and Regulating Reserve Necessary for Reliable System Operation while Accommodating the Uncertainty of Wind and Solar Generation at Varying Levels of Installed Wind and Solar Generation Capacity within the Public Service Company of Colorado Balancing Area Authority

Public Service Company of Colorado

May 1, 2020

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Executive Summary

With its Electric Resource Planning process, Public Service Company of Colorado ("Company") meets the multiple objectives of (1) maintaining a safe, reliable electric system while (2) reducing carbon emissions by 80% from 2005 levels by 2030 and (3) keeping costs low for our customers. In order to achieve the 2030 carbon emissions mandate, the Company could replace a substantial portion of annual energy sourced from fossil-fueled generation with energy sourced from renewables such as wind and solar. Energy from wind and solar plants is dependent on the weather, which adds uncertainty to the economic generation dispatch process. Utilities address generation uncertainty by carrying reserves which can replace expected generation that is not available. This Study determines the volume of reserves necessary to maintain system reliability given the volume of wind and solar generation within the Company's Balancing Authority Area ("BAA"). In Phase 2 of the Electric Resource Planning process, the Company will evaluate various portfolios of generators to determine a preferred portfolio which meets the 2030 carbon reduction mandate while maintaining sufficient reserves to address the uncertainty of the portfolio of renewable generation and while keeping costs low for our customers.

A Technical Review Committee ("TRC") of experts in the integration of renewable generation into the electric system informed and reviewed the Company's Study. The Company used historic renewable generation data, where available, and synthesized generation profiles to represent future wind and solar generation additions.

The Company determined, and the TRC agreed, that the uncertainty of wind generation occurs during all seasons of the year and during all hours of the day. To determine the volume of Flex Reserve necessary to maintain reliable system dispatch given portfolios with varying volumes of wind generation, the Company determined the largest volume of wind generation that could be lost over a 30-minute period given the volume of wind generation at the start of the 30-minute ramp event. Table 1 shows the maximum Flex Reserve for the portfolios of installed wind generation capacity that were studied.

Table 1: Maximum Flex Reserve for wind portfolios

Portfolio	Base	Base + 500	Base + 1000	Base + 1500
Wind Capacity (MW)	4,962	5,462	5,962	6,462
Maximum Flex Reserve (MW)	1,391	1,494	1,553	1,691
Wind Gen at Max Flex (MW)	2,500	3,300	3,400	4,193

In contrast to wind generation, electric load and solar generation have moderately predictable patterns that are influenced by the season of year and the time of day. As such, Net Load (calculated as electric load minus solar generation) is also moderately predictable. Much of the movement in Net Load can be addressed through economic system dispatch based on Net Load forecasts and a relatively small volume of uncertainty must then be addressed through Regulating Reserve. Regulating Reserve is comprised of two components: (1) the Fast-Moving component addresses the minute-to-minute uncertainty in the Net Load; and the Following component addresses the 10-minute uncertainty in the Net Load trend. To determine the volume of Regulating Reserve necessary to maintain reliable system dispatch given

portfolios with varying volumes of solar generation, the Company first adjusted the data to account for the expected Net Load movement for the relevant season-of-year and hour-of-day. The Company then summed the largest values from the Fast-Moving and Following components of Regulating Reserve for each season-of-year and hour-of-day category after eliminating the top 5% of volumes from each component. Table 2 shows the range in hourly Regulating Reserve for the portfolios of installed solar generation capacity that were studied.

Table 2: Range of hourly Regulating Reserve for solar portfolios

Portfolio	Base	Base + 500	Base + 1000	Base + 1500	Base + 2000
Solar Capacity	**2,366 MW**	**2,866 MW**	**3,366 MW**	**3,866 MW**	**4,366 MW**
Minimum Regulating Reserve	**82 MW**	**82 MW**	**82 MW**	**82 MW**	**82 MW**
Maximum Regulating Reserve	**170 MW**	**192 MW**	**221 MW**	**250 MW**	**264 MW**

Introduction

Public Service Company of Colorado ("PSCo" or the "Company") must comply with reliability standards established and enforced by the North American Reliability Corporation ("NERC"). NERC BAL-002-3, the Disturbance Control Standard, requires that a Balancing Authority ("BA") carry sufficient Operating Reserve to respond to and recover from contingency events such as the loss of a large generator or transmission element. The Company realized that large, sustained loss-of-generation wind ramps could deplete the BA's Operating Reserve and potentially cause the Company to fail compliance with the Disturbance Control Standard. To address this concern, the Company studied the nature of large loss-of-generation wind ramps and developed a 30-minute Flexibility Reserve ("Flex Reserve") held in addition to Operating Reserve and designed specifically to address large wind ramps.

NERC Standard BAL-001-2, the Real Power Balancing Control Performance Standard, is intended to control the electric system interconnection frequency within defined limits and requires that Balancing Authorities comply with: (1) Control Performance Standard 1 ("CPS1"); and (2) the Balancing Authority ACE Limit ("BAAL") [1]. The Company has found that increasing levels of wind and solar generation has made compliance with NERC Standard BAL-001-2 more challenging. The Company addressed this concern by adding a 10-minute component to Flex Reserve and by studying the combined contribution of load and solar generation to the Fast-Moving and Following components of Regulating Reserve.

In CPUC Decision No. C17-0316, the Colorado Public Utilities Commission ("the Commission") ordered the Company to complete an updated Flex Reserve Study[2] to be filed with the Company's next Electric Resource Plan ("ERP") filing. The Commission also ordered the Company to conduct a backcast of

[1] The Balancing Authority balance between supply and demand is measure by its Area Control Error ("ACE"). Because supply and demand change unpredictably, there will often be a mismatch between them, resulting in non-zero ACE. CPS1 and BAAL establish the statistical boundaries for ACE magnitudes, ensuring that steady-state frequency is statistically bounded around its scheduled value.

[2] During the last ERP proceeding, the Company used Flex Reserve to address the uncertainty of wind generation. The Company believes, and the TRC agrees, that Flex Reserve should only address the uncertainty of wind generation and that Regulating Reserve should address the combined uncertainty of load and solar generation.

modeled wind data for verification and modification of the results to ensure the accuracy of or improve the accuracy of modeled wind data for use in the next Flex Reserve study and to work with the Commission's Trial Staff ("Staff") to form a panel of industry experts to help guide the updated study.

During the last ERP proceeding, Flex Reserve capacity was represented as a determinant for a reliability ceiling on renewable generation additions. The Company now believes that the Flex Reserve and Regulating Reserve requirements should not be used to limit the potential addition of renewable generation; but rather those requirements should be an input to production cost and capacity expansion models. For example, high volumes of renewable generation paired with sources of flexible, dispatchable generation capacity may result in lower cost model runs relative to the same volumes of renewable generation paired with generation capacity with less flexibility. Accordingly, this study will: (1) determine how much Flex Reserve is needed to address potential wind generation ramps; and (2) determine how much Regulating Reserve is needed to address solar uncertainty. The Resource Planning model runs will then determine what dispatchable generation capacity should be used to meet these requirements. While this study will determine the appropriate levels of reserve to reliably address resource uncertainty for wind (Flex Reserve) and load and resource uncertainty for solar (Regulating Reserve), the Company will continue to refer to the study as the Flex Reserve Study for ease of presentation.

Technical Review Committee

With the input and agreement of Staff, the Company invited the following individuals to participate on the Technical Review Committee ("TRC") for the Flex Reserve Study:

- Paul Denholm – Principal Energy Analyst at the National Renewable Energy Laboratory ("NREL")
- Debra Lew – Private Energy Consultant[3]
- Clyde Loutan – Principal, Renewable Energy Integration at the California ISO
- Julia Matevosyan – Lead Planning Engineer at the Electric Reliability Council of Texas
- Charlie Smith – Executive Director at the Energy Systems Integrations Group

All five individuals agreed to participate on the TRC and the TRC met four times.[4]

Technical Review Committee inputs into Flex Reserve Study

The TRC advised the Company on data sources, data validity, modeling approaches, improvements to modeling and modeling results analysis. Below is a listing of key TRC input into the study and study modeling:

1.) **Clarification between uncertainty[5] and variability**[6]: The Company previously claimed that Flex Reserve is a form of contingency reserve necessary to address the variability of wind generation

[3] Debra Lew is currently a private energy consultant. For several years she was a Senior Technical Director at General Electric Consulting and prior to working at GE she was a Senior Engineer at the National Renewable Energy Laboratory.
[4] The TRC met on October 4, 2018, June 3, 2019, November 20, 2019, and March 9, 2020.

rather than uncertainty. For example, the Company maintained that even if it had a perfect forecast of hourly wind generation, there can be considerable intra-hour generation variability that must be addressed. A TRC member noted that contingency reserves are typically carried to address *uncertainty* (i.e., sudden loss of transmission or generating unit or sudden restoration of demand). The Company concedes that Flex Reserve would not be necessary if, for instance, the Company had a perfect 5-minute wind generation forecast and, therefore, the Company and the TRC agree that Flex Reserve addresses wind generation uncertainty.

2.) **Time granularity of study data:** A TRC member expressed a concern that 5-minute data was not sufficiently granular to capture the uncertainty in solar generation. The Company proposed the use of 1-minute data and the TRC agreed that 1-minute data was sufficiently granular.

3.) **Preferred method to construct generation profiles for future wind plants:** A TRC member inquired how the study would assess renewable generation uncertainty with new wind additions that aren't in the same geographic location as existing resources, since that uncertainty is a direct driver of Flex Reserve need. The Company explained that while the Company cannot specify the location of new renewable resources, PSCo will disclose injection capability at various locations on the PSCo transmission system to prospective bidders during Phase 2 of the ERP process. The bidder is responsible for delivering generation to those injection points. The cost of building transmission to connect to the PSCo Bulk Power System is very expensive, so successful bidders typically bid projects located fairly closely to the injection points. The Company confirmed with the Xcel Energy Resource Planning and Transmission Planning groups that future injection capability is likely to be located along the recently built Pawnee-Daniels Park 345 kV backbone. Accordingly, much of capacity of future wind generation projects is likely to be located fairly closely to existing wind generation.

Given the assumption that future wind generation would likely be proximate to existing wind generation, the TRC members agreed that generation profiles for future wind projects could be constructed using wind speed data from existing wind plants with a time-offset to represent geographic diversity and scaled to account for differences in generation capacity between the existing and future plants. Further, the TRC acknowledged that weather model reanalysis data would not be available in the 1-minute granularity proposed for this study. The TRC requested that the Company perform a correlation analysis to compare wind speed model data against actual plant generation data as well as time-shifted empirical generation profiles against actual plant generation data to verify that the time-shifted empirical generation profiles are a reasonable proxy for future generation.

The Company gathered 5-minute wind speed and generation data from wind plants as well as from the NREL Wind Integration National Dataset ("WIND") Toolkit. Using these data sets, the Company compared actual wind generation profiles against synthesized profiles using:

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[5] Uncertainty typically means forecast error, but can also include unexpected events such as a generator trip.
[6] The generation output from renewable resources such as wind and solar is dependent on the weather, which is inherently variable. Periods of higher variability are harder to accurately predict than periods with low variability, thus uncertainty and variability are related, but separate concepts.

(1) wind speed data from a nearby wind plant converted to generation using an empirical power conversion from the target wind plant;
(2) wind generation data from a nearby wind plant scaled to match the generation capacity of the target wind plant;
(3) WIND Toolkit wind speeds for the target wind plant converted to generation using an empirical power curve from the target wind plant; and
(4) WIND Toolkit generation data for the target wind plant scaled to match the generation capacity of the target wind plant.

Based on the analysis of the results, the Company concluded that:

(1) The WIND Toolkit profiles were much less variable[7] than the wind speeds and generation data from the wind plants which makes the use of wind plant data superior for the purpose of the Flex Reserve Study;
(2) The WIND Toolkit profiles produced significantly more data points at very high generation levels which resulted in higher capacity factors than the actual plant data and proxy plant data;
(3) Profiles based on wind speed data from a plant within ~50 miles of the target plant were more highly correlated with actual plant generation than profiles based on the WIND Toolkit data;
(4) Based on the data, it seemed appropriate to use an offset of approximately one minute per mile of separation between an existing plant and a proposed plant when using data from the existing plant to create a profile for the proposed plant; and
(5) Using a power conversion appropriate for the proposed plant to convert wind speed data results in a more realistic capacity factor than using scaled generation data.

4.) **<u>The interaction between the uncertainty of load and the uncertainty of renewable generation</u>:** A TRC member questioned the Company's proposal to only study wind/solar generation ramps, as opposed to studying customer load net of renewable generation (hereafter referred to as *net load*). In the member's experience, with the addition of behind-the-meter solar generation, electric vehicle charging, and demand side management, net load exhibits greater variability than generation alone. Another member pointed out that forecast errors in load, wind, and solar could at times "pancake", and that a study of generation only might be less effective. The questioning TRC member further clarified that there can be offsetting diversity between load and renewable generation and that carrying reserves separately to address load uncertainty and renewable generation uncertainty may result in carrying excessive reserves. To address the TRC's concerns, the Company agreed to compare its current process of separately calculating load following reserve to address load uncertainty and Flex Reserve to address renewable generation uncertainty against a process of calculating Flex Reserve as a function of Net Load ramps which include the contribution of load, wind generation and solar generation.

[7] A less variable profile results in lower 30-minute ramp amplitudes than are actually experienced at the wind plants.

The Company gathered a years' worth of 5-minute load and renewable generation data and supplemented these data sets with a profile of behind-the-meter solar generation expected in 2023 in addition to all renewable generation approved in Phase 2 of the 2016 ERP as well as the solar facilities associated with the Renewable Connect program and the EVRAZ steel plant. Analysis of the data showed significantly higher levels of reserve required to cover the largest 30-minute and 10-minute Net Load (load minus wind and solar generation) ramps compared to the combined reserve necessary to cover (1) the largest 30-minute and 10-minute wind generation ramps and (2) a 10-minute Regulating Reserve to cover the combined uncertainty of load and solar generation. The Company concluded that there are predictably higher levels of load and solar variability during specific time-of-day and season-of-year combinations[8] whereas wind generation ramps can and do occur during any time-of-day and season-of-year combinations. Accordingly, the Company decided and the TRC approved basing the Flex Reserve requirement solely on wind generation data and basing the Regulating Reserve requirement on the combined uncertainty of load and solar generation data.

Backcast of the Expanded Study of 30-Minute Flex Reserve's modeled wind data using historical wind data

In the Company's previous Flex Reserve study, the Expanded Study of 30-Minute Flex Reserve on the Public Service Company of Colorado System[9] ("Expanded Flex Reserve Study"), the Company used wind speed data from geographically proximate wind plants to derive wind generation profiles for the Golden West and Rush Creek wind plants. The Commission ordered the Company to conduct a backcast of modeled wind data for verification and modification of the results to ensure the accuracy of or improve the accuracy of modeled wind data for use in the next Flex Reserve study.

Golden West

The Company gathered actual Golden West wind generation data and Cedar Point wind speed data for the time period June, 2016 through June, 2018 and performed a backcast and verification of the Golden West wind generation profile used in the Expanded Flex Reserve Study. In the Expanded Flex Reserve Study, Scenario 1 represented a portfolio with 2,566 MW of wind generation capacity; the capacity of the Company's wind generation portfolio including Golden West but not including Rush Creek. For the time period June, 2016 through June, 2018, the largest ramp for Scenario 1, which determines the maximum Flex Reserve requirement, was 824 MW when using Cedar Point wind speed data with a 5-hour offset compared to 850 MW when using actual Golden West generation data. For the same time period, the largest ramp for Scenario 1 was 855 MW when using Cedar Point wind speed data with a 1-hour offset.

The Company concludes that the Golden West profile derived from Cedar Point wind speed data with a 5-hour offset and converted to generation using an empirical Golden West power conversion, the methodology the Company used in the Expanded Flex Reserve Study, was a reasonably accurate proxy;

[8] For example, the evening lighting load ramp and coincident loss of solar generation during winter months make Hour Ending 16 and Hour Ending 17 much more variable and uncertain than the immediately preceding or succeeding hours.
[9] Hearing Exhibit 106, Attachment DTB-1, in Proceeding No. 16A-0396E.

however, a profile derived from Cedar Point wind speed data with a 1-hour offset would have been superior. Actual Golden West generation data was used for the current Flex Reserve Study.

Rush Creek

The Company gathered actual Rush Creek wind generation data as well as Limon 3 and Golden West wind speed data for the time period June, 2019 through February 19, 2020 and performed a backcast and verification of the Rush Creek wind generation profile used in the Expanded Flex Reserve Study. For this time period, the largest 30-minute loss-of-generation ramp based on metered Rush Creek generation was 422 MW. The largest 30-minute ramp for the Rush Creek generation profile based only on Limon 3 wind speed data was 525 MW and the largest combined 30-minute ramp for Rush Creek 1[10] generation based on Golden West wind speed data and Rush Creek 2[11] generation based on Limon 3 wind speed data was 425 MW.

The Company concludes that the Rush Creek wind generation profile based solely on Limon 3 wind speed data is inferior to a Rush Creek wind generation profile based on Golden West wind speed data for Rush Creek 1 generation and Limon 3 wind speed data for Rush Creek 2 generation. For time periods prior to December, 2018[12] in this Flex Reserve Study, the Company derived the Rush Creek 1 generation profile using Golden West wind speed data with a -20-minute offset[13] and the Rush Creek 2 generation profile using Limon 3 wind speed data with a +20-minute[14] offset.

Data for Flex Reserve and Regulating Reserve analysis

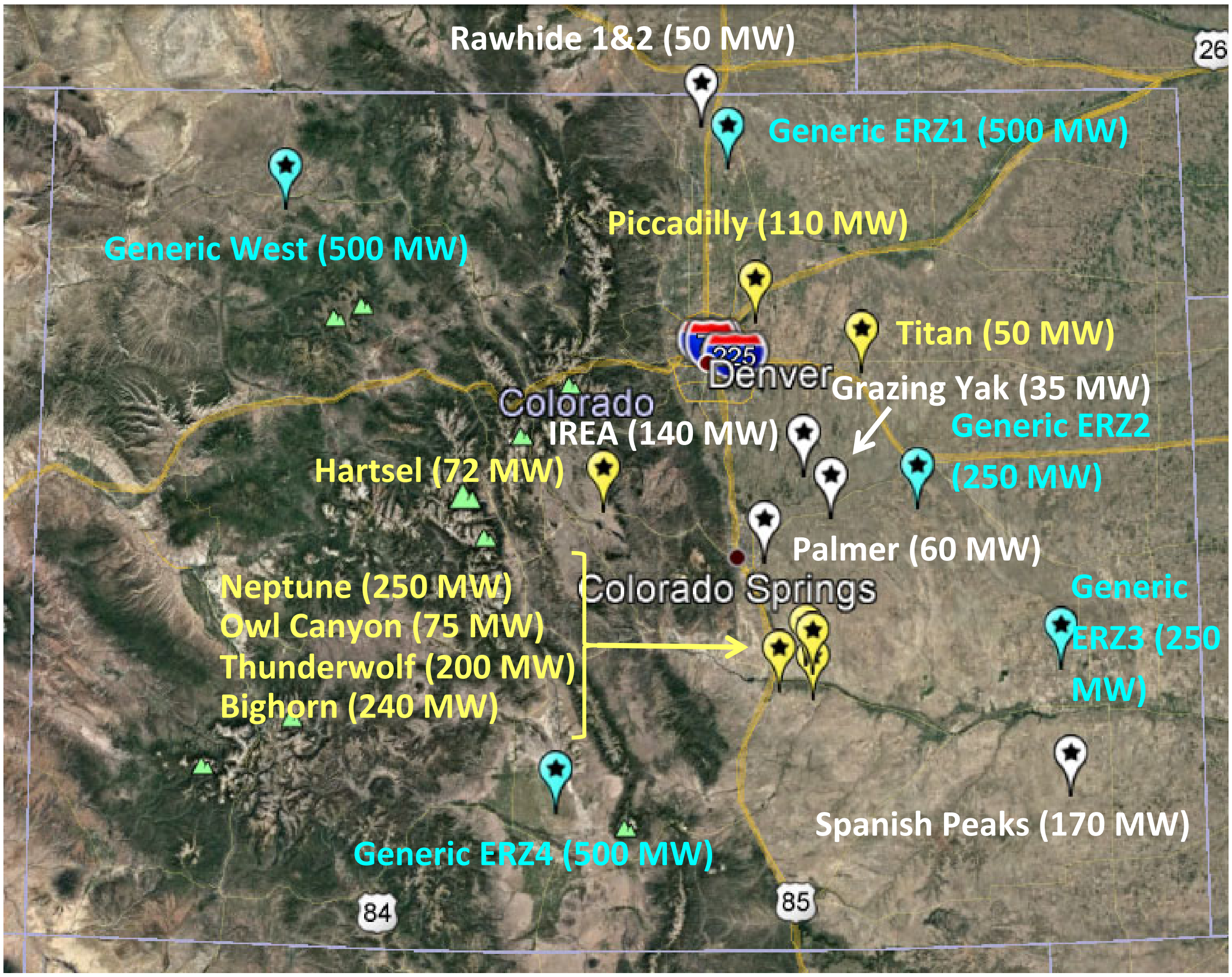
The Company gathered the following information to determine wind Flex Reserve and solar Regulating Reserve:

- 1-minute wind generation data for the time period November, 2015 through May, 2019.
- 1-minute wind speed data for the time period November, 2015 through May, 2019 for the following wind plants:
  - Cedar Creek 2
  - Limon 3
  - Golden West
  - Cedar Point
  - Colorado Green/Twin Buttes
- 1-minute solar generation data downscaled from 5-minute 2018[15] solar irradiance data from the NREL National Solar Radiation Database converted to solar generation using the NREL System Advisory Model (“SAM”). In Figure 1, the yellow data points represent solar plants controlled by

[10] Rush Creek 1 has generation capacity of 380 MW and is located approximately 20 miles NE of the Golden West wind plant.
[11] Rush Creek 2 has generation capacity of 220 MW and is located approximately 20 miles SE of Limon 3.
[12] Rush Creek had a Commercial Operation Date of December 9, 2018.
[13] The wind speed data from Golden West was assumed to occur 20 minutes earlier at Rush Creek 1.
[14] The wind speed data from Limon 3 was assumed to occur 20 minutes later at Rush Creek 2.
[15] Grant Buster from NREL provided the 1-minute solar generation data downscaled from the 5-minute 2018 solar irradiance data. 2018 is the only year for which NREL has 5-minute data granularity.

the Company[16], the white data points represent solar plants within the BAA not controlled by the Company, and the blue data points represent generic locations for potential future solar plants[17].

Figure 1: Solar plants with generation profiles derived from NREL irradiation data



- 1-minute distributed solar generation data from 2018 and scaled to 658 MW to represent the expected installed capacity of distributed solar generation in the Company's service territory in 2023.
- 1-minute data from 2018 for load and utility-scale solar generation controlled by the Company.

[16] Note that the solar plants controlled by the Company that are displayed on the map are those for which the Company constructed generation profiles using NREL irradiation data. There are other solar plants controlled by the Company which are not displayed and for which the Company used historic generation data.
[17] The Owl Canyon and Picadilly solar plants were selected projects under the Colorado Energy Plan; however, the Company did not reach a contractual agreement with these projects. Replacement projects are being considered under Proceeding 19A-0530E.

Wind Generation Profiles for Flex Reserve

The Company gathered or modeled the following information to determine wind Flex Reserve:

1. Base Case (Colorado Energy Plan portfolio + other wind generation within the BAA[18], 4,962 MW)
    a. Colorado Energy Plan wind generation portfolio (4,095 MW)
        i. Generation data from existing wind plants
        ii. Rush Creek 1 prior to COD – Golden West wind speed with -20 minute offset
        iii. Rush Creek 2 prior to COD – Limon 3 wind speed with +20 minute offset
        iv. Bronco Plains – Limon 3 wind speed with +20 minute offset
        v. Cheyenne Ridge – Limon 3 wind speed with +30 minute offset
        vi. Mountain Breeze – Cedar Creek 2 wind speed with -15 minute offset
    b. Round House (150 MW) – Cedar Creek 2 wind speed with -63 minute offset
    c. Peak View (61 MW) – Twin Buttes wind speed with -89 minute offset
    d. Busch Ranch 1&2 (88 MW) – Twin Buttes wind speed with -89 minute offset
    e. Crossing Trails (104 MW) – Limon 3 wind speed with -4 minute offset
    f. Spring Canyon 2&3 (63 MW) – Cedar Creek 2 wind speed with +37 minute offset
    g. Kit Carson (51 MW) – Limon 3 wind speed with +63 minute offset
    h. Carousel (150 MW) – Limon 3 wind speed with +63 minute offset
    i. Arriba (200 MW) – Limon 3 wind speed with +10 minute offset

Figure 2 shows the locations of the wind plants in the Base Case which have derived generation profiles and the existing wind plants from which wind speed data was used in the derivation. In Figure 2, the yellow data points represent wind plants controlled by the Company and white data points represent wind plants within the BAA that are not controlled by the Company.

[18] The Company has the responsibility for maintaining reliability for the entire Balancing Authority Area, so it must maintain sufficient Flex Reserve to cover the uncertainty of all wind generation within the BAA despite the fact that some of the wind generation is not controlled by the Company.

Figure 2: Base Case Wind Plants

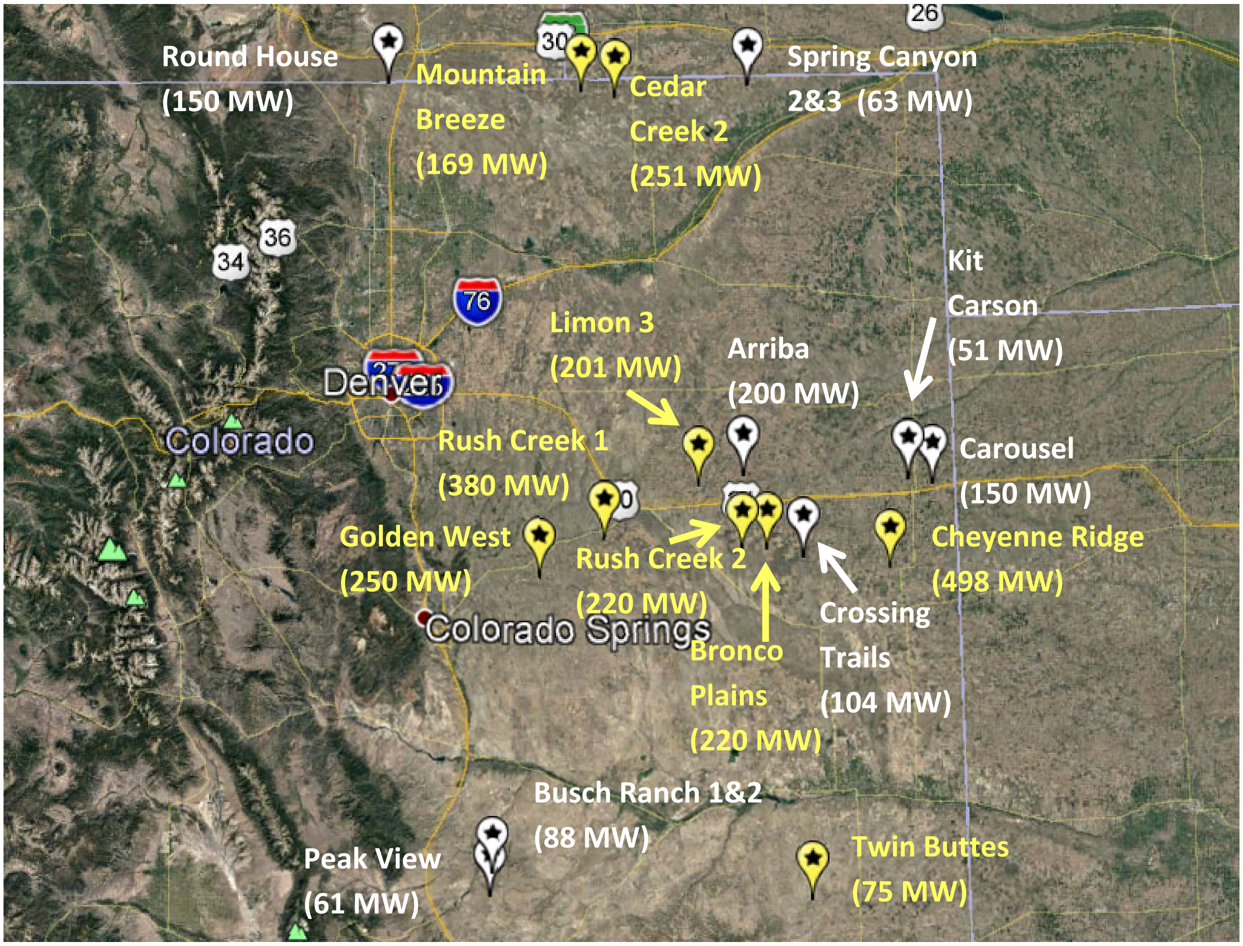
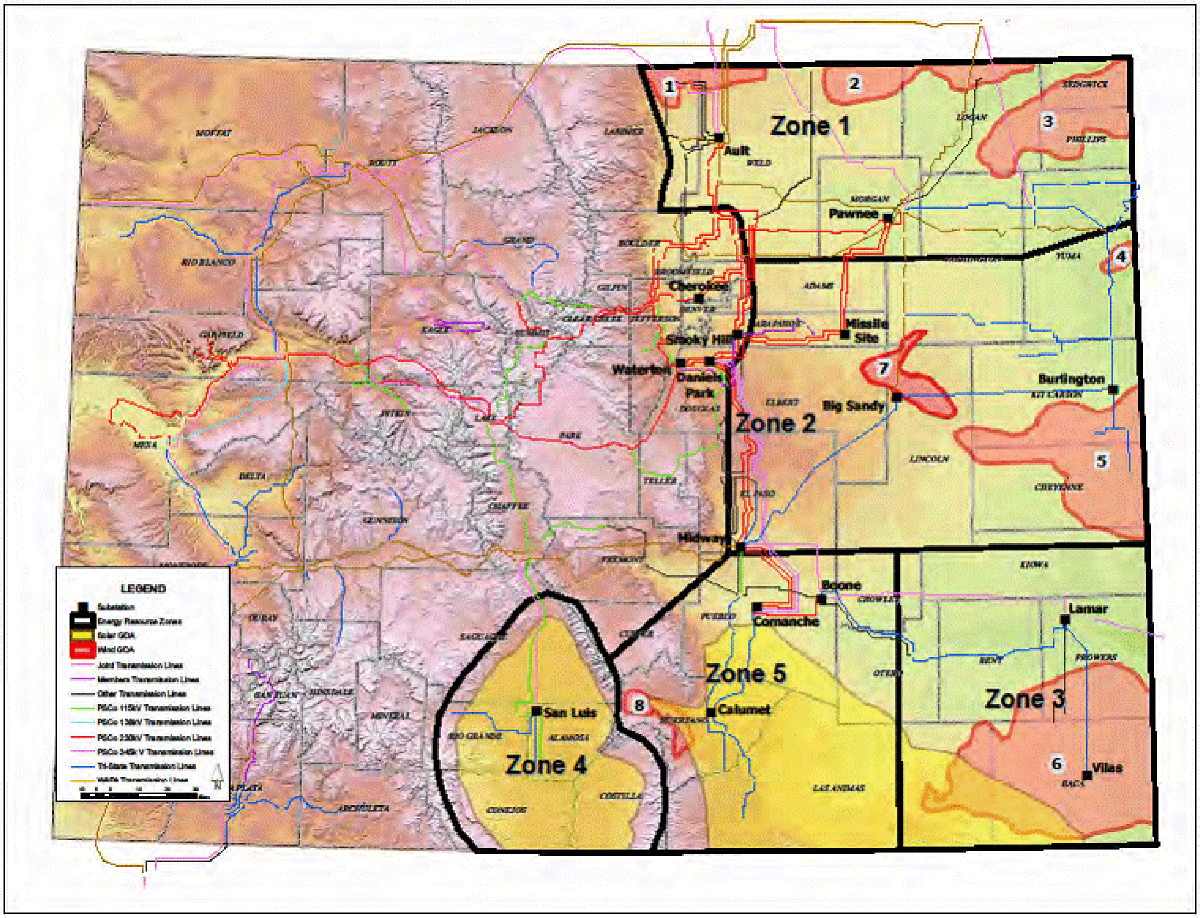


Figure 3: Energy Resource Zones



2. Base Case + 500 MW (5,462 MW)
    a. 500 MW Energy Resource Zone 1 ("ERZ1")
        i. 250 MW wind plant using Cedar Creek 2 wind speed with +15 minute offset
        ii. 250 MW wind plant using Cedar Creek 2 wind speed with +30 minute offset
    b. 500 MW Energy Resource Zone 2 ("ERZ2")
        i. 250 MW wind plant using Cedar Point wind speed with +15 minute offset
        ii. 250 MW wind plant using Golden West wind speed with +30 minute offset
    c. 500 MW Energy Resource Zone 3 ("ERZ3")
        i. 250 MW wind plant using Twin Buttes wind speed data with +15 minute offset
        ii. 250 MW wind plant using Twin Buttes wind speed data with +30 minute offset
3. Base Case + 1,000 MW (5,962 MW)
    a. ERZ1 + ERZ2
    b. ERZ2 + ERZ3
    c. ERZ1 + ERZ3
4. Base Case + 1,500 MW (6,462 MW)
    a. ERZ1 + ERZ2 + ERZ3

b. ERZ1 + ERZ2 + ERZ2
c. ERZ1 + ERZ3 + ERZ3
d. ERZ2 + ERZ1 + ERZ1
e. ERZ2 + ERZ3 + ERZ3
f. ERZ3 + ERZ1 + ERZ1
g. ERZ3 + ERZ2 + ERZ2

Load + Solar Generation Profiles for Regulating Reserve

The Company gathered the following information to determine solar Regulating Reserve:

1. Base Case (Colorado Energy Plan portfolio + other solar generation within the PSCo BAA, 2,366 MW)
    a. Colorado Energy Plan solar portfolio
        i. Generation data from existing plants (306 MW)
        ii. Hartsel Solar Plant (72 MW)
        iii. Neptune Solar Plant (250 MW)
        iv. ThunderWolf Solar Plant (200 MW)
        v. Owl Canyon Solar Plant (75 MW)
        vi. Picadilly Solar Plant (110 MW)
        vii. Bighorn Solar Plant (240 MW)
        viii. 2023 Distributed Solar generation (658 MW)
    b. Rawhide Solar Plants (50 MW)
    c. Palmer Solar Plant (60 MW)
    d. IREA Solar Plant (140 MW)
    e. Grazing Yak Solar Plant (35 MW)
    f. Spanish Peaks 1&2/San Isabel (170 MW)
2. 500 MW East (250 MW ERZ2 + 250 MW ERZ3), 2,866 MW
    a. 125 MW solar plant (ERZ2+ERZ3 profile with +3 minute offset[19])
    b. 125 MW solar plant (ERZ2+ERZ3 profile with +1 minute offset)
    c. 125 MW solar plant (ERZ2+ERZ3 profile with -1 minute offset)
    d. 125 MW solar plant (ERZ2+ERZ3 profile with -3 minute offset)
3. 500 MW ERZ1, 2,866 MW
    a. 125 MW solar plant (Generic ERZ1 profile with +3 minute offset)
    b. 125 MW solar plant (Generic ERZ1 profile with +1 minute offset)
    c. 125 MW solar plant (Generic ERZ1 profile with -1 minute offset)
    d. 125 MW solar plant (Generic ERZ1 profile with -3 minute offset)

[19] The Company analyzed 1-minute generation data from the Comanche solar plant and noted that the very largest 1-minute solar generation down ramps were almost always followed by a commensurately large up-ramp in the following minute. The Company concluded that these dramatic ramping events were the result of passing cloud shading on the PV panels and that applying a 2-minute time offset between the generation profiles for generic solar plants within an Energy Resource Zone would mimic sufficient geographic diversity to account for intermittent cloud cover.

4. 500 MW ERZ4, 2,866 MW
    a. 125 MW solar plant (Generic ERZ4 profile with +3 minute offset)
    b. 125 MW solar plant (Generic ERZ4 profile with +1 minute offset)
    c. 125 MW solar plant (Generic ERZ4 profile with -1 minute offset)
    d. 125 MW solar plant (Generic ERZ4 profile with -3 minute offset)
5. 500 MW West, 2,866 MW
    a. 125 MW solar plant (Generic West profile with +3 minute offset)
    b. 125 MW solar plant (Generic West profile with +1 minute offset)
    c. 125 MW solar plant (Generic West profile with -1 minute offset)
    d. 125 MW solar plant (Generic West profile with -3 minute offset)
6. ERZ4 + West (3,366 MW)
7. ERZ4 + West + ERZ1 (3,866 MW)
8. ERZ4 + West + ERZ1 + East (4,366 MW)

Flex Reserve Study Methodology

For each wind generation portfolio, the Company used the 1-minute data to determine the 30-minute change in wind generation given the starting level of generation. For each time period, the starting generation value was rounded up to the next 100 MW generation bin.

Example data:

- 2,015 MW at time T
- 1,970 MW at time T+1
- 1,695 MW at time T+30
- 1,705 MW at time T+31

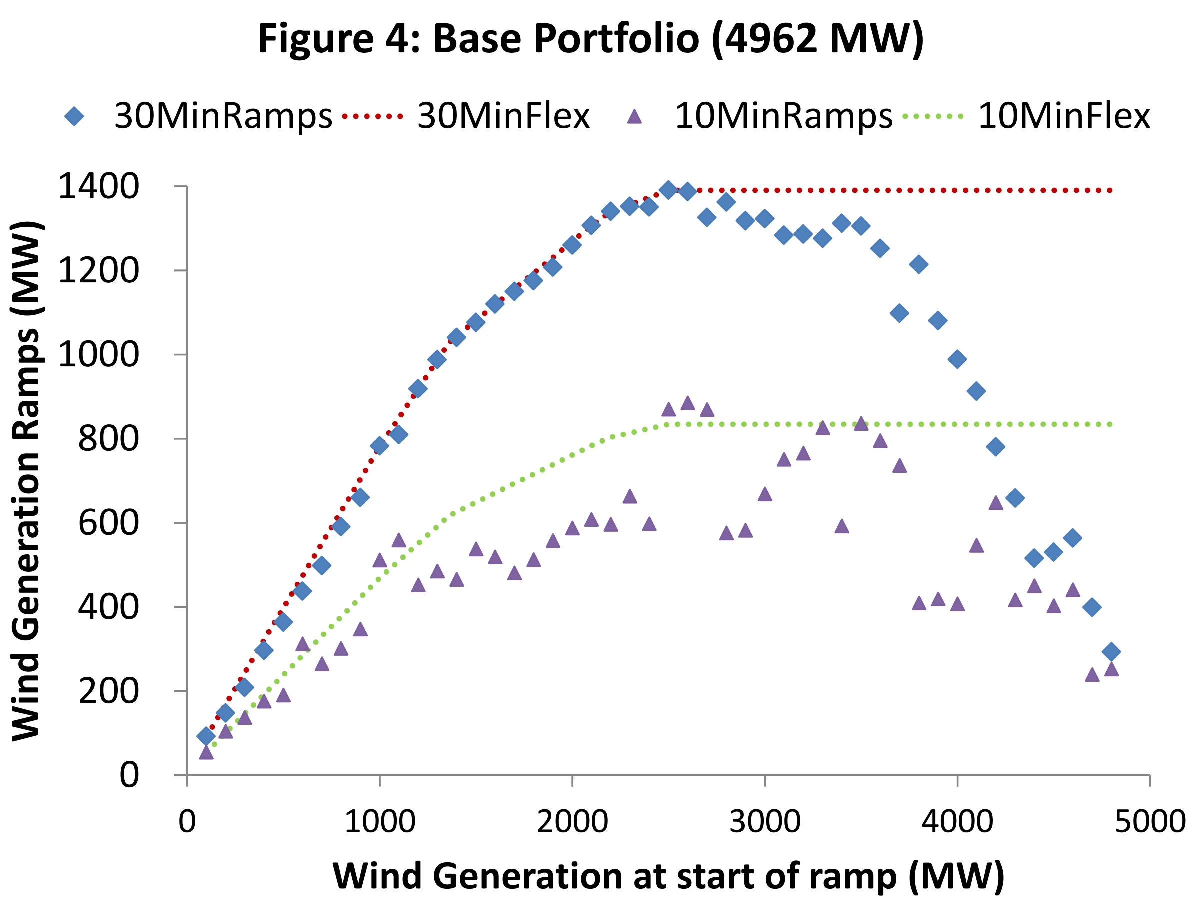
Using the example data above, time T is included in the 2,100 MW starting generation bin (2,015 MW rounded up to the next higher 100 MW generation bin) and has a 30-minute ramp of -320 MW (1,695 MW at time T+30 minus 2015 MW at time T). Time T+1 is included in the 2,000 MW starting generation bin and has a 30-minute ramp of -265 MW.

The Company created a scatterplot of the largest 30-minute loss of wind generation ramps for each 100 MW starting generation bin, and then used linear equations along the outer edge of the data points to create a Flex Reserve value that was at least as large as the largest ramp for each 100 MW starting generation bin.

For each portfolio, the Company also created a scatterplot of the largest 10-minute loss of wind generation ramps for each 100 MW starting generation bin, and then used linear equations along the outer edge of the data points to create a 10-minute Flex Reserve value that was at least as large as the largest 10-minute ramps for each 100 MW starting generation bin. On average across the portfolios for each 100 MW starting generation bin, the 10-minute Flex Reserve value was approximately 60% of the 30-minute Flex Reserve value. The Company decided to calculate the 10-minute Flex Reserve value as 60% of the 30-minute Flex Reserve value because: (1) 60% of the 30-minute Flex Reserve value is an accurate representation of the largest 10-minute wind ramps; and (2) 60% of the 30-minute Flex Reserve volume is easier to program in the Company’s Energy Management System than a completely separate set of formulas for the 30-minute and 10-minute components.

The final Flex Reserve requirements for the Base + 500 MW, Base + 1000 MW, and Base + 1500 MW profiles is the average of the largest 30-minute ramps, given the wind generation at the start of the ramp, from the underlying profiles. For example, the Base + 500 MW Flex Reserve value at 100 MW of wind generation is derived from the average of the largest ramps from the 100 MW generation bin from the Base + ERZ1, Base + ERZ2, and Base + ERZ3 profiles.

Figure 4 depicts the 30-minute ramps and the derived 30-minute Flex Reserve requirement for the Base Portfolio. The 10-minute Flex Reserve requirement is 60% of the 30-minute Flex Reserve requirement for each starting generation value. As can be seen in Figure 4, the 10-minute Flex Reserve requirement is representative of the largest 10-minute ramps realized for each 100 MW starting generation bin.

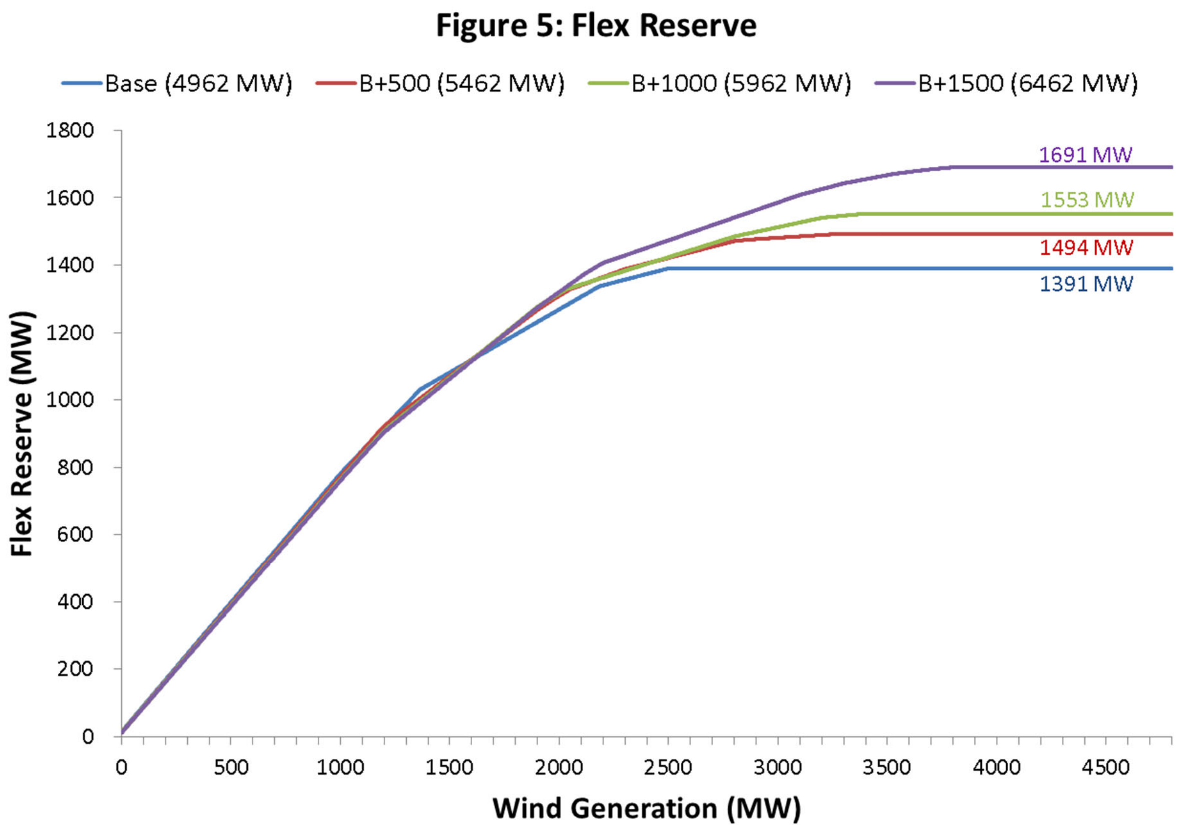


Flex Reserve Study Results

Table 3 lists the maximum levels of Flex Reserve required to account for wind resource uncertainty and to reliably operate the Company's system. Figure 5 shows the relationship between current levels of wind generation and the required volume of Flex Reserve for the various portfolios.

Table 3: Maximum 10-minute and 30-minute Flex Reserve requirements for wind generation portfolios

Portfolio	Maximum Flex Reserve	Maximum 10-min Flex Reserve
Base Case (4,962 MW)	1,391 MW	834 MW
Base + 500 (5,462 MW)	1,494 MW	896 MW
Base + 1000 (5,962 MW)	1,553 MW	932 MW
Base + 1500 (6,462 MW)	1,691 MW	1,015 MW



The Base Case portfolio represents the volume of wind generation within the BAA that has already been committed to by the Company and others. Note that the addition of 1.5 GW of wind generation results in virtually no increase in Flex Reserve for wind generation up to ~2000 MW and only a 300 MW increase in Flex Reserve at the highest levels of wind generation.

Regulating Reserve Study Methodology

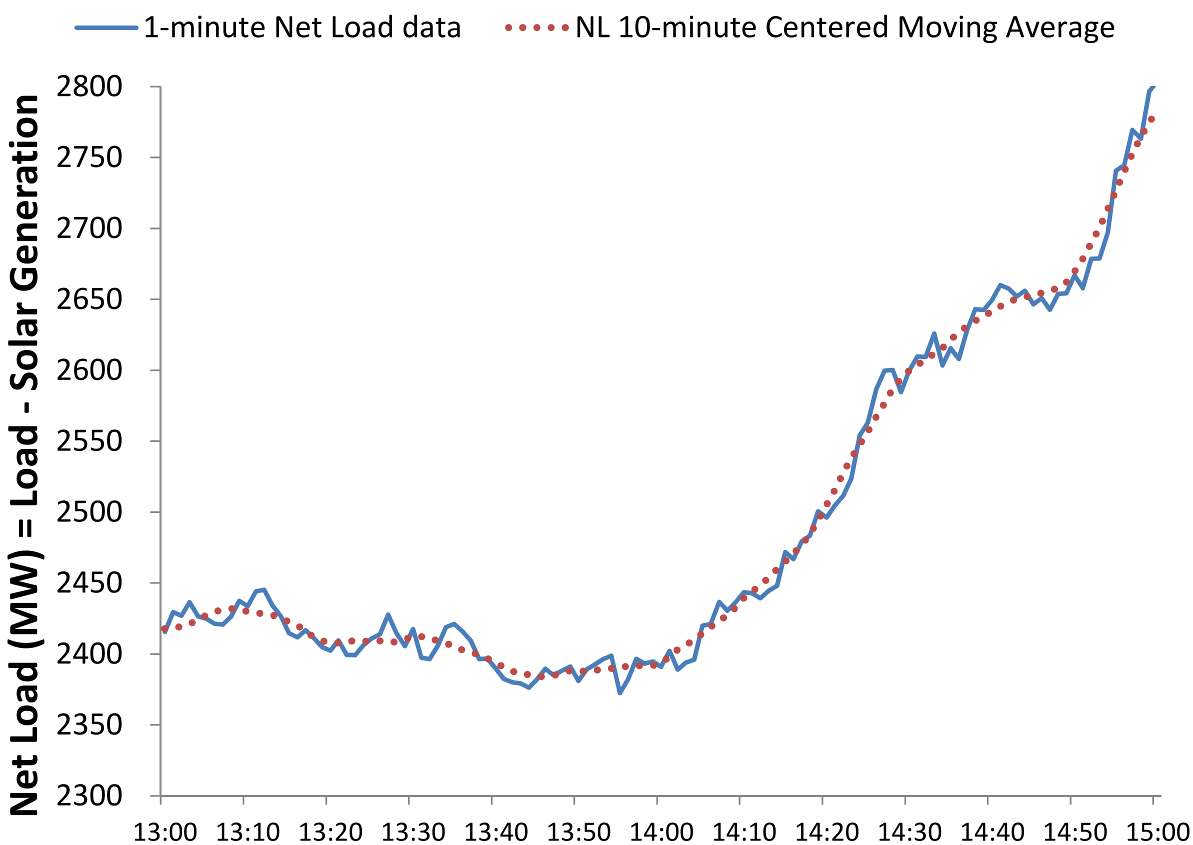
The methods for determining the incremental Regulating Reserve quantities required to support additional solar generation within the BAA are based on work performed by Brendan Kirby and Eric Hirst.[20] Regulating Reserve is comprised of Following and Fast-Moving components. The distinction

[20] Brendan Kirby and Eric Hirst, Pricing Ancillary Services so Customers Pay for What They Use, EPRI, (July, 2000) http://www.consultkirby.com/files/EPRI_Price_2000.PDF
And

between the Following component and the Fast-Moving component is the time period over which these fluctuations occur. The Fast-Moving component responds to one-minute load and generation fluctuations and the Following component responds to 10-minute changes.

For each solar generation portfolio, the Company used 1-minute load and solar generation data from 2018[21] to determine the 1-minute and 10-minute changes in load, solar generation, and Net Load[22]. In Figure 6, the blue line represents 1-minute Net Load data and the Net Load trend is represented by the pink dotted line which is calculated as the 10-minute centered moving average of the 1-minute Net Load data[23]. The uncertainty in the 10-minute Net Load trend, represented by the pink dotted line, is addressed by the Following component of Regulating Reserve and the minute-to-minute uncertainty is addressed by the Fast-Moving component.

Figure 6: Fast-moving and Following components



Brendan Kirby and Eric Hirst, *Customer-Specific Metrics for the Regulation and Load-following Ancillary Services*, Oak Ridge National Laboratory, https://certs.lbl.gov/sites/all/files/ornl-con-474.pdf.pdf (January, 2000).

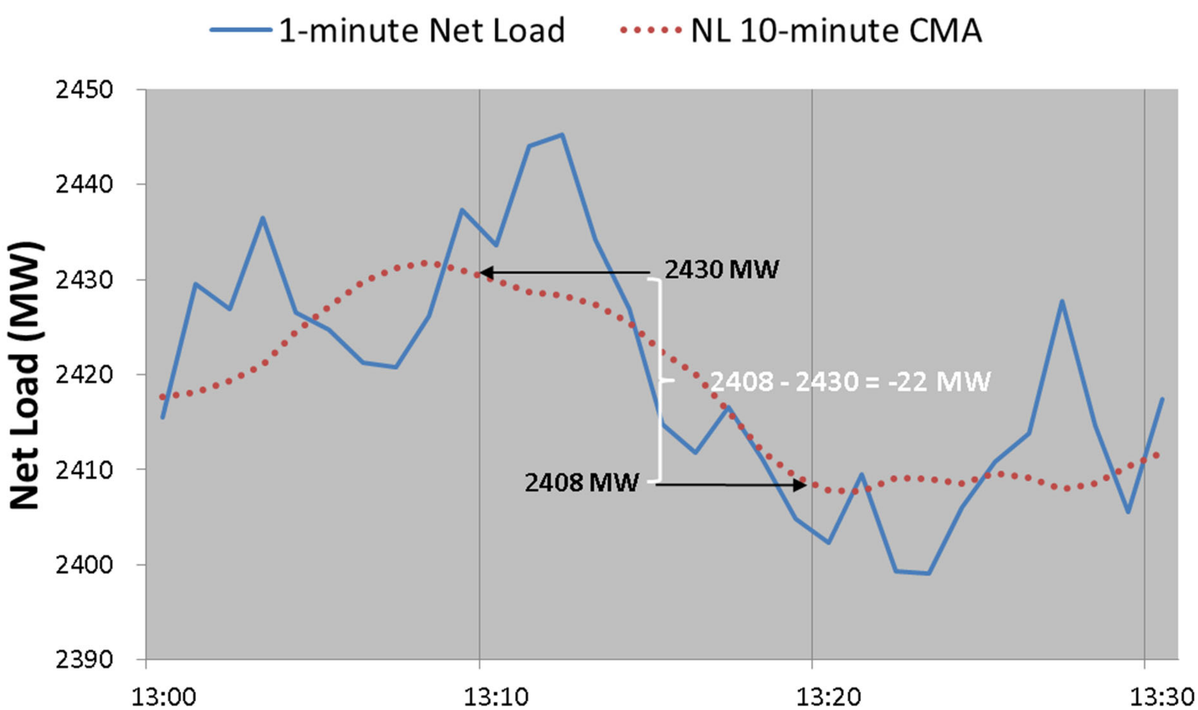
[21] NREL provided solar generation profiles for multiple locations in Colorado using 5-minute irradiance data that was downscaled to 1-minute granularity. The NREL irradiance dataset had 5-minute granularity only for 2018, so the Company limited the study period to 2018 to temporally match the solar generation change cases.

[22] In this case, Net Load is load less solar generation.

[23] For each 1-minute time period, the Company calculated the 10-minute centered moving average of the Net Load; in other words, the average of the eleven Net Load values centered on time T, from T-5 minutes to T+5 minutes.

Figure 7 shows the initial calculation of the Following component of Regulating Reserve. At time 13:10, the Net Load trend value is 2,430 MW, which is the average of the 1-minute Net Load values from 13:05 to 13:15, inclusive. At time 13:20, the Net Load trend value is 2,408 MW, which is the average of the 1-minute Net Load values from 13:15 to 13:25, inclusive. The maximum change in the Following component for this 10-minute time period from 13:10 to 13:20 is -22 MW, which the Company derived by subtracting the Net Load trend value at time 13:10 from the Net Load trend value at time 13:20. Note that there is a directional component to the calculation. If the Net Load is rising over the 10-minute time period, then the Following component is positive and if the Net Load is falling over the 10-minute time period, then the Following component is negative. Also note that the Company calculated the Following component for each clock 10-minute period; however, the maximum and minimum Net Load trend value does not need to coincide with the beginning or end of the clock 10-minute period. For example, during the clock 10-minute period from 13:00 to 13:10 in Figure 7, the maximum Net Load trend value occurs at 13:08.

Figure 7: Following component calculation



The Company divided the year into three seasons: summer, winter, and shoulder. The summer season includes the months June through September, the winter season includes the months November through February, and the shoulder season includes the remaining months of March through May and October. As stated earlier, the Company sorted the data by season-of-year and hour-of-day. For each season-of-year and hour-of-day data category, there were approximately 732 data values (~122 days per season * 6 clock 10-minute periods per hour = 732 data points per season-of-year and hour-of-day category).

The Company covers a significant portion of the Following component of Regulating Reserve with economic dispatch based on the forecasts of load and renewable generation. The Company determined the economic dispatch portion of Following by taking the average of the ~732 Following values for each season-of-year and hour-of-day category. The Company subtracted this averaged value from each Following value in the season-of-year and hour-of-day category. Then the Company excluded the top 5% of data values for each category (732 data points * 0.05 = ~37 largest Following values excluded for each season-of-year and hour-of-day category). The remaining largest Following value is the Following component of Regulating Reserve for that season-of-year and hour-of-day category.

The Company used the same process to determine the Following component of Regulating Reserve for load and solar generation separately. For example, for hour ending 8 during the Winter season for the Base Portfolio the Following component of Regulating Reserve based solely on load data is 59 MW[24], the Following component based solely on solar generation data is 65 MW, and the Following component based on Net Load data (load data net of solar generation) is 110 MW. Note that there is offsetting uncertainty in the load and solar generation data resulting in a lower reserve requirement for the Net Load than would be realized by summing the Following reserve requirements for load and solar generation calculated separately.

The Fast-Moving component of Regulating Reserve is calculated for each minute by taking the difference between the 1-minute Net Load value and the Net Load trend calculated as the 10-minute centered moving average value. Note that the Fast-Moving component can be positive if the 1-minute Net Load value is larger than the Net Load trend value or negative if the 1-minute Net Load value is smaller than the Net Load trend value. The Company excluded the top 5% of data values for each season-of-year and hour-of-day category. The remaining largest Fast-Moving value is the Fast-Moving component of Regulating Reserve for that season-of-year and hour-of-day category. The Company used the same process to determine the Fast-Moving component of Regulating Reserve for load and solar generation separately. For example, for hour ending 8 during the Winter season for the Base Portfolio the Fast-Moving component of Regulating Reserve based solely on load data is 33 MW, the Following component based solely on solar generation data is 14 MW, and the Following component based on Net Load data (load data net of solar generation) is 35 MW.

<u>A Fair Allocation to Solar Generation of the Regulating Reserve Requirement</u>

The Company's intent is to determine the incremental Regulating Reserve required supporting various volumes of future solar generation. Assuming no correlation between the uncertainty of load and solar generators allows us to use the square root of the sum of the squares approach to determine the contribution from the two separate contributors of the Following component of Regulating Reserves. Similarly, an assumption of non-correlation allows the same approach to determine the relative contribution from load and solar generators to the Fast-Moving component of Regulating Reserves.

While working at Oak Ridge National Laboratory, Brendan Kirby developed a formula[25] for the fair allocation of reserves that is independent of the correlation between the separate contributors to the

[24] 59 MW represents the largest load Following value after eliminating the top 5% of load Following values for that season-of-year and time-of-day.

[25] $$\sigma_{i\_allocation} = \frac{\left(\sigma_{Total}^2 + \sigma_i^2 - \sigma_{Total-i}^2\right)}{2 * \sigma_{Total}}$$

Regulating Reserve components of Following and Fast-Moving. We used a variation[26] of the Kirby formula to calculate an allocation for the Following and Fast-Moving components of Regulation Reserves.

For example, for the Following component of the Regulating Reserves during HE8 in the Winter season, we calculated the allocation to solar generation Following by summing the square of the 95th percentile for solar generation Following values (65 MW) and the square of the 95th percentile for Net Load Following (110 MW) and then subtracting the square of the 95th percentile for load Following (59 MW). This value was then divided by twice the value of the 95th percentile for Net Load Following (2 * 110 = 220). Specifically for HE 8 during the Winter season:

Solar generation Following share = $[(65)^2 + (110)^2 - (59)^2] / (2 * 110) = 58.4$ MW

Regulating Reserve Study Results

Table 4 shows the solar contribution to hourly Regulating Reserve values for the Base Portfolio by season-of-year and hour-of-day. The Base Portfolio includes all solar generation included in the Colorado Energy Plan plus other solar generation within the PSCo BAA with dispatch not controlled by the Company. The hourly solar Regulating Reserve volume is the sum of the solar allocation of the Fast-Moving and Following components. For example, the hourly solar Regulating Reserve volume of 63.1 MW during HE8 in the Winter season is comprised of 4.7 MW from the Fast-Moving component and 58.4 MW from the Following component. Figure 8 is a graph of the data found in Table 4.

[26] We used 95th percentile values rather than standard deviations. Approximately 95% of values fall within two standard deviations ("σ") of the mean. Eliminating the top and bottom 2.5% of data from the data set would approximate the application of two standard deviations. Some participants in the TRC felt that it would be more appropriate to eliminate the largest 5% of Regulating Reserve values rather than the largest 2.5% of values, so the Company used the standard of the 95th percentile of the values.

Table 4: Solar Contribution to Regulating Reserve for Base Portfolio (2,366 MW)									
	Winter			Shoulder			Summer		
MST	Fast-moving	Following	Regulating	Fast-moving	Following	Regulating	Fast-moving	Following	Regulating
HE1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE5	0.0	0.0	0.0	0.0	1.0	1.0	0.0	1.1	1.1
HE6	0.0	0.0	0.0	0.3	23.2	23.5	0.6	45.5	46.0
HE7	0.0	4.0	4.0	9.2	73.5	82.7	10.3	65.9	76.2
HE8	4.7	58.4	63.1	17.9	89.9	107.7	14.4	62.8	77.2
HE9	17.2	86.9	104.0	15.8	62.2	78.0	11.9	49.4	61.3
HE10	12.3	51.5	63.7	12.9	52.9	65.8	9.2	35.9	45.1
HE11	8.6	30.8	39.3	10.1	37.8	47.8	7.5	31.9	39.5
HE12	3.0	19.8	22.9	8.7	40.5	49.1	7.8	30.8	38.6
HE13	4.6	30.7	35.2	11.6	45.8	57.4	12.0	59.1	71.1
HE14	8.1	37.5	45.6	14.2	64.0	78.2	14.8	82.6	97.4
HE15	10.9	54.0	64.9	19.3	76.2	95.5	19.2	82.0	101.2
HE16	12.0	59.9	71.9	21.6	84.1	105.7	20.4	92.2	112.6
HE17	2.4	44.9	47.3	16.1	80.4	96.5	18.8	81.2	100.0
HE18	0.0	66.7	66.7	6.5	62.4	68.9	11.1	45.1	56.1
HE19	0.0	1.0	1.0	0.1	53.0	53.2	0.6	28.7	29.3
HE20	0.0	0.0	0.0	0.0	1.0	1.0	0.0	28.4	28.4
HE21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Figure 8: Base Portfolio (2366 MW) Solar Regulating Reserve

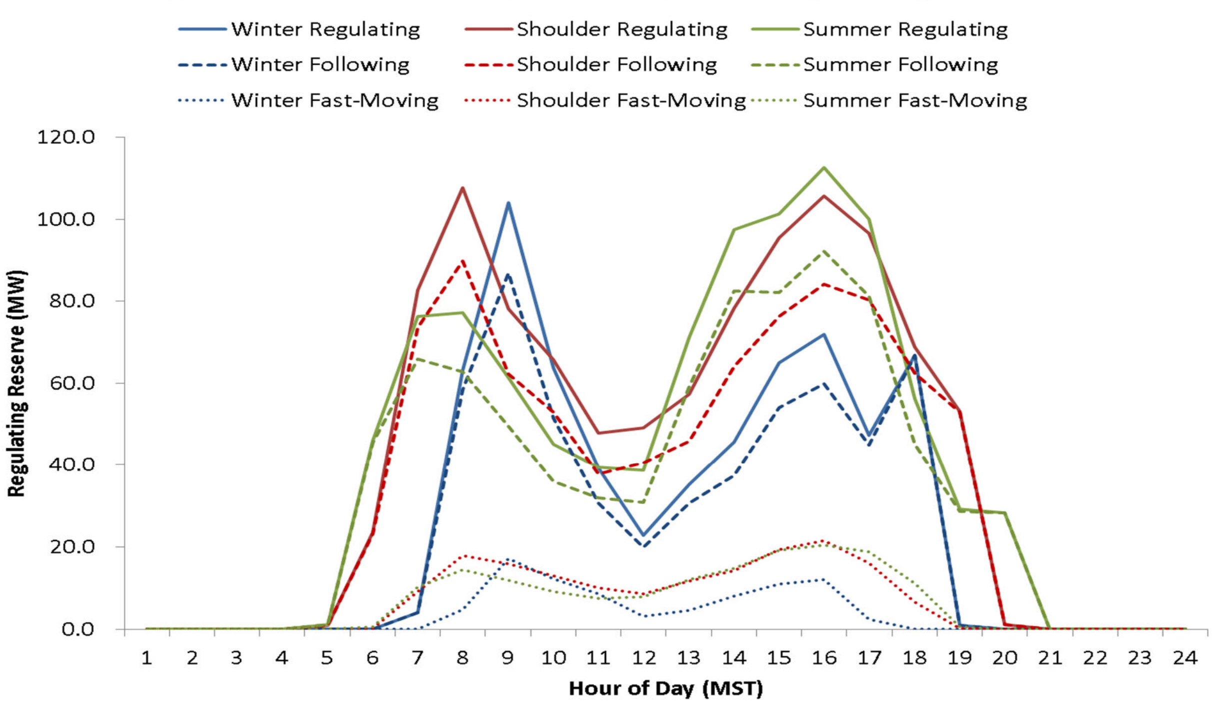


Table 5 shows the solar generation allocation of the hourly Regulating Reserve values for the Base + 500 Portfolio by season-of-year and hour-of-day. The Company studied four separate Base + 500 Portfolios by adding to the Base Portfolio 500 MW of generic solar generation resource in either the West, ERZ1, East, or ERZ4. The values in Table 5 are the average of the values for the four separate Base + 500 portfolios.

Table 6 shows the solar generation allocation of the hourly Regulating Reserve values for the Base + 1,000 Portfolio by season-of-year and hour-of-day. The Base + 1,000 Portfolio added to the Base Portfolio 500 MW each of generic solar generation resource from the West and ERZ4.

Table 7 shows the solar generation allocation of the hourly Regulating Reserve values for the Base + 1,500 Portfolio by season-of-year and hour-of-day. The Base + 1,500 Portfolio added to the Base Portfolio 500 MW each of generic solar generation resource from the West, ERZ4, and ERZ1.

Table 8 shows the solar generation allocation of the hourly Regulating Reserve values for the Base + 2,000 Portfolio by season-of-year and hour-of-day. The Base + 2,000 Portfolio added to the Base Portfolio 500 MW each of generic solar generation resource from the West, ERZ4, ERZ1, and East.

Figures 9-11 are graphs of the solar generation allocation of the Regulating Reserve values for the Winter, Shoulder, and Summer seasons, respectively, for each of the following portfolios: Base (2,366 MW), Base + 500 (2,866 MW), Base + 1,000 (3,366 MW), Base + 1,500 (3,866 MW), and Base + 2,000 (4,366 MW).

Table 5: Solar Allocation of Regulating Reserve for Base + 500 = 2,866 MW solar

	Winter			Shoulder			Summer		
MST	Fast-moving	Following	Regulating	Fast-moving	Following	Regulating	Fast-moving	Following	Regulating
HE1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE5	0.0	0.0	0.0	0.0	1.0	1.0	0.0	1.6	1.6
HE6	0.0	0.0	0.0	0.4	30.4	30.7	1.0	61.5	62.5
HE7	0.0	4.3	4.3	10.3	90.2	100.5	12.0	86.7	98.6
HE8	5.5	71.5	77.0	20.2	119.6	139.8	16.2	92.0	108.1
HE9	19.7	109.2	128.9	18.0	83.1	101.0	13.6	63.9	77.5
HE10	15.3	69.7	85.0	15.0	69.0	84.0	10.5	47.1	57.6
HE11	10.1	54.8	64.8	12.2	56.0	68.2	9.1	46.2	55.3
HE12	4.7	33.3	38.0	10.4	61.7	72.1	9.4	54.1	63.5
HE13	5.1	44.8	49.9	13.4	73.2	86.6	13.7	79.4	93.0
HE14	9.9	57.1	67.0	17.2	91.5	108.7	17.9	101.1	119.1
HE15	13.1	80.0	93.0	22.7	102.6	125.3	22.5	112.7	135.2
HE16	13.5	78.8	92.4	24.9	114.1	138.9	24.6	127.5	152.2
HE17	3.1	65.6	68.8	20.1	110.3	130.3	22.1	108.7	130.7
HE18	0.0	92.9	92.9	8.5	87.3	95.7	13.5	68.2	81.7
HE19	0.0	1.5	1.5	0.2	77.3	77.5	1.7	49.1	50.8
HE20	0.0	0.0	0.0	0.0	5.4	5.4	0.0	46.5	46.5
HE21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 6: Solar Allocation of Regulating Reserve for Base + 1000 = 3,366 MW solar

	Winter			Shoulder			Summer		
MST	Fast-moving	Following	Regulating	Fast-moving	Following	Regulating	Fast-moving	Following	Regulating
HE1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE5	0.0	0.0	0.0	0.0	1.0	1.0	0.0	1.1	1.1
HE6	0.0	0.0	0.0	1.4	37.6	39.0	0.8	74.2	75.0
HE7	0.0	4.0	4.0	10.9	106.0	117.0	13.2	107.9	121.0
HE8	5.6	82.1	87.7	22.2	141.6	163.8	18.1	114.9	133.0
HE9	22.3	115.5	137.8	20.3	106.7	126.9	16.3	79.4	95.7
HE10	18.2	96.5	114.7	17.9	88.1	105.9	12.7	63.6	76.2
HE11	12.0	75.0	87.0	14.4	76.7	91.1	11.7	57.7	69.5
HE12	5.5	47.8	53.3	14.2	93.3	107.5	11.9	76.2	88.1
HE13	6.7	61.5	68.2	16.5	100.2	116.7	15.6	99.9	115.5
HE14	10.9	73.0	83.9	22.3	127.1	149.4	21.8	129.5	151.2
HE15	17.2	102.4	119.5	26.2	141.9	168.0	28.6	132.8	161.3
HE16	17.0	101.5	118.5	29.3	154.1	183.4	30.5	162.0	192.5
HE17	4.6	83.3	87.9	26.2	145.4	171.6	26.4	140.9	167.3
HE18	0.0	125.2	125.2	11.5	114.3	125.8	16.5	92.2	108.7
HE19	0.0	2.0	2.0	0.3	103.7	103.9	2.0	68.4	70.4
HE20	0.0	0.0	0.0	0.0	15.1	15.1	0.0	72.7	72.7
HE21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 7: Solar Allocation of Regulating Reserve for Base + 1500 = 3,866 MW solar

	Winter			Shoulder			Summer		
MST	Fast-moving	Following	Regulating	Fast-moving	Following	Regulating	Fast-moving	Following	Regulating
HE1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE5	0.0	0.0	0.0	0.0	1.0	1.0	0.0	3.1	3.1
HE6	0.0	0.0	0.0	1.5	44.7	46.3	2.0	91.2	93.1
HE7	0.0	4.1	4.1	12.7	123.9	136.6	15.0	118.3	133.3
HE8	6.9	95.4	102.3	25.3	160.1	185.5	21.5	147.2	168.7
HE9	24.7	128.2	152.9	23.8	119.8	143.6	18.8	92.7	111.6
HE10	21.5	117.7	139.2	19.8	94.9	114.7	13.9	70.7	84.6
HE11	13.8	85.6	99.4	15.7	98.8	114.4	13.5	73.0	86.6
HE12	6.8	55.7	62.5	15.5	98.9	114.4	13.8	91.6	105.4
HE13	7.6	75.4	83.0	18.4	122.4	140.8	18.1	122.3	140.5
HE14	12.8	85.9	98.6	25.4	141.7	167.1	23.7	144.6	168.3
HE15	19.7	114.2	133.9	30.5	161.2	191.7	32.5	172.3	204.8
HE16	18.9	113.4	132.2	31.3	181.5	212.9	32.9	173.8	206.7
HE17	5.0	99.7	104.7	28.6	172.5	201.1	30.8	166.4	197.2
HE18	0.0	151.0	151.0	13.3	140.6	153.8	18.4	105.4	123.8
HE19	0.0	2.0	2.0	0.4	121.9	122.3	2.2	82.6	84.9
HE20	0.0	0.0	0.0	0.0	16.2	16.2	0.0	86.9	86.9
HE21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 8: Solar Allocation of Regulating Reserve for Base + 2000 = 4,366 MW solar

	Winter			Shoulder			Summer		
MST	Fast-moving	Following	Regulating	Fast-moving	Following	Regulating	Fast-moving	Following	Regulating
HE1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE5	0.0	0.0	0.0	0.0	1.0	1.0	0.0	4.2	4.2
HE6	0.0	0.0	0.0	1.5	53.1	54.6	2.0	107.6	109.6
HE7	0.0	6.0	6.0	13.9	144.5	158.4	16.3	130.1	146.3
HE8	7.4	111.2	118.6	25.3	186.8	212.2	22.7	150.7	173.4
HE9	26.7	159.0	185.7	24.7	129.1	153.8	19.4	99.7	119.1
HE10	22.8	126.2	148.9	21.7	102.1	123.8	14.6	78.6	93.2
HE11	14.4	84.8	99.2	16.3	100.8	117.1	14.1	75.6	89.7
HE12	6.8	61.1	67.8	15.5	101.3	116.8	15.0	94.8	109.8
HE13	8.9	82.4	91.3	19.1	134.7	153.8	18.7	140.6	159.3
HE14	14.0	93.5	107.5	26.2	154.7	180.9	25.4	147.1	172.5
HE15	20.3	134.3	154.6	32.9	166.8	199.7	33.3	171.2	204.5
HE16	20.3	130.7	151.0	33.7	193.4	227.0	35.2	179.4	214.6
HE17	5.0	118.5	123.5	29.7	196.1	225.9	31.1	177.2	208.4
HE18	0.0	171.2	171.2	13.8	157.7	171.5	20.3	115.4	135.7
HE19	0.0	2.0	2.0	0.4	144.3	144.7	2.2	99.0	101.2
HE20	0.0	0.0	0.0	0.0	15.0	15.0	0.0	108.5	108.5
HE21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HE24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Figure 9: Solar Allocation of Winter Regulating Reserve

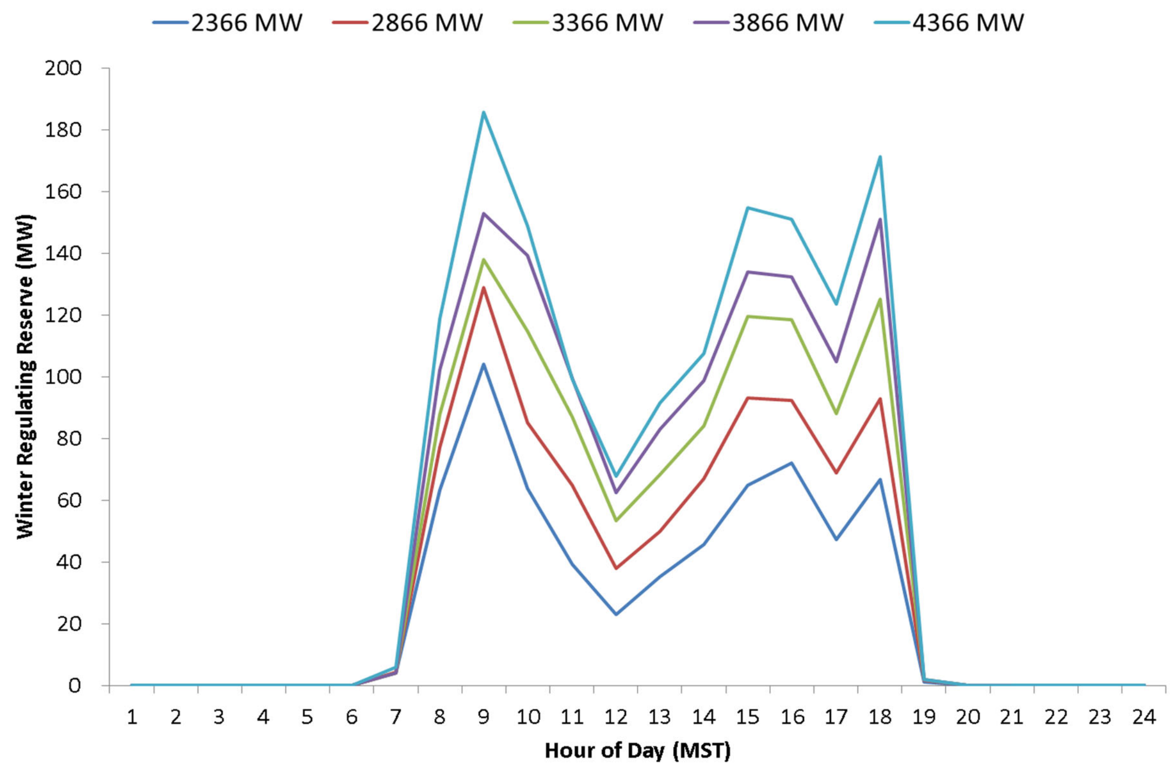
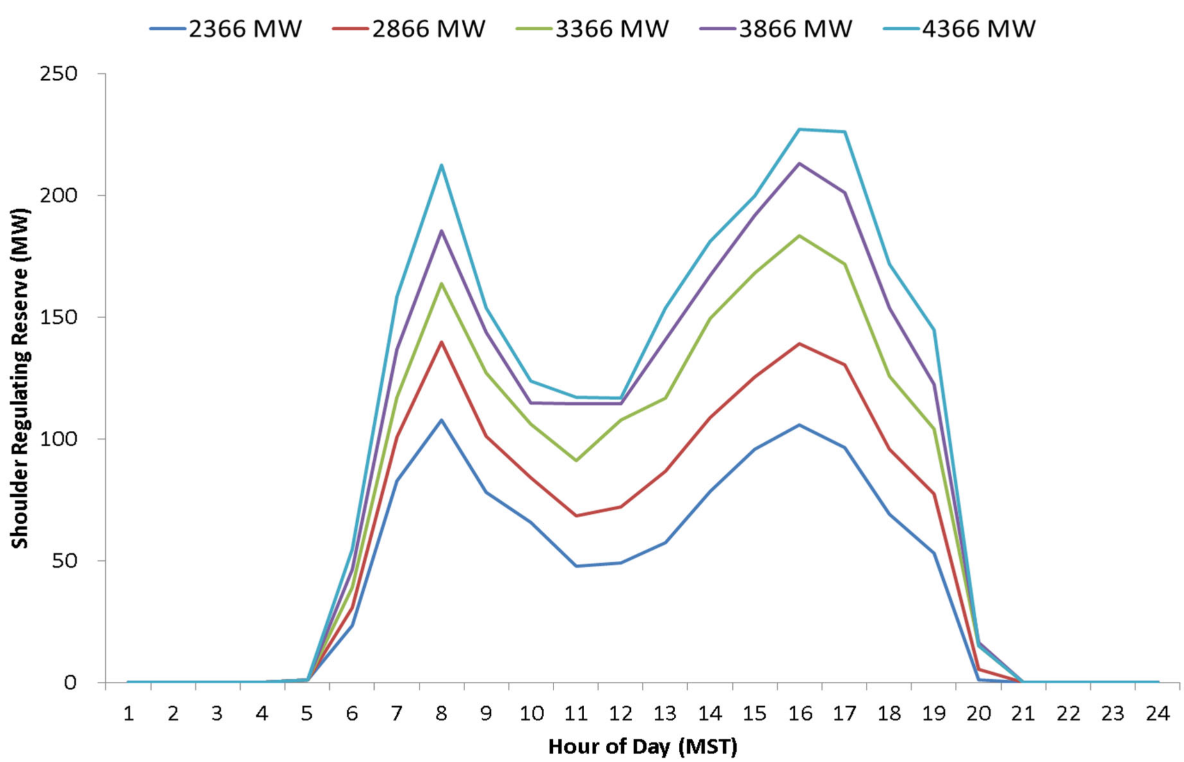
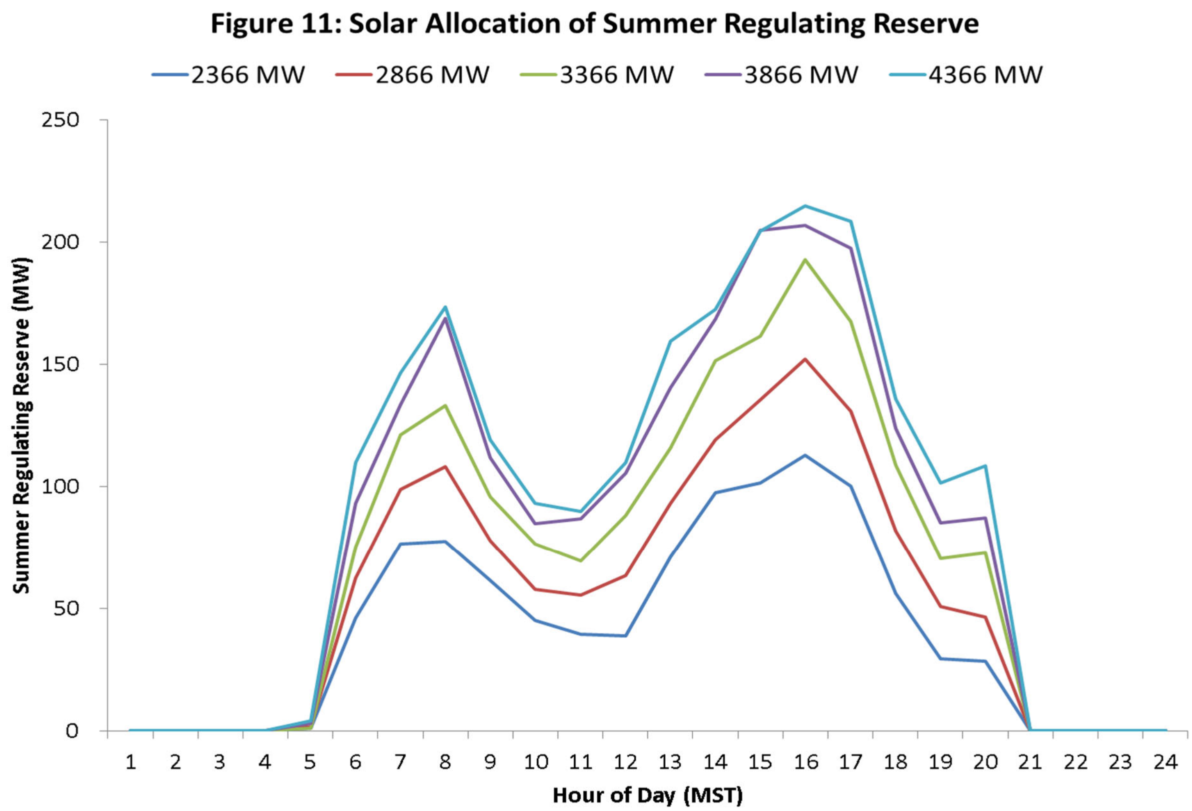


Figure 10: Solar Allocation of Shoulder Regulating Reserve





The Base Portfolio for solar generation represents the volume of solar generation already committed to by the Company and others within the BAA and includes over 2.3 GW of solar generation. Note that an increase of 2 GW of solar generation increases the maximum hourly Regulating Reserve volume by 82 MW in the Winter season, 119 MW in the Shoulder season, and 102 MW in the Summer season.

Next Steps

This study has determined the incremental volumes of reserve necessary to reliably integrate up to 1.5 GW of new wind generation and up to 2 GW of new solar generation within the BAA beyond levels already committed to by the Company and others. These incremental reserve requirements will be used as an input to production cost models used during Phase 2 of the Company's Electric Resource Planning Process. In Phase 2, the Company will evaluate various portfolios of generators to determine a preferred portfolio which meets the 80% carbon reduction by 2030 mandate while maintaining sufficient reserves to address the uncertainty of the portfolio of renewable generation and while keeping costs low for our customers.

Supplement to the 2020 Study of the Levels of Flex Reserve and Regulating Reserve Necessary for Reliable System Operation

October 2020

The TRC-approved Flex Reserve study completed in May 2020, studied the Flex Reserve requirements associated with adding up to 1500 MW of wind generation above the already existing wind generation within the PSCo BA as of ~2022; a total amount of installed wind of 6,462 MW. Based on the Company's near and long-term carbon reduction goals, the Company decided to study the Flex Reserve requirements associated with up to 3000 MW of incremental wind generation; a total amount of installed wind of 7,962 MW. This Supplement to the Flex Reserve Study applied the previously approved TRC methodologies to study the Flex Reserve requirements associated with up to 1500 MW of wind generation incremental to what was included in the Flex Reserve Study. The same 1-minute wind data from November 2015 through May 2019 was also used in the Supplemental Study.

In the Flex Study, we looked at various permutations of adding 500 MW of additional wind in each of ERZ1, ERZ2, and ERZ3. For this supplemental study, the Company boosted the volumes of incremental wind generation in each location to achieve the total volumes that we wanted to study. Table 1 lists the 1-minute wind generation profiles with time offsets that each represents an incremental 250 MW wind plant.

Table 1: Wind Generation Profiles for Incremental Wind Plants

Profile Capacity (MW)	ERZ1	ERZ2	ERZ3
500 (Flex Study)	CC2 +15 minutes CC2 +30 minutes	CDPT +15 minutes GW +30 minutes	TWBT +15 minutes TWBT +30 minutes
1000 (Supplemental Flex Study)	CC2 +15 minutes CC2 +30 minutes CC2 –15 minutes CC2 –30 minutes	CDPT +15 minutes GW +30 minutes CDPT –15 minutes GW +15 minutes	TWBT +15 minutes TWBT +30 minutes TWBT -15 minutes TWBT -30 minutes
1500 (Supplemental Flex Study)	CC2 +15 minutes CC2 +30 minutes CC2 –15 minutes CC2 –30 minutes CC2 +45 minutes CC2 +60 minutes	CDPT +15 minutes GW +30 minutes CDPT –15 minutes GW +15 minutes GW + 45 minutes GW + 60 minutes	TWBT +15 minutes TWBT +30 minutes TWBT -15 minutes TWBT -30 minutes TWBT –45 minutes TWBT +45 minutes

The Company then constructed wind generation portfolios with various permutations of incremental wind generation in each of the ERZs. The final Flex Reserve Requirement for a particular volume of wind generation (e.g. Base Case + 2000 MW = 6,962 MW) was the average of the Flex Reserve Requirements for the underlying portfolios (e.g. Profiles A through F). Table 2 lists the six profiles (A-F) with a total wind portfolio capacity of 6,962 MW and the contribution of incremental wind generation from each ERZ. Table 3 lists the six profiles (A-F) with a total wind portfolio capacity of 7,462 MW and Table 4 lists the seven profiles (A-G) with a total wind portfolio capacity of 7,962 MW, along with the contributions of incremental wind generation from each ERZ.

Table 2

Base Case + 2000 MW = 6,962 MW			
Profile	ERZ1	ERZ2	ERZ3
A	1000	500	500
B	500	1000	500
C	500	500	1000
D	1000	1000	0
E	1000	0	1000
F	0	1000	1000

Table 3

Base Case + 2500 MW = 7,462 MW			
Profile	ERZ1	ERZ2	ERZ3
A	1000	1000	500
B	1000	500	1000
C	500	1000	1000
D	500	500	1500
E	500	1500	500
F	1500	500	500

Table 4

Base Case + 3000 MW = 7,962 MW			
Profile	ERZ1	ERZ2	ERZ3
A	1000	1000	1000
B	1500	500	1000
C	1500	1000	500
D	1000	500	1500
E	1000	1500	500
F	500	1000	1500
G	500	1500	1000

Figure 1 shows the 30-minute Flex Reserve Requirement for the three wind generation portfolios studied in the Supplemental Study (6,962 MW, 7,462 MW, and 7,962 MW). In Figure 1, wind generation is measured along the horizontal axis and the required Flex Reserve is measured along the vertical axis.

Figure 1: 30-minute Flex Requirement for Supplemental Study wind portfolios

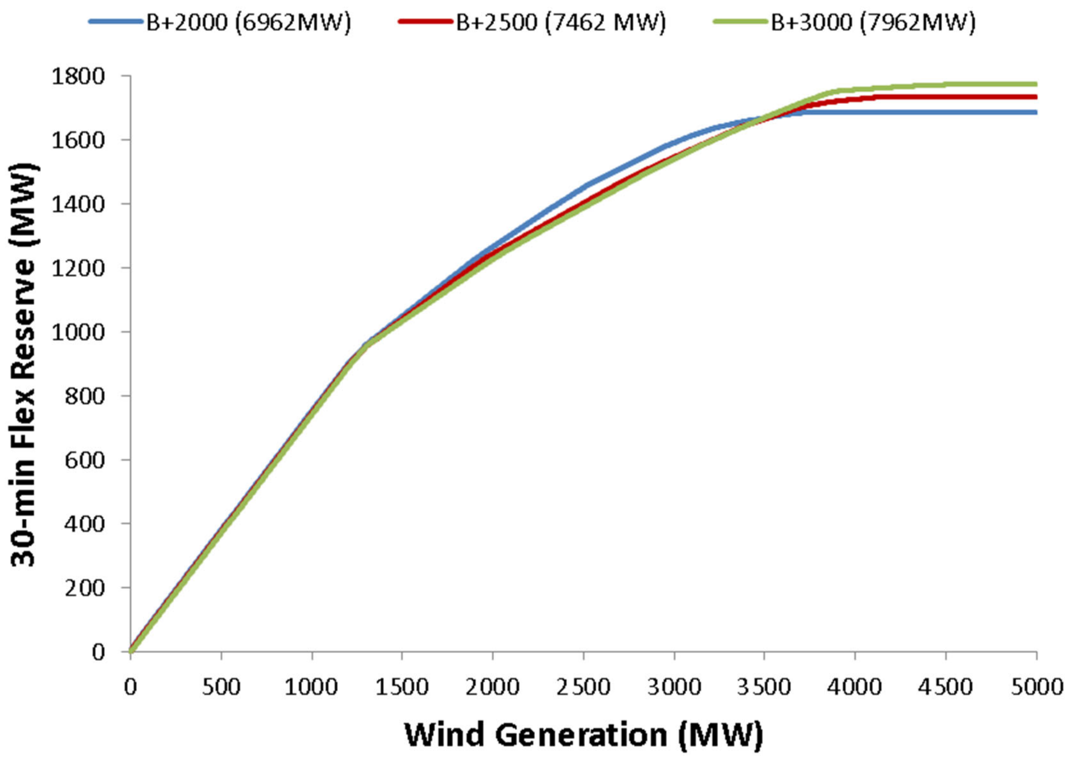


Figure 2 compares the Base Case + 1500 MW portfolio from the Flex Reserve Study and the Base Case + 2000 MW portfolio from the Supplemental Study. Note that the resulting Flex Reserve Requirement is almost identical for these two portfolios. Rather than applying separate Flex Reserve Requirements for these portfolios, the Company recommends using the Base Case + 1500 MW Flex Reserve Requirement for both portfolios.

Figure 3 compares the Flex Reserve requirements from the various portfolios in the Flex Reserve Study and the Supplemental Study. Note that the Base Case + 2000 MW curve is not displayed as it is almost identical to the Base Case = 1500 MW curve. Table 5 lists the maximum Flex Reserve Requirement for each of the wind portfolios.

Table 5: Maximum 30-minute Flex Requirement for wind portfolios

Wind Portfolio	Wind Generation Capacity	Maximum Flex Reserve
Base Case	4,962 MW	1,390.7 MW
Base Case + 500 MW	5,462 MW	1,493.6 MW
Base Case + 1000 MW	5,962 MW	1,552.8 MW
Base + 1500 MW, Base + 2000 MW	6,462 MW and 6,962 MW	1,691.1 MW
Base Case + 2500 MW	7,462 MW	1,733.4 MW
Base Case + 3000 MW	7,962 MW	1,773.3 MW

Figure 2: Flex Reserve for Base Case + 1500 MW and Base Case + 2000 MW

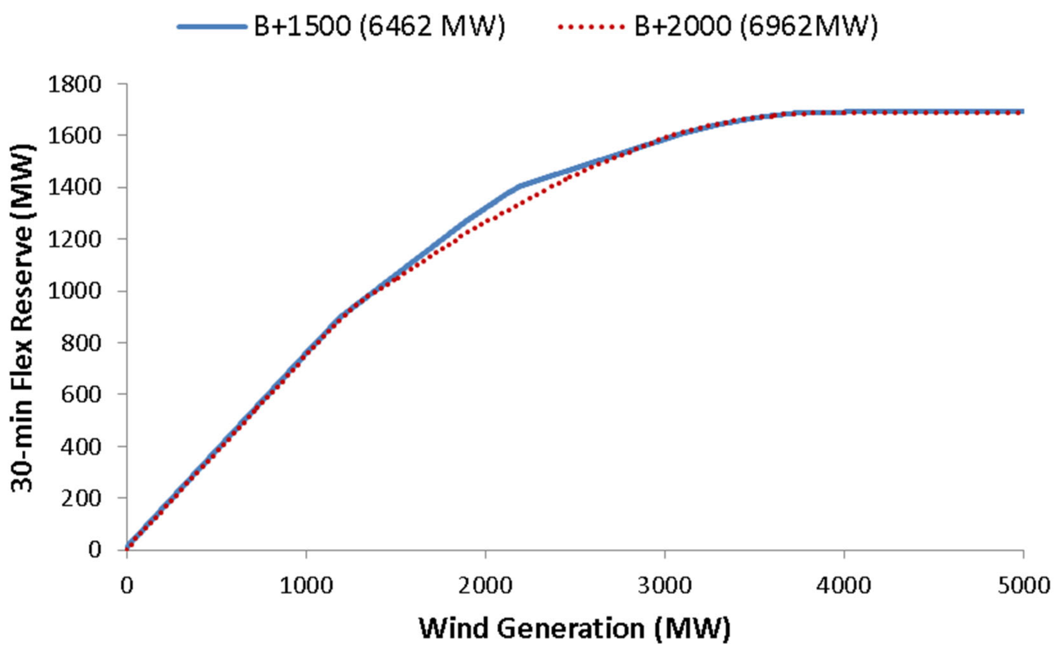
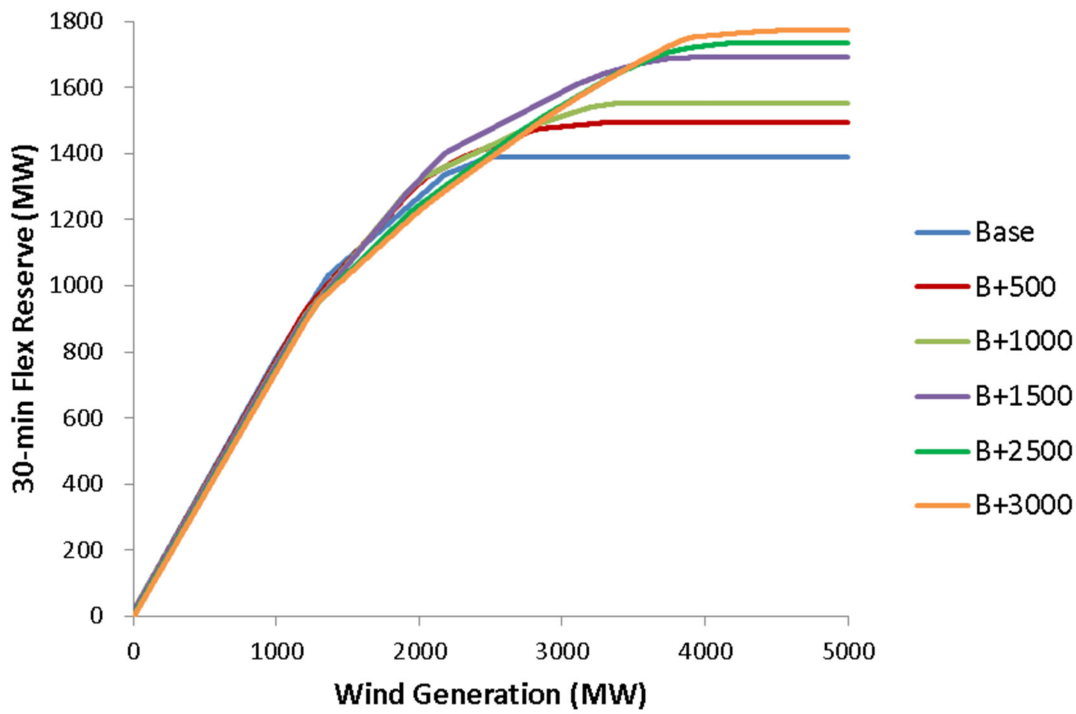


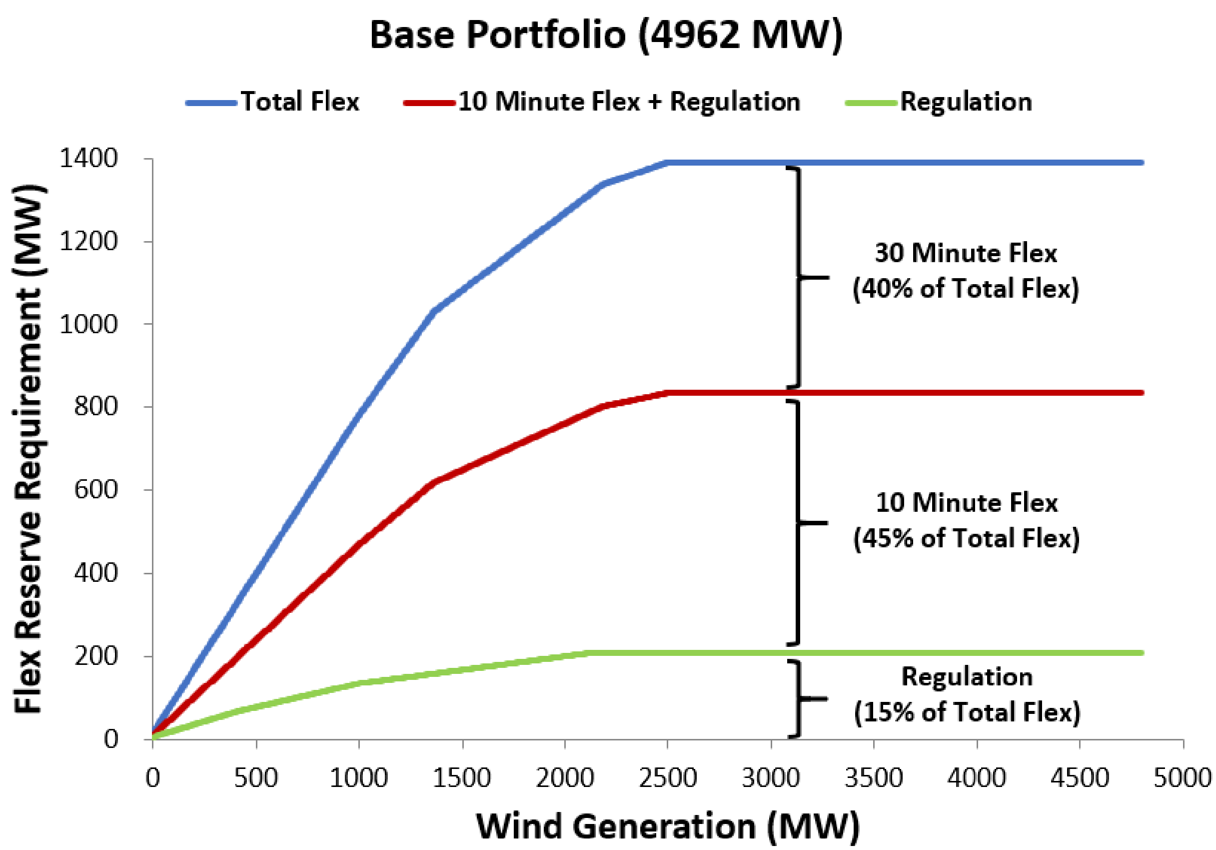
Figure 3: Flex Reserve curves from Flex Study and Supplemental Study



Regulation portion of 10-minute Flex Reserve

There are several components that make up the total Flex Reserve requirement. The total Flex Reserve is based on the maximum 30-minute loss of wind generation for a given starting volume of wind generation. Of this total Flex Reserve volume, 60% must be comprised of resources available within 10 minutes. In the Flex Reserve Study, Regulating Reserve only accounts for the Fast-Moving and Following components attributable to Load and Solar generation. Any regulation attributable to wind is assumed to be covered by Flex Reserve. To account for the Regulating Reserve attributable to wind generation, the Company calculated the 95th percentile of 10-minute wind generation down ramps for each 100MW generation bin for each wind generation portfolio. The maximum 10-minute Regulating Reserve value was consistently ~15% of the Maximum Flex Reserve requirement or ~25% of the 10-minute component of Flex Reserve.

Figure 4 shows the various components of the 30-minute Flex Reserve Requirement for the Base Case Portfolio. The first 15% of the Flex Reserve Requirement must be comprised 10-minute online resources. The next 45% of the Flex Reserve Requirement can be served with 10-minute resources either online or offline. The last 40% of the Flex Reserve Requirement can be served with any resource available within 30 minutes.



2021 Wind and Solar Integration Cost Study on the Public Service of Colorado System

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March 31, 2021

Executive Summary

Wind and solar integration costs on the Public Service of Colorado (PSCo) system grow with increased penetration of renewable generation. The integration costs for solar energy grow at a rate of $0.72/MWh while wind energy increases at a rate of $2.84/MWh. Further, these costs change with natural gas price at a rate of $0.30/MWh and $0.50/MWh for every $1/MMBtu change in natural gas price. These costs reflect the growing forecast uncertainty in wind and solar generation enacted on a 2030 representation of the PSCo system. Combined, the integration costs can be escalated to reflect the natural gas price in any year of study.

Table 1 – Integration Costs and Rate of Change of Integration Costs

	Integration Cost ($/MWh)	Rate of Change ($/MWh per $/MMBtu)
Wind Generation	$2.84	$0.50
Solar Generation	$0.72	$0.30

This report details the above findings for 4 GW to 8 GW of total wind capacity and 2 GW to 5 GW of total solar capacity. The study methodology is the same as adopted for the 2016 solar integration cost study,[1] which in turn, is like methodologies adopted in integration cost studies prior. For example, the same method for deriving the solar and load forecast/actual pair data was utilized. Additionally, the non-wind and solar portfolio was based on a future (i.e., 2030) system rather than the present resource mix. Though, there are notable deviations from prior studies. The wind forecast/actual pair data was derived from operational data from a recent test year, rather than derived from NREL's Western Wind Resources Dataset. The solar integration costs were calculated with 5 GW of total wind capacity on the system and the wind integration costs were calculated with 3 GW of total solar capacity. The cases are shown in Table 2 below.

Three natural gas sensitivities were studied. The low, base, and high cases (Table 2) reflect the three natural gas forecasts adopted in the 2021 Energy Resource Plan in year 2030. The results from the base case provides the final integration costs as reported in Table 1, with the low, base, and high cases used to derive the rate of change of the integration costs.

The wind and solar integration costs are consistent with integration costs calculated in past studies. A constant rate was adopted across both the wind and solar penetration levels because it was both appropriate and simple.

[1] Xcel Energy Service Inc. "An Integrated Cost Study for Solar Generation Resources on the Public Service Company of Colorado System,", May 27, 2016.

Table 2 – Wind and Solar Integration Cost Run Matrix

Wind Integration Study *natural gas sensitivities $/MMBtu*

Case	Wind	Solar	Low	Base	High
1	4GW	3GW	$ 2.89	$ 3.46	$ 4.12
2	5GW				
3	6GW				
4	7GW				
5	8GW				

Solar Integration Study *natural gas sensitivities $/MMBtu*

Case	Wind	Solar	Low	Base	High
1	5GW	2GW	$ 2.89	$ 3.46	$ 4.12
2		3GW			
3		4GW			
4		5GW			

Introduction

Prior renewable integration cost studies have evaluated three components of integration costs: 1) impacts on electric system regulation, 2) impacts on electric system operation given uncertainty in wind and solar forecast generation versus actual generation, and 3) impacts on the Company's gas supply/storage system. Integration costs are narrowly defined herein as those costs derived from the inherent uncertainty of the wind and solar resources – previously called the System Operations Component of integration costs. Though, other integration costs relating to reserve requirements, gas system flexibility and supply, and firm capacity requirements are holistically being included in the Energy Resource Plan (ERP) modeling framework. As the ERP process has matured to endogenously consider numerous implications of a high renewable energy future such as increasing regulation reserves and firm fuel needs, costs due to uncertainty remain outside the modeling framework and are the primary focus of this study. As such, integration cost and uncertainty cost are used interchangeably.

Uncertainty costs derive from irreversible decisions due to imperfect information. In the power system, commitments are made in advance of real-time so as to ensure both reliable capacity and least-cost energy. These decisions require foresight. When information changes about the future, such as demand and renewable energy forecasts or unit availability, decisions to commit units may be irreversible, or the decision to forego commitment of less expensive facilities are now replaced with fewer, more expensive options. Often, even in the face of new information, the decisions made in the past are maintained, because the updated information is also uncertain (though a little less so) – and attempt to reverse a decision already made may leave one in an even greater bind in the future. Only at real-time are the costs of uncertainty realized; a culmination of prior decisions and indecisions, made in earnest, now are determined to be suboptimal relative to a modeled, perfect foresight, result. Uncertainty costs are added to resources that cause uncertainty. This appropriately costs this real-world burden that is otherwise ignored in the modeling framework.

The report details study methodology next, followed by results and conclusions.

Study Methodology

The study adopts the same methodology as the 2016 Solar Integration Cost study with some notable exceptions. The Company employed PLEXOS®, a production cost model licensed from Energy Exemplar, with a 2030 representation of the PSCo system. A day-ahead commitment of resources and power purchases and sales are made based on demand and renewable energy forecasts. These commitments are carried forward to real-time where actual demand and renewable energy production are balanced with a redispatch of on-line resources and purchase of real-time power. Additional units may be brought on-line to cover shortages, though possibly at great expense.

Case Development: Isolating Wind and Solar Integration Costs

Cases were developed with and without uncertainty for one resource type (wind or solar) layered on top of a base level of load and wind or solar uncertainty. For example, the wind integration study considered incremental uncertainty layered on top of load uncertainty and 3 GW of solar uncertainty, while the solar integration study considered incremental uncertain layered on top of load uncertainty and 5 GW of wind uncertainty (Table 3). This method was developed to isolate the impact of wind and solar over a reasonable base of uncertainty coming from other resources or loads.

Table 3 – Wind and Solar Integration Cost Run Matrix

Wind Integration Study — *natural gas sensitivities $/MMBtu*

Case	Wind	Solar	Low	Base	High
1	4GW	3GW	$ 2.89	$ 3.46	$ 4.12
2	5GW				
3	6GW				
4	7GW				
5	8GW				

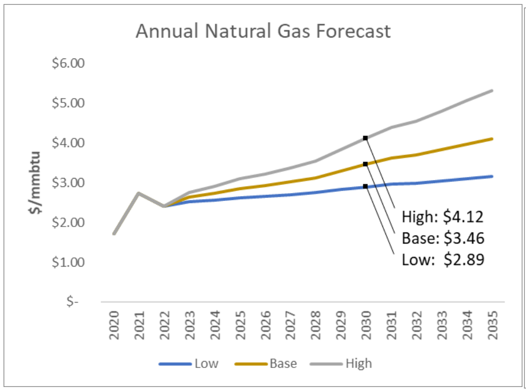
Solar Integration Study — *natural gas sensitivities $/MMBtu*

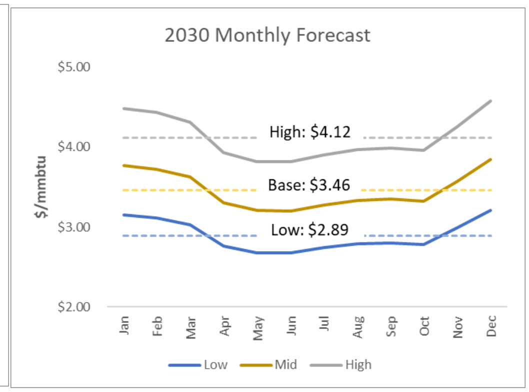
Case	Wind	Solar	Low	Base	High
1	5GW	2GW	$ 2.89	$ 3.46	$ 4.12
2		3GW			
3		4GW			
4		5GW			

Natural Gas Sensitivities

Three natural gas sensitivities were studied. The low, base, and high sensitivities (Table 3) reflect the three natural gas forecasts adopted in the 2021 Energy Resource Plan in year 2030. Figure 1 shows the ERP natural gas forecast with the 2030 low ($2.89/MMBtu), base ($3.46/MMBtu), and high ($4.12/MMBtu) values highlighted. In the second chart, the 2030 monthly values are shown; the simple average equaling the annual forecast. These forecast values were adopted for this study. The base case sensitivity provided the final integration cost value while the low, base, and high sensitivities were used to derive the rate of change of integration cost relative to natural gas prices.

Figure 1 – ERP Natural Gas Forecast and the 2030 Monthly Forecast





Forecast/Actual Pair Development

Modeling uncertainty requires the development of forecast data paired with realized, or actual, data. These datasets are referred as forecast/actual pair data. Forecast/actual pair data were developed for load, wind energy, and solar energy.

Load Data

Realized 2030 hourly load data was developed using the PLEXOS® model based on 2030 peak and energy forecasts and historic load shapes. Hourly forecast load errors for 2030 were assumed to be identical to actual hourly forecast load errors from 2011. That is, the required 2030 day-ahead hourly load value were calculated by combining the 2030 hourly load data and the 2011 actual hourly forecast load errors. 2011 data were used as they have low levels of net-metered solar generation embedded in the hourly load values than data from later years.

Wind Data

Forecast/actual pair data for wind energy are based on actual PSCo operations. The forecast/actual pair data are based on a historic test year from August 2019 to July 2020. The level of wind was constant over this period at 3125 MW of installed capacity. These forecast/actual pair data are scaled linearly to derive ever higher level of wind generation. There is an inherent trade-off in accepting and scaling known, real data in lieu of speculating on the future state and location of wind turbines. On one hand, actual data is superior to any synthesized data. On the other, limiting oneself to existing data eliminates consideration of future locations and turbine types. This study firmly sides with known, real data as a better basis for future uncertainty than to speculate on the turbine type, geographic extent, and weather at a new, undeveloped location that assume synthesized forecast/actual pair data in the process.

Solar Data

Conversely, there is not enough data to do the same for solar energy. Solar energy forecast/actual pairs are derived using NREL's Solar Power Data for Integration Studies[2] data; the same source as used in the

[2] Solar Power Data for Integration Studies - https://www.nrel.gov/grid/solar-power data.html

2016 solar integration study. Like in 2016, an exhaustive reconciliation of existing and future locations of solar was undertaken. The Solar Power Data includes geographic-specific forecast/actual data pairs for distributed (DPV) and utility-scale (UPV) solar generation in Colorado.

Distributed Solar Generation

Each of the ~60,000 existing distributed generators totaling 604 MW of installed capacity was mapped to the nearest distributed solar generation profile resulting in 30 DPV generation profiles. Distributed generation was assumed to grow proportionally according to the 2020 geographic share. Distributed generation is capped at 1500MW in the high penetration cases assuming growth in distributed generation can be accelerated to some extent but cannot grow at the accelerated pace needed to meet the higher penetrations studied. Table 4 shows the share of distributed solar generation by region in each of the future cases.

Table 4 – Distributed Solar Generation Share of Future Cases

	2020	Future Cases (based 2030)			
Case	n/a	2GW	3GW	4GW	5GW
DPV Share	*604*	*1000*	*1200*	*1500*	*1500*
NFR	547	905	1086	1357	1357
SFR	18	29	35	44	44
SE	0	0	0	0	0
SLV	0	0	0	0	0
WS	40	66	79	99	99
Other	0	0	0	0	0

*NFR – Northern Front Range, SFR – Southern Front Range, SE – Southeast, SLV – San Luis Valley, WS – Western Slope

Utility-Scale Solar Generation

Existing and planned utility-scale solar generators totaling 1124 MW were mapped to the nearest utility-scale solar generation profile resulting in 8 UPV generation profiles. The first tranche of utility-scale solar was assumed to be proportional to the existing and planned utility-scale solar generation installations. Thereafter, growth was assumed to be equal across five regions of Colorado. Table 5 shows the share of utility-scale solar generation in each of the future cases.

Table 5 – Utility-Scale Solar Generation Share of Future Cases

	2020	Future Cases (based 2030)			
Case	n/a	2GW	3GW	4GW	5GW
UPV Share	*1124*	*1000*	*1800*	*2500*	*3500*
NFR	122	109	257	397	597
SFR	670	596	805	945	1145
SE	200	178	335	475	675
SLV	132	117	267	407	607
WS	0	0	135	275	475
Other	0	0	0	0	0

*NFR – Northern Front Range, SFR – Southern Front Range, SE – Southeast, SLV – San Luis Valley, WS – Western Slope

Non-Wind and Solar Generation Portfolio

The non-wind and solar generation portfolio is assumed to be largely gas-fired generation with some battery and pumped hydro storage. Coal-fired plants are either retired (Hayden, Craig, Comanche 1, Comanche 2) or converted to natural gas (Pawnee, Comanche 3)[3]. The 2030 portfolio includes solar plus storage facilities, refurbishment of Cabin Creek, continued access to bilateral markets, and enough natural gas-fired combustion turbine capacity to replace expiring contracted or owned facilities.

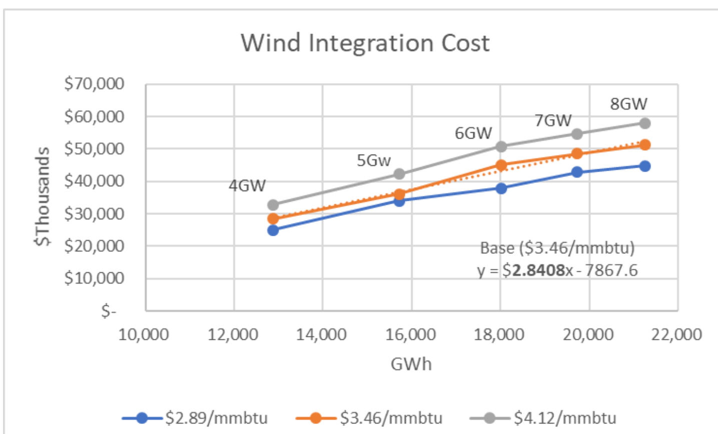
Study Results and Conclusions

Wind and solar integration costs are presented with the change in integration costs as a function of natural gas price.

Wind Integration Cost

Total wind integration costs for cases 4 GW to 8 GW, and three natural gas sensitivities, are shown in Figure 2. The existing wind integration cost is the rate at the 4 GW level (base case), or \$2.21/MWh.[4] The incremental costs from 4 GW to 8 GW are consistently linearly with generation. The regression of the base case is shown with an incremental cost of \$2.84/MWh. The difference between the high and low sensitivities relative to the base sensitivity results in an average cost differential of \$0.49/MWh (high) and \$0.51/MWh (low) for every \$1/MMBtu difference in natural gas price. The average of these two differentials as taken as the final result of \$0.50/MWh change in integration cost for every \$1/MMBtu change in natural gas price.

Figure 2 – Wind Integration Costs



Solar Integration Cost Results

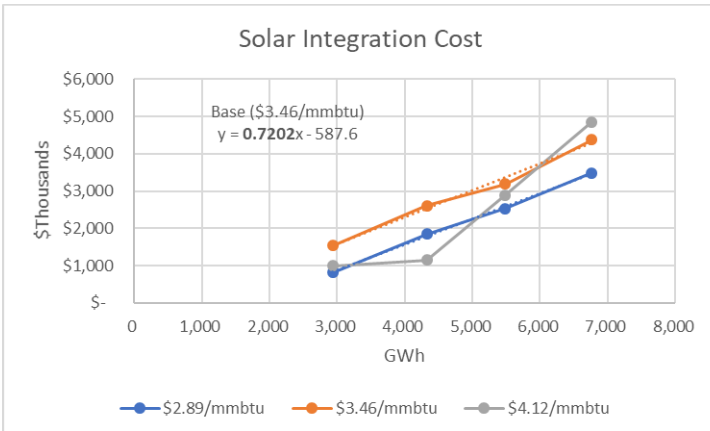
Total solar integration costs for cases 2 GW to 5 GW, and three natural gas sensitivities, are shown in Figure 3. The base and low sensitivity costs are consistently linearly with generation. The high sensitivity does not show a consistent nor intuitive result. The author suspects inconsistencies in the PLEXOS® model

[3] Whether an existing coal-fired unit is modeled as a gas-fired unit or remains a coal-fired unit is not expected to affect the magnitude of the resulting integration costs as a single unit represents a small portion of the overall generation portfolio.

[4] This is the slope of the line between 0 GW and 4 GW wind with a gas cost of \$3.46/MMBtu.

results for the high sensitivity studies. As such, the high sensitivity case is thrown out – as there is enough data between the low and base simulations to derive a consistent result. The existing solar integration cost is the rate at the 2 GW level (base case), or $0.52/MWh.[5] The regression of the base case is shown with an incremental cost of $0.72/MWh. The difference between the low sensitivity relative to the base sensitivity results in an average cost differential of $0.30/MWh for every $1/MMBtu difference in natural gas price.

Figure 3 – Solar Integration Costs



The result of the wind and solar integration cost study are shown in Table 6. Wind and solar energy have different integration costs. Wind energy has higher uncertainty costs and are more influenced by natural gas prices. Solar energy has much lower uncertainty costs – which is consistent with prior results.

Table 6 – Integration Costs and Rate of Change of Integration Costs ($2030)

	Integration Cost ($/MWh)	Rate of Change ($/MWh per $/MMBtu)
Wind Generation	$2.84	$0.50
Solar Generation	$0.72	$0.30

[5] This is the slope of the line between 0 GW and 2 GW solar with a gas cost of $3.46/MMBtu.

2021 Effective Load Carrying Capability Study of Existing and Incremental Renewable Generation and Storage Resources

on the

Public Service Company of Colorado System

in support of its

2021 Electric Resource Plan Filing

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Executive Summary

This report presents the results of a recent Effective Load Carrying Capability ("ELCC") study conducted on existing hydro, solar, wind, and storage resources and incremental solar, wind, and storage resources on the Public Service Company of Colorado (the "Company") system. Prior to this, the most recent solar and wind ELCC studies for the Company were conducted in 2016 and 2017.

The current study determines ELCC values for existing and incremental solar and wind generation and storage resources; it does so on both standalone (i.e., the resource ELCC calculated in isolation) and on total portfolio bases. For purposes of this study, existing is defined as the hydro, solar, wind, and storage resources currently operational plus those stand-alone solar and solar hybrid facilities contracted to be operational at the start of year 2023[1]. Incremental wind generation was evaluated within four Energy Resource Zones in Colorado; incremental solar generation was evaluated within six solar resource zones; incremental storage generation was evaluated on both a standalone basis and as part of hybrid solar with storage facilities. Storage resource ELCCs were calculated using a methodology that allocates storage's limited energy to the highest loss of load probability hours in the Company's net load profile.

ELCC results for portfolios do not typically equal the sum of the standalone ELCC results. The portfolio ELCC values depend upon: 1) the amount and locations of resources already in the Company's existing portfolio, 2) the total MW of incremental resources, and 3) the relative proportions and locations of the various resource types assumed in combination. Standalone ELCCs can serve as proxies in the creation of cost effect portfolios of incremental generation resources, but a separate calculation of portfolio ELCC is required in the selection of cost-effective, reliable resource portfolios.

Study results illustrate the benefits of geographic and generation technology diversity in maximizing ELCC benefits of a portfolio of resources. The study results also clearly demonstrate the declines in ELCC that occur with incremental penetrations of non-dispatchable renewable generation (e.g., solar and wind) found in prior studies and documents the decline in ELCC for energy-limited resources (e.g., storage) noted in other studies. Study results show that the co-location of solar and wind and the co-location of solar and storage should not result in significantly large reductions in ELCC as compared to similar levels of resources that are not co-located.

[1] There are no additional wind or hydro resources contracted to be operational before 2023.

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Introduction

Background

In order to reliably serve its customers' electricity demands, Public Service Company of Colorado ("Public Service" or the "Company") forecasts expected, peak loads for its system as well as the ability of its existing and planned generation resources to reliably serve those forecast loads. For resource planning purposes, different generation technologies provide different levels of their nameplate generation capacity rating toward reliably serving customer load. In general, the Company affords 100% of a dispatchable, fossil fuel-fired generator's net dependable capacity for resource planning purposes, but less than 100% of nameplate capacity for non-dispatchable, intermittent generation technologies (e.g., wind and solar) and for energy-limited resources (e.g., storage). Underestimating the contribution of intermittent generation and energy-limited resources to help meet forecast system peaks can result in the acquisition of additional generation capacity and higher system costs. Overestimating the ability of such resources to help serve forecast system peaks can result in lower levels of system reliability and increased risks of customer load curtailment.

A facility's capacity credit (or capacity value) is frequently confused with the facility's capacity factor. A facility's capacity credit is a probabilistic measure of the fraction of the facility's nameplate rating (measured in MW) [2] that can be relied on to serve customer loads. A facility's capacity factor is the ratio of the total amount of energy (measured in MWh) that the facility is expected to generate over a specific time period to the maximum amount of energy it could generate if it were operated during the time period at full nameplate capacity; capacity factors are typically provided on an annual basis and presented as "net capacity factor" or "NCF".

For its resource planning purposes the Company utilizes an effective load carrying capability ("ELCC") method to determine the capacity credit for non-dispatchable renewable and dispatchable storage resources. ELCC study results are dependent upon the selection of a specific reliability target. In this study, the Company utilized a loss of load expectation ("LOLE") reliability target of 1 event (1 hour) in 10 years which is consistent with the reliability target utilized in the Company's most recent planning reserve margin study.

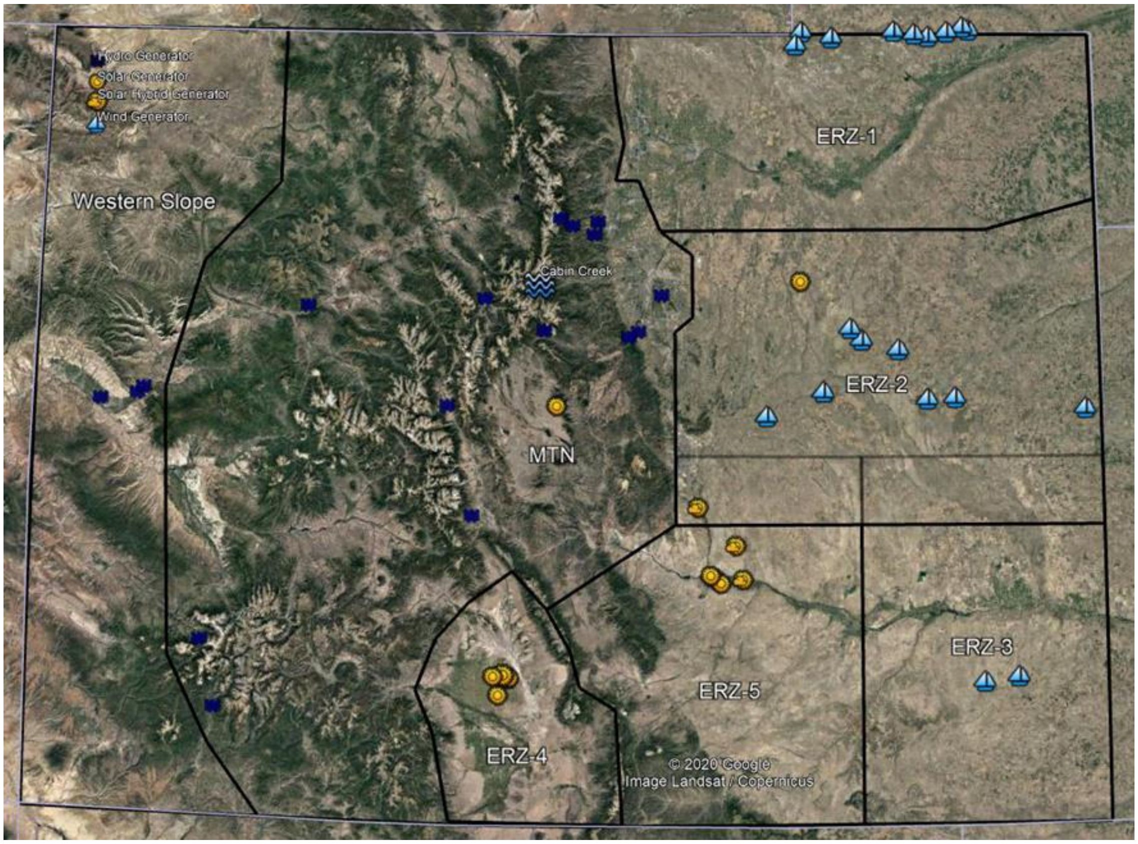
Prior ELCC Studies

Company's most recent ELCC study on Cabin Creek was conducted in 1999 and assigned 210 MW of capacity credit to the facility. The Company has not previously conducted an ELCC study on its hydro portfolio. See Figure 1 for approximate locations of the utility resources and their

[2] Unless otherwise indicated, the terms "MW" and "MWh" in this study report refer specifically to MW_{AC} and MWh_{AC}.

location within the designated Energy Resource Zones ("ERZs") in southern and eastern Colorado and geographic solar resource zones across Colorado.[3]

Figure 1 Locations of Existing Hydro, Solar, Wind and Storage Resources



Solar

The Company conducted two solar ELCC studies in support of its 2016 ERP.[4] Those studies determined the ELCC attributable to the existing solar at the end of 2015 (161 MW calculated as 55% * 135 MW for utility solar + 37% * 235 MW for behind-the-meter solar) and to incremental

[3] Current solar resource zones include: Northern Front Range, Southern Front Range, Southeast, San Luis Valley, Mountain, and Western Slope. Northern Front Range ("NFR") is generally all of ERZ-1, the portions of ERZ-2 above 38°52", and the Denver/Boulder Metro area. Southern Front Range ("SFR") is all of ERZ-5 and the southwestern portion of ERZ-2 below 38°52". Southeast ("SE") is all of ERZ-3 and the southeastern portion of ERZ-2 below 38°52". San Luis Valley ("SLV") is all of ERZ-4. Western Slope ("WS") is the non-mountainous regions of the counties bordering Utah. Mountain ("MTN") is all other. Figure 1 does not illustrate the locations of existing behind-the-meter and community solar garden solar generators. Such generators are primarily sited in the Company's Denver/Boulder Metro area load center but can be found in all the solar resource zones except for the Southern Front Range and Southeast solar zones.

[4] These study reports were filed as Attachments KLS-2 and KLS-8 in Proceeding 16A-0396E.

tranches of fixed and one-axis tracking solar in four broad geographic zones. Average ELCC results applicable to incremental solar from the two studies are aggregated in Table 1 below.

Table 1 Average ELCC to Apply to Incremental Solar from Prior Study Results

Incremental Solar	**Northern Front Range**		**San Luis Valley**		**Southern Front Range**		**Western Slope**	
(MW)	Fixed	Tracking	Fixed	Tracking	Fixed	Tracking	Fixed	Tracking
100	37.0%	41.5%	43.5%	52.5%	46.0%	59.7%	41.5%	53.0%
250	35.8%	40.2%	42.2%	50.4%	44.1%	58.1%	41.0%	52.0%
500	33.9%	37.8%	39.1%	47.1%	41.4%	55.1%	39.0%	49.5%
1000	30.3%	33.2%			35.9%	48.3%		
1500	27.7%	29.1%						

The prior study documented the rapid decline in solar ELCC with increasing penetrations; for example, in the Northern Front Range the first 100 MW of Tracking solar would be assigned 41.5%, but the last 500 MW to get to 1500 MW total would be assigned 20.9%.[5] The study also documented the incremental ELCC value from installing PV modules in one-axis tracking configurations versus fixed ones; the average ratio of fixed/tracking solar ELCC in Table 1 is 83%.

Wind

The Company most recently conducted two wind ELCC studies in support of its 2016 ERP.[6] Those studies calculated the ELCC attributable to the existing wind at the end of 2015 (409 MW, calculated as 16% * 2,555 MW) and to incremental tranches of wind in four Energy Resource Zones. Average ELCC results applicable to incremental wind from the two studies are aggregated in Table 2 below.

The prior study documented the rapid fall off in ELCC with increasing penetrations in ERZs where the Company has relatively little or no existing generation resources; 18.8% ELCC for first 250 MW tranche and 11.0% for the last 500 MW tranche in ERZ-3 and 14.8% ELCC for the first 250 MW trance and 7.5% for the last 500 MW tranche in ERZ-5. In ERZ-1 and ERZ-2—where the Company had the bulk of its wind generation resources in 2015 (and continues to in 2021)—the overall ELCC values were relatively low and didn't decline at as high a rate with increasing penetrations as in those areas where the Company has little installed wind generation.

[5] Graphs of average and incremental ELCC for the data in Tables 1 and 2 are provided in the original study reports.
[6] These study reports were filed as Attachments KLS-4 and KLS-10 in Proceeding 16A-0396E.

Table 2 Average ELCC to Apply to Incremental Wind from Prior Study Results[7]

Incremental Wind (MW)	ERZ-1	ERZ-2	ERZ-3	ERZ-5
250	10.0%	9.8%	18.8%	14.8%
500	9.7%	9.2%	16.9%	12.8%
1000	9.1%	8.4%	14.0%	10.2%
1350		7.9%		
1850		7.4%		

Existing Levels of Hydro, Solar, Wind, and Storage Resources

The Company's most recent competitive acquisition for utility generation resources was in conjunction with its 2016 Electric Resource Plan ("ERP") filed May 31, 2016.[8] The competitive acquisition phase of that ERP evaluated resource acquisitions with in-service dates no later than May 1, 2023 to meet a 2023 summer resource need. All the wind generation resources acquired through the 2016 ERP are currently operational. However, none of the standalone solar or solar hybrid resources acquired through the 2016 ERP are operational; most of those resources have in-service dates no later than end of year 2022.

Given the large volume of solar expected between start of year 2021 and start of year 2023, the Company calculated ELCCs at the levels of renewables and storage that are expected to exist at each of these times. For purposes of setting a baseline of resources for the Company's next competitive solicitation, existing solar resources will include all solar resources expected to be in-service at the start of 2023 including those acquired through the 2016 ERP.

Estimates of the volume of behind-the-meter solar were based on assumed levels of incremental growth for the years 2020-2022. Locations of future behind-the-meter solar installations were assumed to occur in the same proportions as existing locations for those resources. Estimates of the volume and locations of community solar gardens were based on winning bids in recent competitive acquisitions and targeted acquisition rates (with locations in similar proportions to current and planned resources). See Table 3 for a summary of the hydro, solar, wind, and storage resources expected to exist at the start of 2023.

[7] Prior ELCC studies used different labels to describe the various ERZs in Colorado. ERZ-1 = Northern, ERZ-2 = Limon, ERZ-3 = Lamar.

[8] Proceeding 16A-0396E. In this study report, use of the term "utility generation resource" is meant to generally apply to resources that are under the control of, or contracted to, the utility and are used to meet the bulk electrical power needs of its customers. Utility generation resources may be owned by the Company, an independent power producer, municipality, or other entities. Utility generation resources do not include behind-the-meter generation (e.g., "rooftop" solar) or community solar garden generators.

Table 3 Locations of 2023 Hydro, Solar, Wind and Storage Resources

	Resource	Utility Resource MW	BTM CSG MW
Hydro	MTN	35	
	NFR	23	
	WS	2	
	Total Hydro	60	0
Solar	MTN	72	17
	NFR[9]	50	680
	SFR[9]	1,023	
	SLV	136	35
	WS		55
	Total Solar	1,281	787
Wind	ERZ-1	1,385	
	ERZ-2	2,502	
	ERZ-3	237	
	Total Wind	4,124	0
Storage	MTN (Cabin Creek)	300	
	SFR (Solar Hybrid)	275	
	Total Storage	575	0

Study Methodology

Study Goals

The Company's goals in this study were to estimate the ELCC of:

1. The Company's portfolio of hydro, solar, wind, and storage resources assumed existing at the start of 2021,
2. The Company's portfolio of hydro, solar, wind, and storage resources assumed existing at the start of 2023,
3. Incremental solar and wind resources as a function of geographic location and penetration on both standalone and portfolio bases,[10] and,

[9] The 50 MW Titan Solar facility in the NFR (which serves as the resource for the Renewable*Connect program) and the 240 MW Bighorn Solar facility in the SFR (which will serve as the resource for the statutory contract with EVRAZ) are included in this table along with the utility generation resources.

[10] The Company's hydro portfolio consists of 19 units totaling 60 MW of primarily run-of-river and conduit resources with in-service dates that span from 1903 to 2015. The Company has only acquired 0.2 MW from hydro generation resources with an in-service date within the last 12 years. As the potential to add significant levels of new hydro

4. Incremental levels of storage resources on both standalone and portfolio bases with incremental wind and solar resources.

ELCC values for existing resources are used on the Company's loads and resources tables to determine the need for incremental resources in order to meet planning reserve reliability targets. ELCC values for incremental resources are used to evaluate the economic value (e.g., generation capacity credit) of proposed solar, wind, and storage projects.

Numerous studies, including the Company's prior ELCC studies, have illustrated the law of diminishing returns for the generation capacity credit attributable to higher penetrations of non-dispatchable generation.[11] That is, the value of capacity attributable to incremental solar or wind is less than the value of the capacity of the existing solar or wind. Thus, it is important when constructing resource portfolios designed to achieve reliable operations to capture these diminished ELCC values at higher penetrations.

Renewable Generation Resources

The Company's methodology in this ELCC study for the evaluation of hydro, solar, and wind resources follows the "Preferred Methodology" described in a 2011 Institute of Electrical and Electronics Engineers ("IEEE") publication[12] and the Effective Load Carrying Capability methodology described in a 2012 National Renewable Energy Laboratory ("NREL") publication.[13] Following the methodology in those publications, the steps the Company utilized to estimate the ELCC of existing generators were:

1. The LOLE of the base 2023 system model in PLEXOS, without the existing generators under study, was calculated for the annual study period (i.e., one of the annual periods from 2014-2019).[14]
2. If the LOLE from Step #1 was not equal to the reliability target of 1 hour in 10 years,[15] equal amounts of load were either added to or subtracted from each hour of the annual

resources as a utility generation resource is limited and the generation profile of new hydro generation is unknown, the Company did not evaluate ELCC values for incremental hydro resources in this study.

[11] See, for example, "Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California"; Mills and Wiser. LBNL-5445E, June 2012 and "Representation of Solar Capacity Value in the ReEDS Capacity Expansion Model"; Sigrin, Sullivan, Ibanez, and Margolis. Technical Report, NREL/TP-6 A20-61182, March 2014.

[12] "Capacity Value of Wind Power"; Keane, Milligan, Dent, Hasche, D'Annunzio, Dragoon, Holttinen, Samaan, Söder, and O'Malley. IEEE Transactions on Power Systems, Vol. 26, No. 2, May 2011.

[13] "Comparison of Capacity Value Methods for Photovoltaics in the Western United States"; Madaeni, Sioshansi, and Denholm. Technical Report, NREL/TP-6A20-54704, July 2012.

[14] LOLE calculations were conducted within a representation of the Company's portfolio of generators expected to exist at the start of 2023 in the PLEXOS software. PLEXOS is owned by Energy Exemplar Pty Ltd.

[15] 1 hour in 10 years = 0.1 hours per year = 0.00417 days/year.

study period (i.e., a parallel shift in load) until the reliability target for the base system was achieved.

3. The existing generators under study were added to the system model and the LOLE was recalculated.
4. Keeping the generators under study in the system model, a constant load was added to each hour.[16] The level of the constant load was adjusted and the resulting LOLE recalculated until the portfolio LOLE once again achieved the target reliability.
5. The amount of load added in Step #4 was the ELCC of the existing generators under study.

The Company's prior ELCC studies showed that the calculation of ELCC attributed to a portfolio of solar and wind generators can differ from the sum of the standalone ELCC calculations for the same solar and wind generators. In order to both: 1) capture any interactions between the Company's increasing portfolio of solar and wind generation resources on a portfolio-level calculation of ELCC, and 2) identify ELCC values for the individual groups of solar and wind resources evaluated, ELCC results for the individual groups of solar and wind resources were adjusted so that the sum of the individual ELCC results matched the portfolio ELCC results.

As the Company conducts its long-term planning operations consistent with Federal Energy Regulatory Commission ("FERC") orders regarding behind-the-meter generation,[17] it treats these generators consistent with other sources of generation. That is, it plans for its customers' entire native load and carries distribution-interconnected solar generation (e.g., behind-the-meter generation and community solar gardens generation) on its loads and resources table (reduced for their ELCC values) along with all other generation resources. Thus, an estimate of ELCC for these categories of solar generation are needed.

A similar study methodology was employed to evaluate incremental solar and wind generation resources; however, for incremental evaluations, the base portfolio of generation resources in the model required in Step #1 above included all existing hydro, solar, and wind generators at the start of 2023.

Energy-Limited Resources

Existing energy-limited resources include the Company's portfolio of: 1) time-limited, dispatchable, demand response resources, 2) the Cabin Creek pumped hydro facility, and 3) the storage components of those solar hybrid facilities (i.e., solar plus embedded battery storage) acquired through the 2016 ERP. Incremental energy-limited resources in this study report include standalone storage and solar hybrid facilities.

[16] The resulting LOLE in Step #3 was lower than the LOLE of the base system because an additional generator had been added increasing reliability, thus additional load must be added to increase LOLE.

[17] See, e.g., FERC Order on Rehearing in Dockets No. ER08-394-004 and ER08-394-005 (February 19,2009) at ¶15.

As demand response resources are treated as demand-side/load reduction resources on the Company's loads and resources table, ELCC values for the Company's portfolio of demand response resources are not presented in this study report. However, the existence of these resources in the Company's portfolio does impact the ELCC values attributable to the other supply-side, energy-limited resources on the Company's loads and resources table as described below. Thus, the existence of dispatchable demand response resources in the Company's portfolio impacts the calculations of ELCC for Cabin Creek and the existing solar hybrid storage resources, as well as any other incremental storage resources.

Storage-resource ELCCs were calculated using the methodology described in IEEE Transactions on Power Systems, Vol. 34, November 2019.[18] This methodology modifies the ELCC methodology described above by optimally allocating the limited capacity (MW capacity and MWh energy) of energy-limited resources to the highest loss of load probability hours available to the resource under evaluation. Energy-limited resources are evaluated sequentially; capacity from resources evaluated first is allocated so to maximize reduction in loss of load probability. Capacity from subsequent resources are allocated against the resulting hourly loss of load probability curve, again, to maximize reduction in loss of load probability. The result of the methodology is a marginal capacity credit curve with increasing penetrations of energy limited resources.

As ELCC calculations are conducted sequentially across resources, the order in which the resources are evaluated is important. The methodology is conducted against hourly net-load;[19] thus, before any energy-limited resources are evaluated, all renewable generation (both existing and incremental, if any) must be in the model. The solar component of solar hybrid facilities is included with all other solar resources in the model; the storage component of solar hybrid facilities is included with the energy limited resources.

In general, most storage resources can be cycled on a daily or somewhat less frequent basis;[20] however most dispatchable demand response resources, such as the Company's Interruptible Service Option Credit ("ISOC"), have much higher restrictions. If, for example, a 4-hour duration call on ISOC resources is assumed, 40-hour resources can only be called 10 times in a year. Also, much of the Company's demand response portfolio is only dispatchable during warm weather

[18] "Declining Capacity Credit for Energy Storage and Demand Response with Increased Penetration", Keith Parks, IEEE Transactions on Power Systems, Vol. 34, No. 6, November 2019. A copy of the accepted version of the paper is publicly available on the XcelEnergy.com website.

[19] Net-load is native load less non-dispatchable renewable generation. Native load is total customer load that the Company is obligated to serve regardless of whether any customer has behind-the-meter generation or subscribes to a community solar garden.

[20] For example, the Cabin Creek pumped hydro facility is typically cycled once per day, whereas the storage components of the solar hybrid facilities are expected to be closer to a 200 day/year equivalent cycle frequency based on limitations of the battery storage technology and restrictions under purchased power agreements.

months (i.e., Savers Switch and AC Rewards) and cannot be used to address high loss of load hours outside of those months.[21] For these reasons, the Company has adopted a methodology in which dispatchable demand response resources—which have a higher level of restricted usage as compared to storage resources—are the first energy limited resources evaluated.

The order in which the existing energy limited resources was studied is shown in Table 4 below. Any incremental storage resources were evaluated after the existing 275 MW of Solar Hybrid Storage resources shown in Table 4.

Table 4 Evaluation Order for Energy Limited Resources

Order	Resource	Resource Capacity (MW)	Modeled Duration (hours)
1	40-Hour ISOC	12	4
2	80-Hour ISOC	61	4
3	160-Hour ISOC	117	4
4	60-Hour Summer Only	266	4
5	60-Hour Day Ahead	105	4
6	Cabin Creek	300	5
7	Solar Hybrid Storage	275	4

Generation Data Sources

Hourly, historical hydro, solar, and wind generation data were obtained for the years 2014-2019 in order to conduct the study of existing and incremental generators. Other sources of hourly data were utilized in the incremental ELCC analyses for some locations, as discussed below.

<u>Hydro</u>

Interval generation data were obtained from revenue meters located at the various hydro generation facilities in the Company's portfolio.

<u>Solar</u>

Behind-the-meter – Interval generation data included meter data from net-metered customers on demand-rate tariffs who have both interval load and solar generation meters installed. Interval generation data were also collected from the Company's solar sample data set which includes

[21] This observation on the seasonal availability of certain demand response resources could have significant implications in the future as incremental additions of renewable generation (primarily solar) push the Company's net load peaks into the winter months.

generation meter data from over 400 net-metered customers with customer-sited solar across the Company's retail service territory. Meter data were aggregated by geographic location, tracking capability, and facility nameplate size. Hourly data from the meter data obtained were used as proxies to create generation curves for the total MW installed in each geographic location and tracking capability. Hourly generation curves were grossed up by 6.1% to model the generation resources consistent with the native load data as discussed in the Load Data section below.

Community solar gardens – Interval generation data were obtained from revenue meters located at roughly 60 community solar garden facilities interconnected to the Company's distribution network across its retail service territory. Hourly data from the meter data obtained were used as proxies to create generation curves for the total MW installed in each geographic location and tracking capability. Hourly generation curves were grossed up by 1.7% to model the generation resources consistent with the native load data as discussed in the Load Data section below.

Utility generation – Interval generation data were obtained from revenue meters located at seven solar facilities located in the Northern Front Range, Southern Front Range, and San Luis Valley. Data were adjusted to be gross of any actual historical curtailment.[22] The Company also utilized the National Renewable Energy Laboratory's Solar Advisor Model[23] and hourly meteorological data for 2014-2019 from the National Solar Radiation Database[24] to create hourly generation data for utility solar resources in geographic areas where the Company did not have generation meter data from one-axis utility generation-quality resources (e.g., the Western Slope and Southeast Colorado/ERZ-3). Nearly all existing utility solar generation is, and all incremental utility solar generation was assumed to be, from one-axis tracking facilities.[25]

Wind

Interval generation data were obtained from revenue meters located at sixteen wind facilities located in ERZs 1, 2 and 3. Data were adjusted to be gross of any actual historical curtailment.

Hourly wind generation data for incremental ERZ-5 wind generation were created from interval wind speed data measured at the 60 MW Peak View Wind Project located approximately 35 miles south of Pueblo.[26] These wind speed data were processed through a wind turbine power curve representative of current technology to create the hourly data.

[22] During real-time operations, the Company may curtail wind and solar generation resources to balance load and generation and in response to transmission operation directives.

[23] The Solar Advisor Model and its description is available at: sam.nrel.gov.

[24] The National Solar Radiation Database can be accessed at: nsrdb.nrel.gov.

[25] The Company currently purchases generation from a single, 30 MW two-axis tracking photovoltaic facility.

[26] The wind speed data were provided by Black Hills Energy. The Company is grateful for the use of these data.

Load Data Sources

As one goal of the study was to determine ELCC values for all existing renewable generation resources on the system (including behind-the-meter solar generation), the Company used hourly native load in the PLEXOS model. Native load is calculated from obligation load which is measured at transmission voltage levels. Hourly native load for the period 2014-2019 was calculated by adding hourly behind-the-meter solar generation (grossed up by assumed average line losses of 6.1%),[27] hourly solar garden generation (grossed up by assumed average line losses of 1.7%),[28] and hourly impacts of calls on demand response programs to, and subtracting charging MW for Cabin Creek from, the base obligation load data.

Study Results

Existing Hydro Resources

The evaluation of hydro resource ELCC was conducted on a standalone basis given the small MW of installed generation and the low likelihood of acquiring significant MW of new hydro generation in the next competitive solicitation. The annual and average results for the portfolio of hydro resources expected to be operational at the start of 2023 are shown below in Table 5.

Table 5 Average ELCC for Hydro Generation Resources

Year	ELCC
2014	33.5%
2015	38.1%
2016	64.1%
2017	76.0%
2018	61.9%
2019	58.5%
Average	55.4%

Existing Solar, Wind, and Storage Resources

Results for the Company's existing solar, wind and storage resources for the 2021 and 2023 portfolios are shown in Table 6 and Figure 2 as an average of the six years of historical data.[29]

[27] 6.1% average line losses are the installed MW-weighting of net-metered generation interconnected at primary and secondary voltage levels.

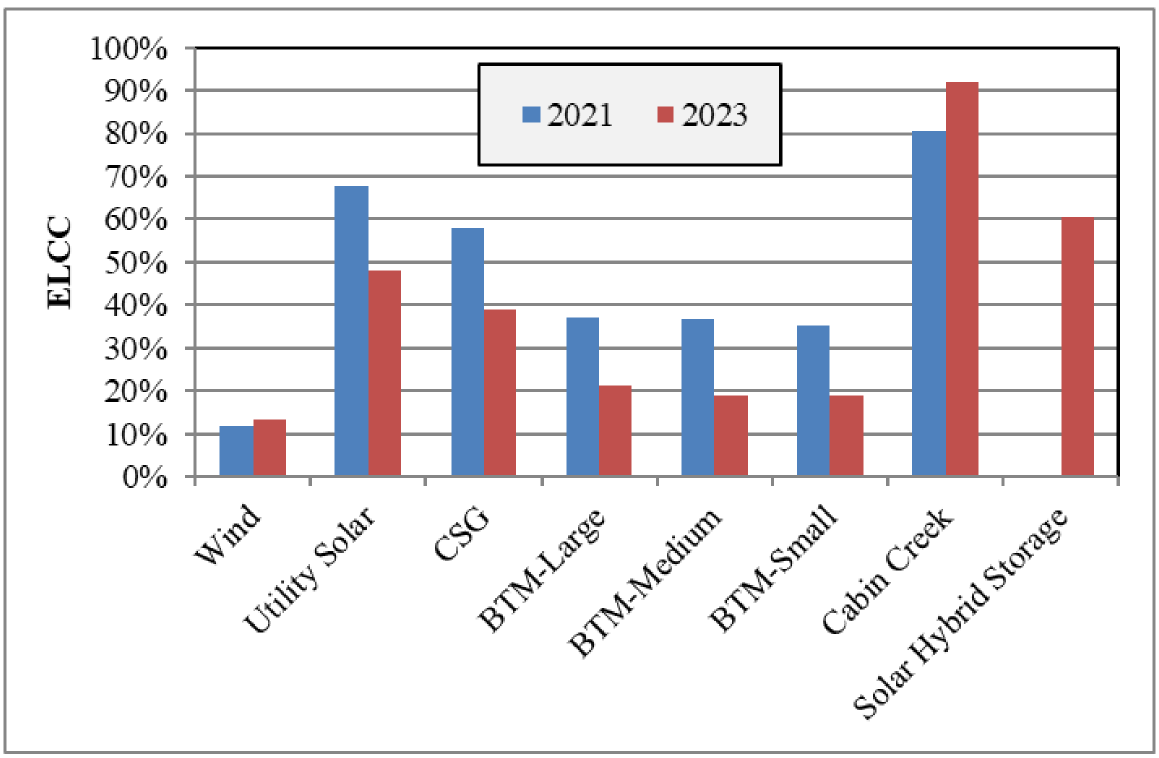
[28] All solar garden facilities were assumed to interconnect at primary distribution voltage; 1.7% is avoided average transmission voltage line losses.

[29] Results in Table 6 are those evaluated after the adjustment required so that the sum of the standalone wind and solar ELCCs equal the portfolio ELCC. Adjusted and unadjusted portfolio and standalone ELCC results for the Table 6 resources for all years (2014-2019) are shown as Tables A-1 and A-2 in Appendix A.

Table 6 ELCC Results for Existing Wind, Solar and Storage Resources[30]

	2021 Portfolio			2023 Portfolio		
	Nameplate (MW)	ELCC	Capacity Credit (MW)	Nameplate (MW)	ELCC	Capacity Credit (MW)
Wind	4,124	12%	490	4,124	13%	553
Utility Solar	306	68%	207	1,281	48%	614
CSG	138	58%	80	196	39%	76
BTM-Large	53	37%	20	77	21%	16
BTM-Medium	111	37%	40	133	19%	25
BTM-Small	301	35%	105	383	19%	73
Cabin Creek	300	81%	242	300	92%	275
Solar Hybrid Storage				275	61%	166
	5,332		1,184	6,767		1,799

Figure 2 ELCC Results for Existing Wind, Solar and Storage Resources



As discussed previously, the 2021 and 2023 portfolios have the same level of wind generation, but the 2023 portfolio has over 1,100 MW of additional solar generation. The impact of this additional

[30] CSG = community solar garden; BTM = behind-the-meter solar.

solar generation is an increase of 62 MW of capacity credit attributable to the wind portfolio and an increase of 33 MW of capacity credit attributable to Cabin Creek. However, the incremental solar has a profound reduction in the % ELCC attributable to the solar portfolio. The average % ELCC attributable to utility solar shows an approximate 30% reduction, CSG has an approximate 33% reduction, and behind-the-meter has an approximate 47% reduction.[31] The % ELCC reductions are large enough for BTM and CSG that the MW amounts of generation capacity credit are less in the 2023 portfolio than in the 2021 portfolio, even though the 2023 portfolio has 186 MW more installed CSG and BTM solar.

Comparison of Average to Annual Results

The information shown in Table 6 and Figure 2 is based on an average of the results for the six years studied. A more conservative application of the study results from a reliability perspective could select the historical year with the lowest level of total portfolio ELCC for use on the loads and resources table. For both the 2021 and 2023 portfolios, results utilizing 2017 data were the lowest of the six years. For the 2021 portfolio, the combined renewable and storage ELCC results for 2017 is 110 MW lower than the six-year average result. For the 2023 portfolio, the combined renewable and storage ELCC results for 2017 are 220 MW lower than the six-year average result. As the average of the six years of ELCC results is more consistent with the Planning Reserve Margin study methodology utilized for the Company's 2021 ERP, the Company utilizes the average ELCC results from this study on its loads and resources table.

Incremental Standalone Solar, Wind, and Storage Resources

Solar

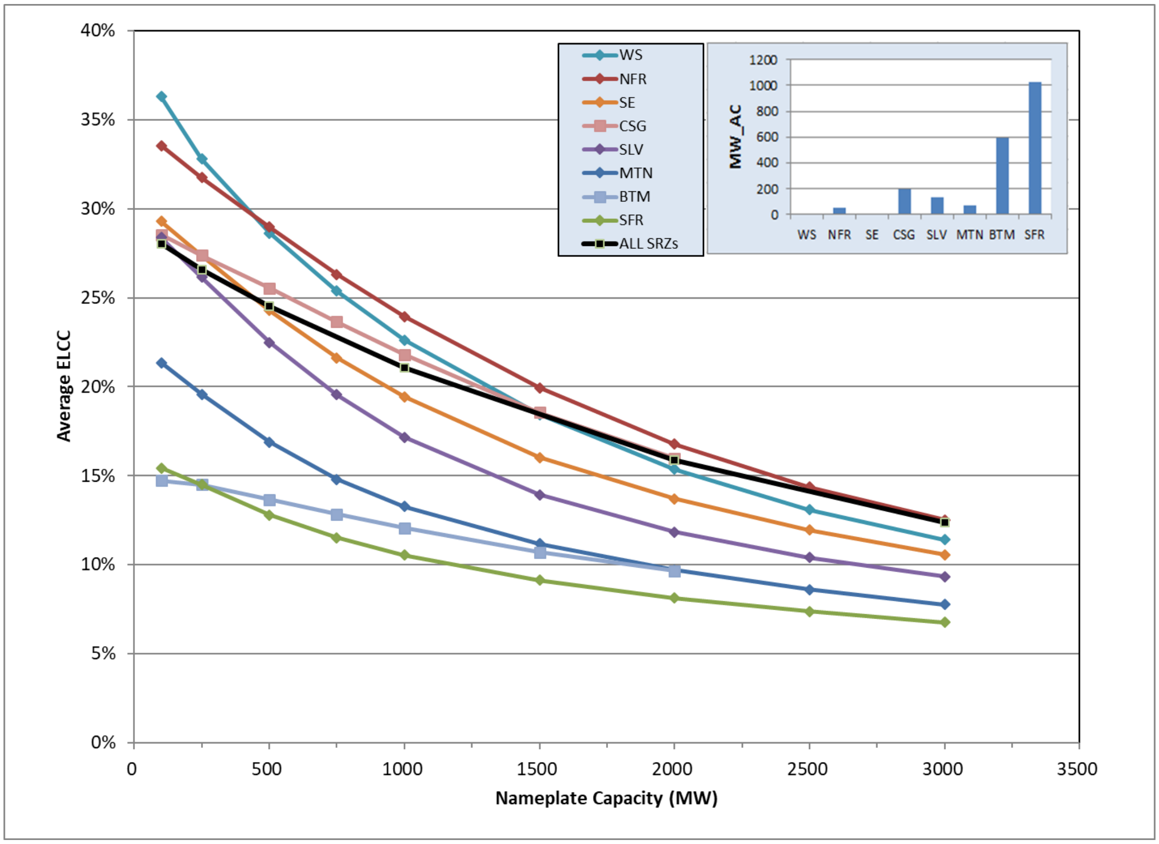
Figure 3 shows the average ELCC that would apply to a standalone addition of solar at six solar resource zones and for additional BTM and CSG solar.[32] Also included in Figure 3 are the expected MW of solar at the beginning of year 2023 for these eight categories; these are the starting MW to which incremental solar were added in the study. In general, the lowest levels of ELCC attributable to additional solar resources are in those locations or for those resource types with the current highest level of penetration (e.g., BTM and SFR).[33]

[31] Note that the 2021 portfolio of behind-the-meter solar has a similar % ELCC as was found in the Company's 2016 solar ELCC study; 37% in the prior study and 36% here.

[32] A complete set of annual incremental and average ELCC results at each location and at each level of incremental solar studied are included as Table A-3 in Appendix A.

[33] In addition to the observation that most BTM solar is installed in a relatively small geographic area of Colorado, virtually all BTM solar is installed in fixed orientations; incremental ELCC assigned to solar installed in a tracking configuration as compared to fixed orientations has been documented in prior ELCC studies. Additionally, many BTM systems may be oriented in sub-optimal directions and/or experience partial shading during many hours which can further limit its generation during high loss of load probability hours.

Figure 3 Average ELCC Results for Incremental Standalone Solar



The plot labelled "All SRZs" in Figure 3 is the ELCC values resulting from the average of the six solar resource zone hourly generation values. A comparison of these diversified ELCC results to the standalone ELCC results shows that, in general, a simple combination of the standalone ELCC results is a good approximation for the diversified ELCC results at lower penetration levels; however, at higher penetration levels the diversity benefits of a well-diversified solar portfolio are evident.

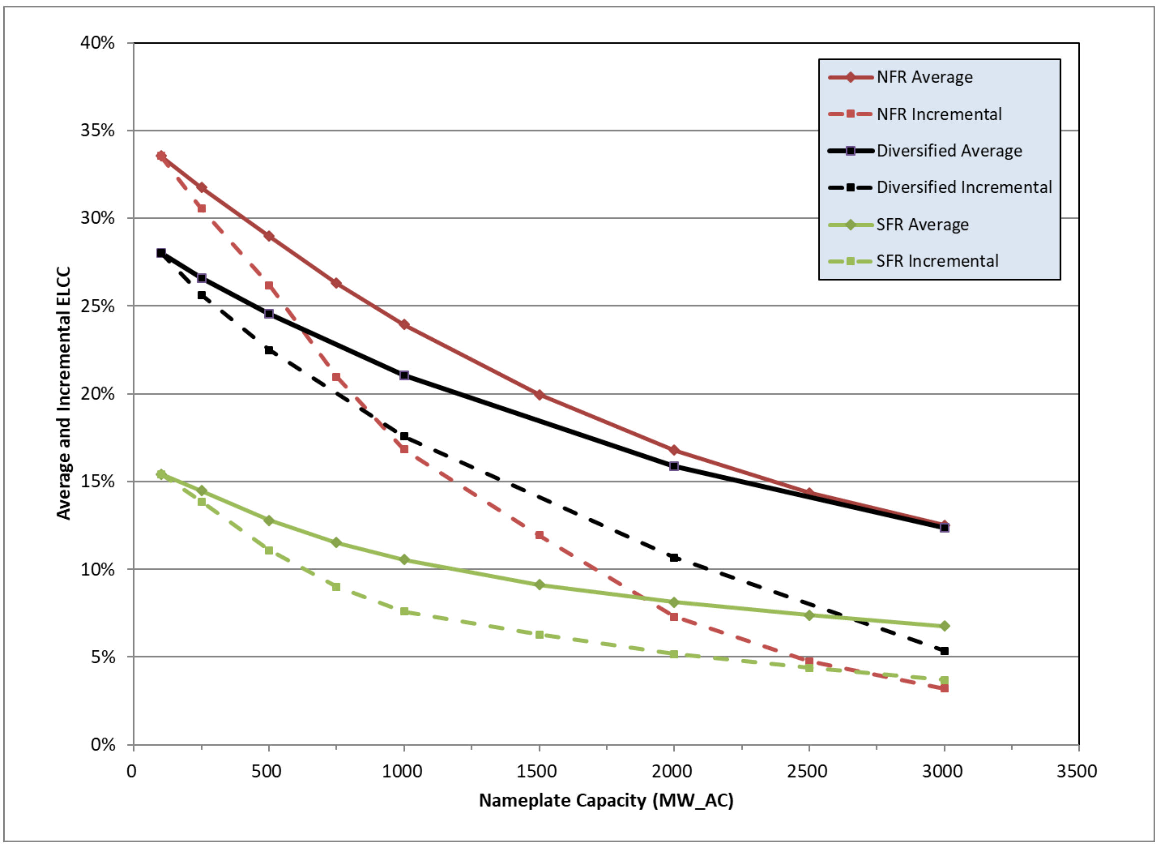
Declining average ELCC is the impact of declining incremental ELCC. As shown in prior studies, incremental ELCC falls relatively quickly with increasing penetrations.[34] This is a result of the non-dispatchable nature of the solar resource. In the limit, with sufficient additions of solar

[34] In addition to the Company's prior ELCC study reports, see in addition: "Comparing Capacity Value Estimation Techniques for Photovoltaic Solar Power." Madaeni, S. H., R. Sioshansi, and P. Denholm.. (2013) IEEE Journal of Photovoltaics, Vol. 3(1): 407-415.

generation, ELCC values for incremental solar will go to zero due to the diurnal nature of the resource.[35]

Figure 4 shows the average and incremental ELCC for NFR and SFR and for the Diversified Solar proxy. Figure 4 shows the benefits of solar resource geographic diversity in reducing the declines in ELCC with increasing penetrations; specifically, the average and incremental ELCCs for the Diversified solar portfolio remain above those for either the NFR or SFR. However, at the highest penetrations studied, the incremental ELCC of the Diversified portfolio approaches that of the other two resources; that is, at 3,000 MW of incremental solar, ELCC for NFR, SFR or Diversified Solar is ~5%.

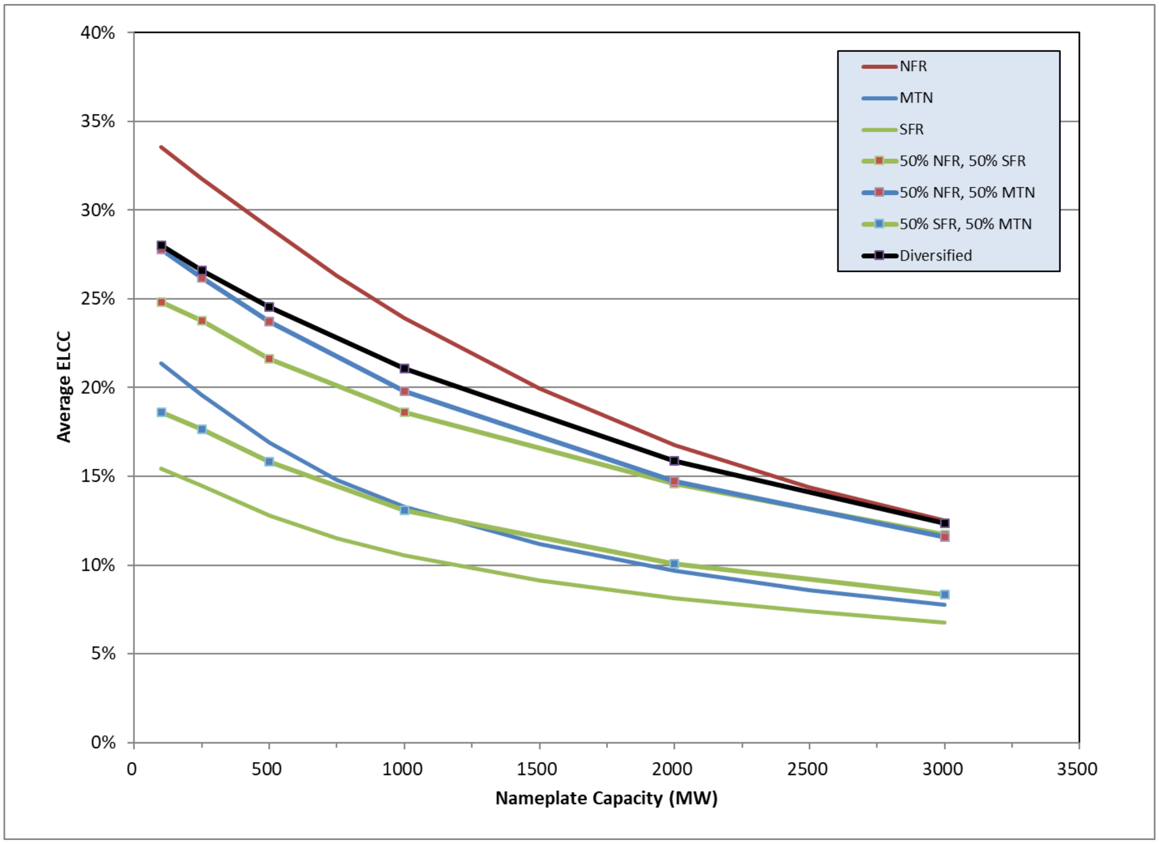
Figure 4 Average and Incremental ELCC Results for Incremental Standalone Solar



[35] The Company has loads at all hours of the day, but solar generation stops with nightfall. As the high daytime LOLP hours are reduced by daytime solar generation, the highest nighttime LOLP hours become the dominant reliability risk and cannot be reduced with incremental solar generation.

Figure 5 shows the impact on ELCC from various 50/50 blends of solar at the MTN, NFR, and SFR locations.[36] At low penetrations of incremental solar, average ELCC for the 50/50 blends are well approximated by an average of the component ELCCs. However, at higher penetrations, diversity value within the 50/50 blends results in notably higher ELCC values than a simple average of the component ELCCs.

Figure 5 Average ELCC Results for Combinations of Incremental Standalone Solar

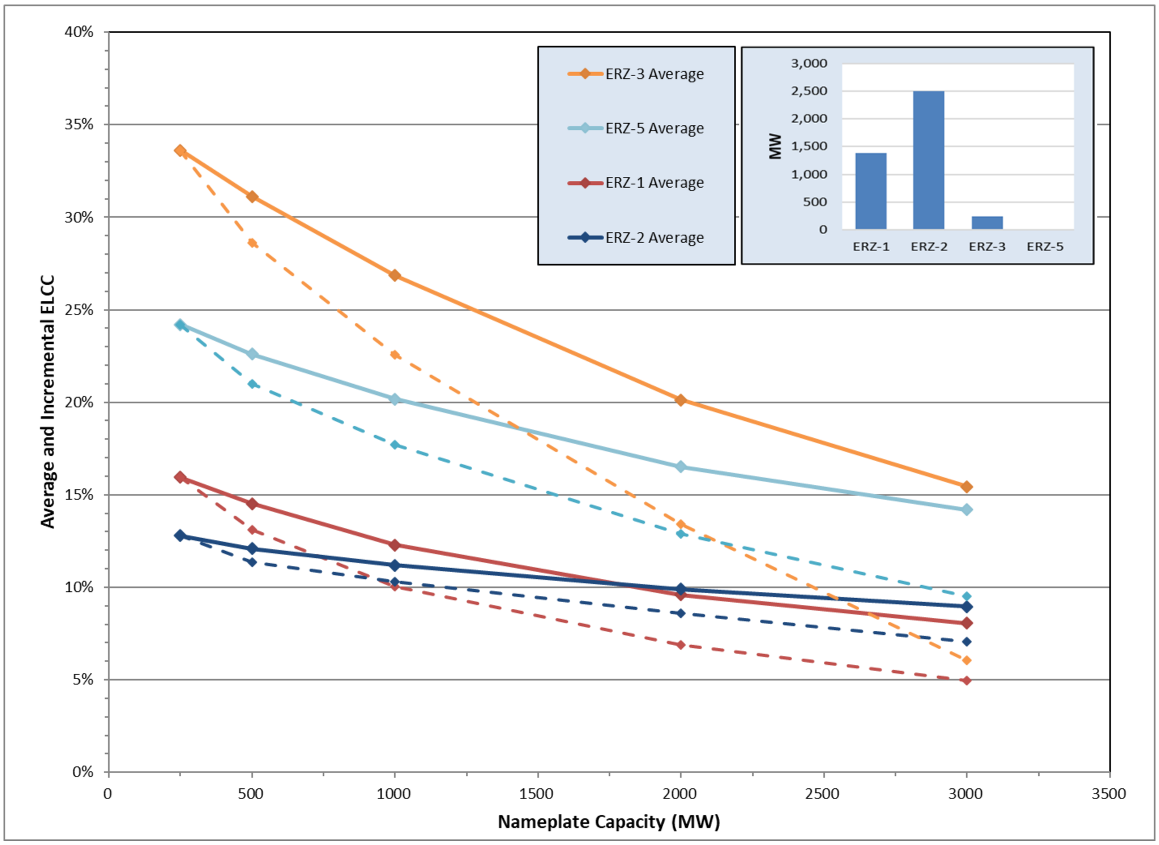


[36] ELCC results for the 50/50 blends were calculated by evaluating hourly generation curves that were a 50/50 blend of the component hourly generation curves, not simply an average of the component ELCC results. A complete set of annual incremental and average ELCC results for incremental solar shown in Figure 5 is included as Table A-4 in Appendix A.

Wind

Figure 6 shows the average and incremental ELCC that would apply to a standalone addition of wind at four energy resource zones.[37] Also included in Figure 6 are the expected MW of wind at the beginning of year 2023 for these four categories; these are the starting MW to which incremental wind was added in the study. Consistent with the standalone solar results, the lowest levels of ELCC attributable to incremental wind resources are in those locations with the highest current levels of penetration.

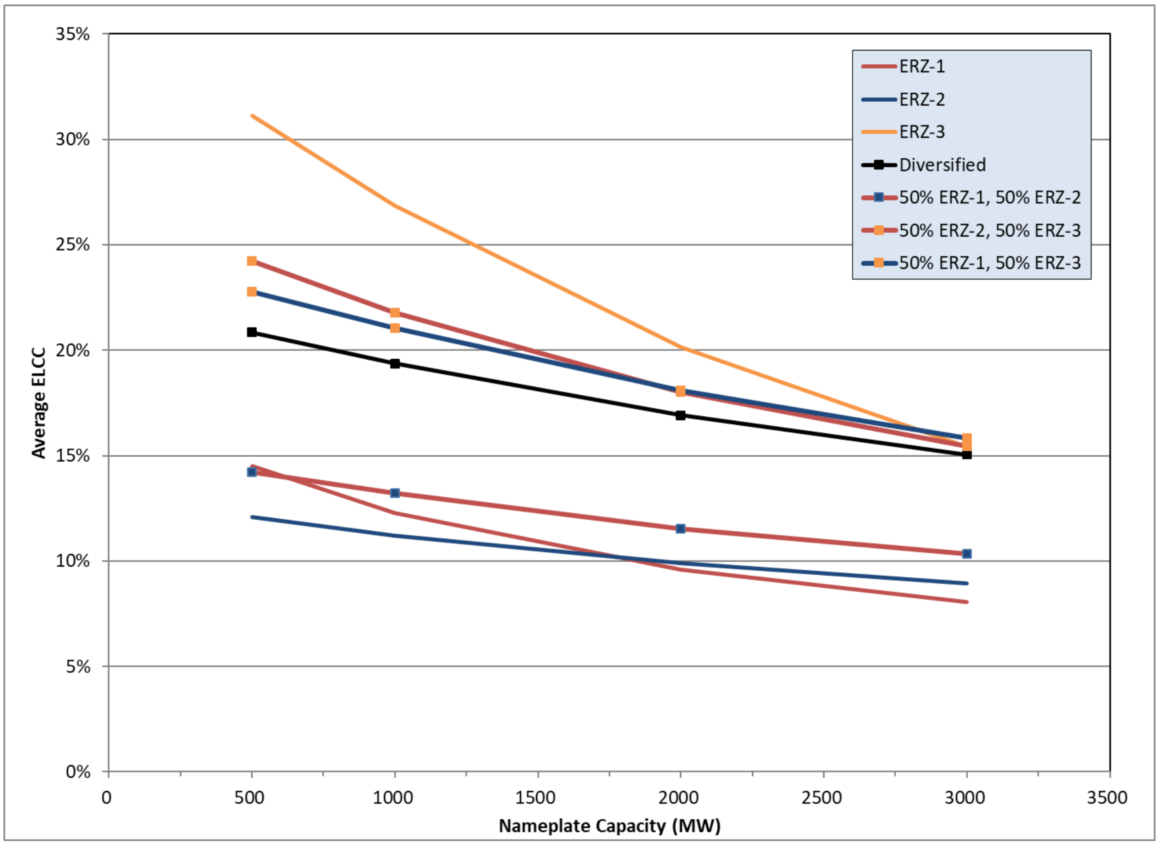
Figure 6 Average ELCC Results for Incremental Standalone Wind



[37] A complete set of annual incremental and average ELCC results at each location and at each level of incremental wind studied is included as Table A-5 in Appendix A. Note that for ERZ-5, the results shown are for wind facilities exhibiting an hourly generation curve with a 50% NCF consistent with the assumptions for incremental wind at the other three ERZs. Note, however, that the raw wind speed data utilized in the creation of the hourly generation curves for ERZ-5 are more consistent with a wind facility with a 44% NCF. ELCC results using a 44% NCF hourly curve were approximately 25% lower than the 50% NCF results. These 44% NCF results are also included in Table A-5.

Figure 7 shows the impact on ELCC from various 50/50 blends of wind at the ERZ-1, ERZ-2, and ERZ-3 locations as well as a Diversified portfolio of wind calculated from the simple average of the three wind resources hourly generation data.[38] At low penetrations of incremental wind, average ELCC for the 50/50 blends are well approximated by an average of the component ELCCs. However, at higher penetrations, diversity value within the 50/50 blends results in notably higher ELCC values than a simple average of the component ELCCs.

Figure 7 Average ELCC Results for Combinations of Incremental Standalone Wind

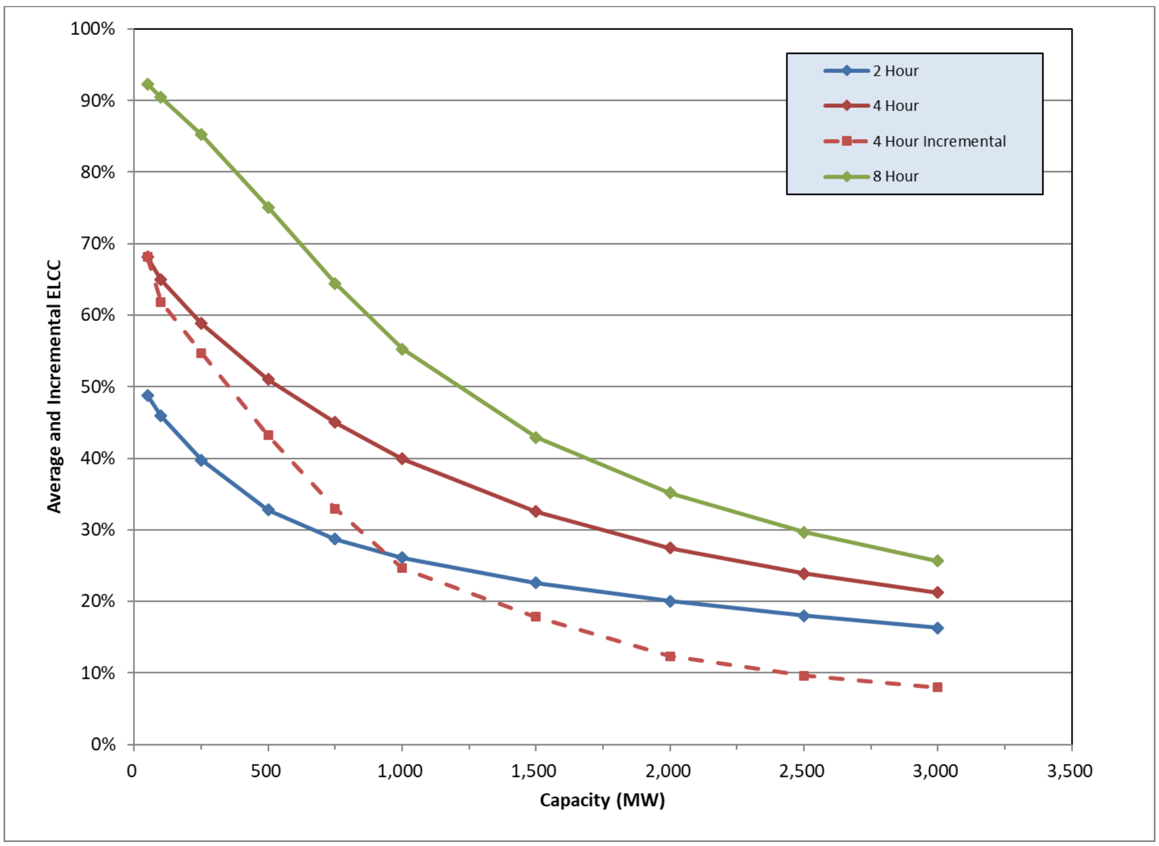


[38] A complete set of annual incremental and average ELCC results for those shown in Figure 7 is included as Table A-6 in Appendix A.

Storage

Figure 8 shows the average and incremental ELCC that would be attributed to incremental standalone storage resources at 2, 4, and 8-hour durations.[39] Declining ELCC values for storage are to be expected and are consistent with findings in other studies.[40] Initially, short duration storage is effective in reducing peak loss of load probability hours given the needle peaks in net load resulting, in part, from the impacts of non-dispatchable wind and solar generation. However, as the sharp peaks in LOLP are reduced to more broad plateaus through the allocation of storage MW to the peaks, the limited amounts of stored generation must be dispersed across more hours resulting in lower MW levels of LOLP reduction. This effect for 4-hour duration storage is illustrated in a declining incremental ELCC with increasing penetrations as seen in Figure 8.

Figure 8 Average and Incremental ELCC for Incremental Standalone Storage



[39] A complete set of annual incremental and average ELCC results for those shown in Figure 8 is included as Table A-7 in Appendix A.

[40] See for example, "Capacity and Reliability Planning in the Era of Decarbonization: Practical Application of Effective Load Carrying Capability in Resource Adequacy," N. Schlag, Z. Ming, A. Olson, L. Alagappan, B. Carron, K. Steinberger, and H. Jiang. Energy and Environmental Economics, Inc., Page 6, Aug. 2020 and "Energy Storage and Hybrid Resources: Resource Adequacy Concerns", IEEE RAWG. Page 9, August 2020, Astrape Consulting.

As discussed in the methodology discussion, the ELCC calculations for energy storage are conducted using a process that calculates the maximal ELCC value to the given resource given the perfect foresight and optimal discharge available in the computer models. Thus, the values in Figure 8 and Table A-7 should be interpreted to be at the higher end of ELCC values possible; incomplete real-time information, sub-optimal charge and discharge decisions, and actual availability of the resource would be expected to reduce the reliability contributions available from actual storage devices from the values calculated here.

As discussed earlier, incremental ELCC for solar generation resources should be expected to approach 0% given the diurnal nature of the solar resource. For an energy-limited resource such as storage, incremental ELCC could be < 0% unless beneficial charge and discharge dispatch decisions are made. Charging a storage device increases load on the electric system and thus, increases LOLP in those charging hours; if the increase in LOLP from charging is greater than the decrease in LOLP from discharging, an overall decrease in system reliability will result. Such a result would show up as a negative ELCC calculation. [41]

Incremental Portfolios of Solar, Wind, and Storage Resources

<u>Solar and Wind</u>

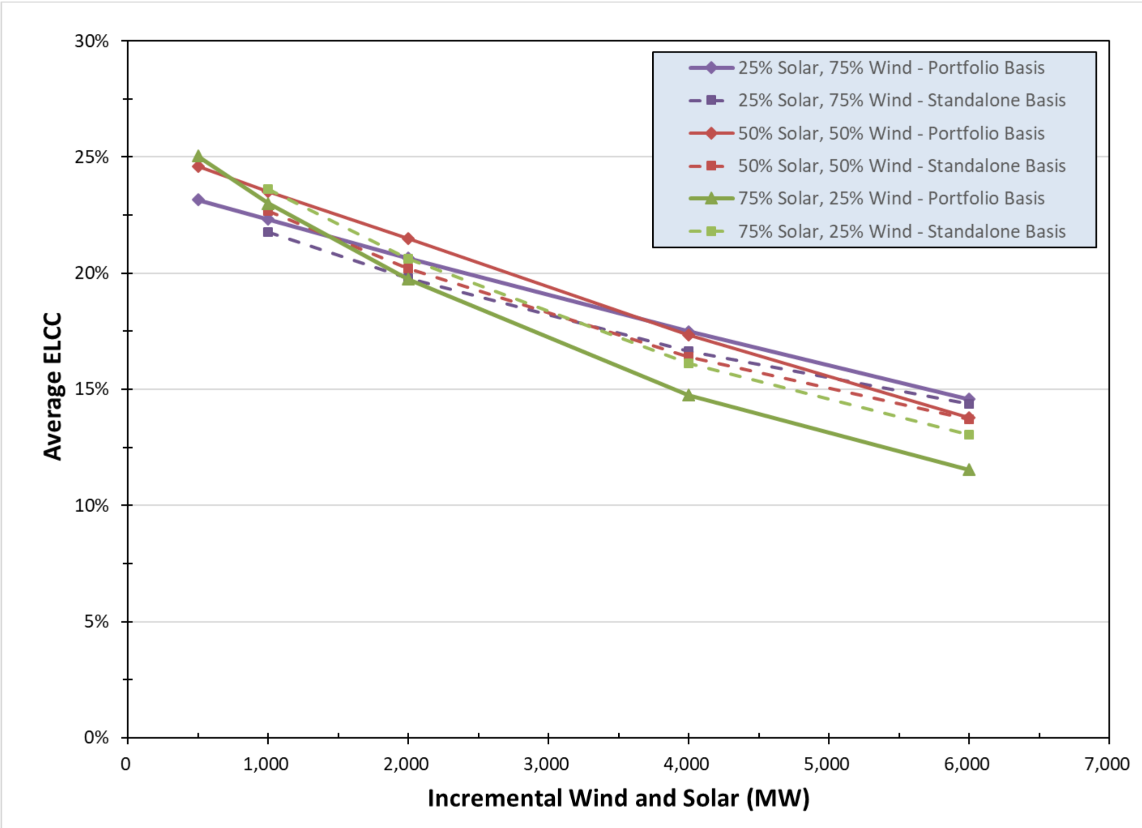
Figure 9 shows the average ELCC values attributable to three portfolios of well-diversified solar and wind; portfolios were evaluated at 25/75, 50/50, and 75/25 MW-weighted blends of solar and wind.[42] Figure 9 also shows the ELCC values that result from a simple combination of the standalone diversified solar and wind ELCC values shown previously in Figures 3 and 7.[43] These two methodologies for calculating a portfolio-level ELCC of a blend of solar and wind resources generally result in similar values across the incremental solar and wind MW studied. However, portfolios with a greater amount of solar show that Standalone Basis values exceed the Portfolio Basis values; balanced and wind-heavy portfolios show that Standalone Basis values are lower than the Portfolio Basis values.

[41] A more commonly understood corollary to such an observation is the negative impact inopportune storage/EV charging can have on system reliability if it occurs during system load peaks.

[42] A complete set of annual incremental and average ELCC results for those shown in Figure 9 is included as Table A-8 in Appendix A.

[43] The Portfolio Basis ELCC values are the result of an ELCC analysis on an hourly generation curve that is the combination of the hourly generation curves of the underlying generators; e.g. 50% of a well-diversified solar generation curve and 50% of a well-diversified wind generation curve. The Standalone Basis ELCC values are the blended average of the ELCC values of the underlying generators; e.g. 50% of the well-diversified solar ELCC result and 50% of the well-diversified wind ELCC result.

Figure 9 Diversity Benefit across Combinations of Wind and Solar



<u>Solar Under Wind</u>

One concept of increasing transmission load factor with renewable generation is to examine co-located solar and wind generation units utilizing the same interconnection equipment. In order to determine the impact on portfolio ELCC for such a configuration, two different geographical pairings—NFR solar under ERZ-2 wind and SE solar under ERZ-3 wind—were examined. The primary assumption made was that the interconnection was sized to the wind farm nameplate MW and generation curtailments would occur in any hour when the combination of wind and solar generation exceeded that limit. Wind nameplates of 250, 500, and 1,000 MW were examined with incremental MW of solar at 25%, 50%, 75%, and 100% of wind nameplate MW.

Results for the two pairings examined are in Table 7 below. In general, the ELCC diversity benefit of solar and wind was larger than any reduction in ELCC due to interconnection limitations; that is, Incremental Limited ELCCs were slightly greater than the sum of Standalone ELCCs. For both the NFR/ERZ-2 and SE/ERZ-3 pairings, annual % curtailments remained fairly modest (i.e., 10%

or less) up to 100% solar additions.[44] For the NFR/ERZ-2 pairing, essentially no loss in ELCC was noted between the Interconnection Limited results and the Not Interconnection Limited results. For the SE/ERZ-3 pairing, larger differences between the Interconnection Limited and Not Interconnection Limited ELCC calculations were noted at higher solar loadings, but the differences remained below ~ 4 percentage points.

Table 7 Solar under Wind ELCC Results

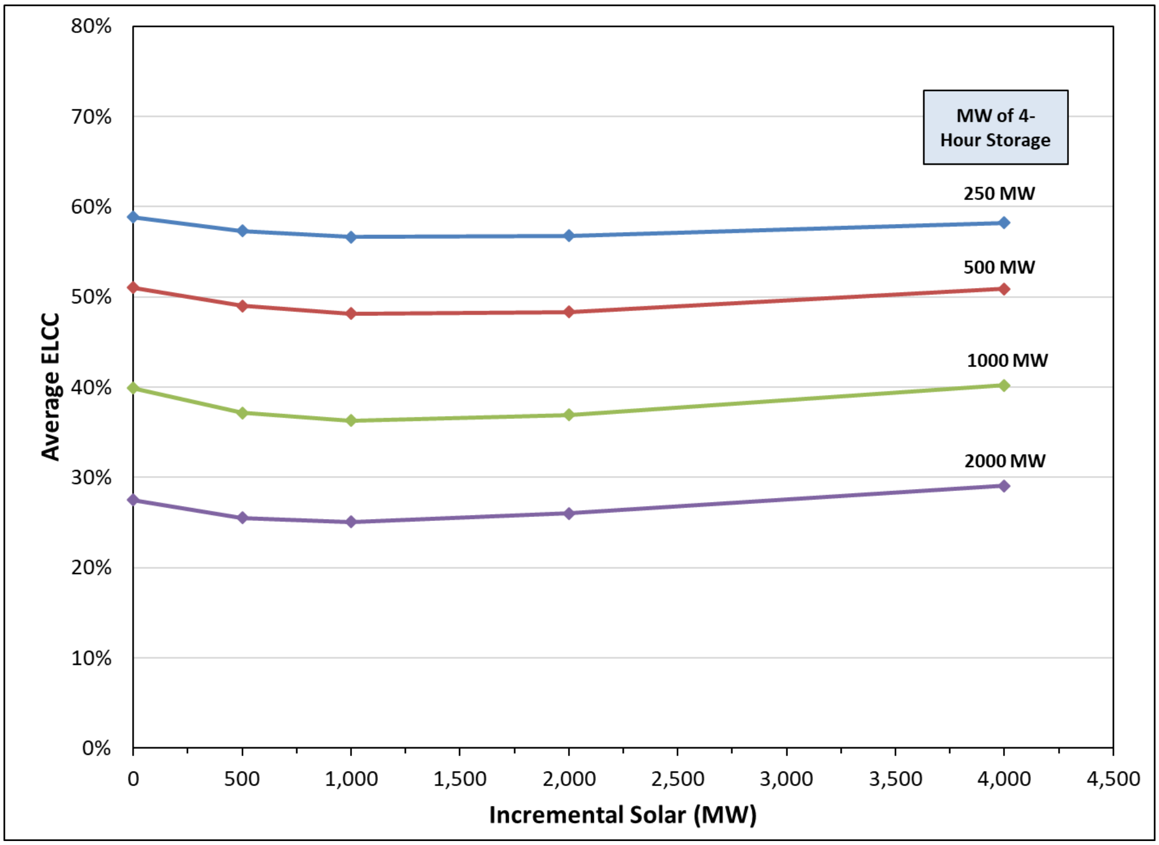
				Average ELCC (% of Total MW)		
	Incremental Wind (MW)	Incremental Solar (MW)	Annual Curtailment as % of Total Unlimited	Sum of Standalone Generation	Interconnection Limited	Not Interconnection Limited
NFR Solar and ERZ-2 Wind	250	0	0.0%	12.8%	12.8%	12.8%
	250	63	0.6%	16.8%	16.9%	17.1%
	250	125	2.6%	19.2%	19.8%	19.7%
	250	188	5.8%	20.7%	21.6%	21.4%
	250	250	10.1%	21.6%	22.5%	22.6%
	500	0		12.1%	12.1%	12.1%
	500	125		16.0%	16.6%	16.6%
	500	250		18.2%	19.2%	19.1%
	500	375		19.3%	20.5%	20.5%
	500	500		19.8%	21.2%	21.2%
	1000	0		11.2%	11.2%	11.2%
	1000	250		15.0%	15.9%	15.8%
	1000	500		16.7%	17.9%	17.9%
	1000	750		17.1%	18.6%	18.6%
	1000	1000		16.9%	18.5%	18.5%
SE Solar and ERZ-3 Wind	250	0	0.0%	33.6%	33.6%	33.6%
	250	63	0.6%	32.9%	33.1%	33.1%
	250	125	2.4%	32.1%	32.3%	32.5%
	250	188	5.3%	31.3%	31.4%	31.7%
	250	250	9.4%	30.5%	30.2%	31.0%
	500	0		31.1%	31.1%	31.1%
	500	125		30.7%	31.1%	31.1%
	500	250		29.9%	30.4%	31.1%
	500	375		28.8%	29.4%	30.8%
	500	500		27.7%	28.2%	30.5%
	1000	0		26.9%	26.9%	26.9%
	1000	250		27.0%	27.7%	27.5%
	1000	500		26.0%	27.2%	27.7%
	1000	750		24.6%	25.9%	27.6%
	1000	1000		23.1%	24.5%	27.2%

[44] Note that % curtailment is a function of the combined wind and solar hourly generation curves. As the same wind and solar generation unitized curves were used for each case in the study, the % curtailment is not a function of the Incremental Wind MW. As a result, Annual Curtailments as % of Total Unlimited values are only shown once for each level of Incremental Wind in Table 7 and not shown three times for each pairing.

<u>Solar and Storage</u>

To examine the interrelation between incremental storage and incremental solar generation, incremental levels of diversified solar were added to the model and then the ELCC of incremental levels of storage (250, 500, 1000, and 2000 MW) at the incremental solar levels were calculated. As discussed in the methodology section, incremental storage ELCC values were calculated after capacity from existing DR and storage resources was first allocated. Average ELCC results are shown in Figure 10.[45]

Figure 10 Average ELCC for 4-Hour Duration Storage with Incremental Diversified Solar



[45] The average ELCC values for 4-hour duration storage shown at 0 MW of Incremental Solar in Figure 10 are the same values as shown in Figure 8. A complete set of annual incremental and average ELCC results for those shown in Figure 10 is included as Table A-9 in Appendix A.

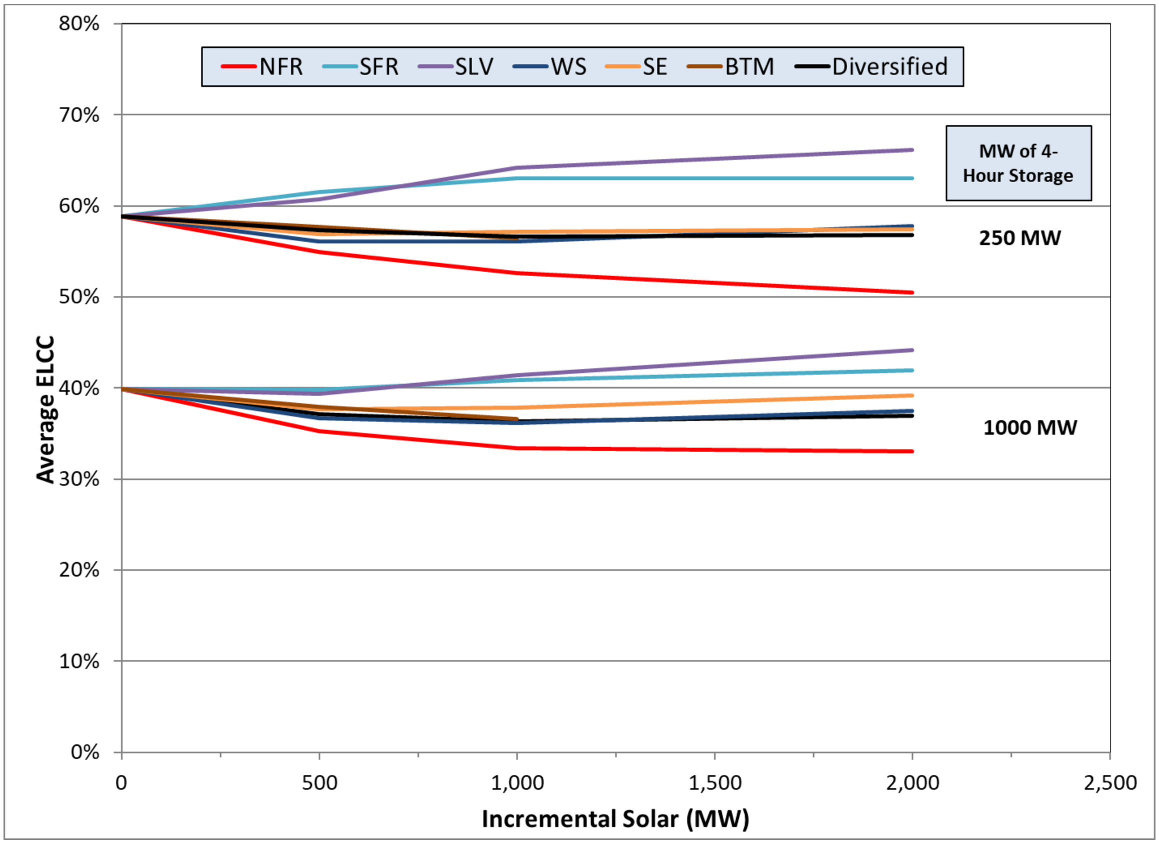
At each level of incremental storage examined, the graphs show a gradual decline in storage ELCC for the first ~1,000 MW of incremental solar and then a gradual increase in storage ELCC as more solar is added.[46] It appears that a minimum amount of incremental solar must be added to the current portfolio to create sufficiently "peakiness" (sharp net-load peaks) so that incremental storage ELCC can increase above the ELCC attributable to standalone storage with no incremental solar.

Figure 11 shows the average ELCC results when calculated for resource zone specific solar instead of diversified solar.[47] A divergence in results from the diversified solar results for incremental NFR as compared to incremental SLV and SFR solar is apparent. Results are likely impacted by the interplay between existing levels of solar in each zone, the inherent "peakiness" of each solar resource zone's hourly generation profiles, and that generation profile's interaction with net load profiles. There is a wider dispersion in average storage ELCC with incremental resource zone-specific solar at low levels of incremental storage than at higher levels of incremental storage. That is, there exists a wider range of average ELCC at 2,000 MW of incremental solar for 250 MW of storage than exists for 1,000 MW of storage.

[46] These results are similar to those found in study results elsewhere. See, for example, "The Potential for Battery Energy Storage to Provide Peaking Capacity in the United States", *Renewable Energy*, 2019, Pages 10-14. Denholm, Numemaker, Gagnon, and Cole, National Renewable Energy Laboratory. Available at: https:/doi.org/10.1016/j.renene.2019.11.117.

[47] A complete set of annual incremental and average ELCC results for those shown in Figure 11 is included as Table A-9 in Appendix A.

Figure 11 Impact of Solar Location on 4-Hour Duration Battery Average ELCC



Standalone Storage vs Solar Hybrid Storage

Storage resources co-located with solar generation can currently be eligible for the Federal Investment Tax Credit ("ITC") if at least 75% of the charging energy comes from the solar resource;[48] standalone storage is not currently eligible for the same ITC. Thus, there exists a tax incentive and potential cost savings to co-locate storage and solar resources. However, a co-located solar with storage ("solar hybrid") facility might provide a different level of system reliability than the same MW of solar and same MW/MWh of storage not co-located and not subject to ITC-induced or transmission interconnection operational limitations.

In order to estimate the potential reduction in ELCC, it was assumed for the solar hybrid case that the transmission interconnection was limited to the solar MW nameplate and that all charging energy came from the solar resource. The target level of incremental solar (based on the diversified

[48] The tax credit is proportional to the amount of solar generation used for charging between 100% and 75% and then is zero if less than 75% of annual charging energy comes from the solar resource. As the tax credit recapture period is 5 years, it is generally assumed that the storage component can be charged from the grid after approximately 5 years without the risk of tax credit recapture.

solar profiles) was added to the model and then the storage component (assumed to be 4-hour duration) was modeled as either standalone or as a component of a solar hybrid facility. Two levels of storage MW were examined at either 50% or 100% of solar nameplate; for example, for 500 MW of solar, 250 and 500 MW of 4-hour storage were examined.

Table 8 shows the results.[49] For low levels of incremental solar hybrid generation, the percent reduction in storage ELCC (i.e., 8.3%) is noticeable. However, with incremental solar generation, net load becomes "peakier" and the reduction in storage ELCC caused by co-locating solar and storage is diminished.

Table 8 Percent Reduction in Storage ELCC for Solar Hybrid vs Standalone Storage

	Incremental Solar Nameplate (MW)			
Storage MW as % of Solar	**250**	**500**	**1000**	**2000**
50%	8.3%	4.3%	1.5%	1.1%
100%	8.3%	5.6%	3.4%	3.5%

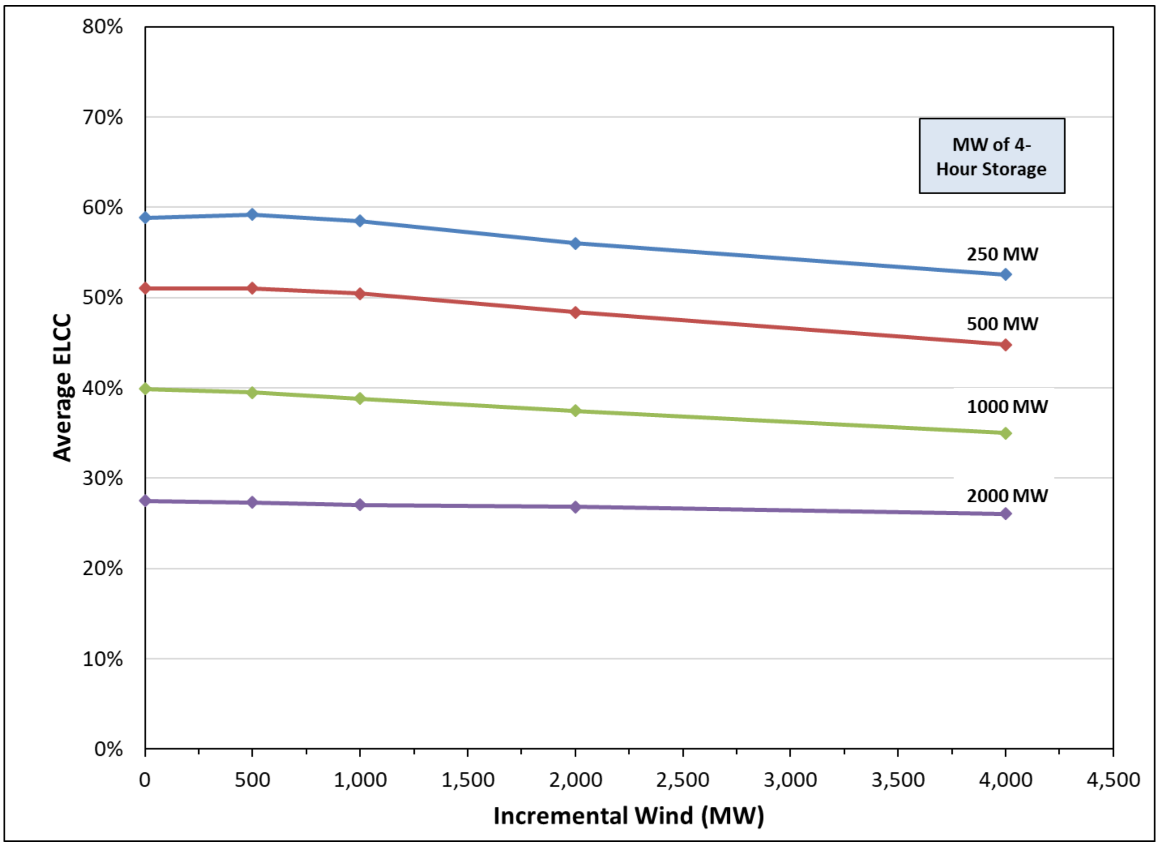
[49] Percent ELCC reductions are on storage MW only. A complete set of annual incremental and average ELCC results for those shown in Table 8 is included as Table A-11 in Appendix A.

Wind and Storage

To examine the interrelation between incremental storage and incremental wind generation, incremental levels of diversified wind were added to the model and then the ELCC of incremental levels of storage (250, 500, 1000, and 2000 MW) at that wind level were calculated. Average ELCC results are shown in Figure 12.[50]

A comparison of the results in Figure 12 with the results for solar in Figure 10 show that, at the levels of diversified wind studied, incremental wind does not cause a subsequent increase in the ELCC attributable to incremental storage. This is most likely a result of the inherently less "peakiness" of the hourly diversified wind profiles as compared to the hourly diversified solar profiles.[51]

Figure 12 Average ELCC for 4-Hour Duration Storage with Incremental Diversified Wind



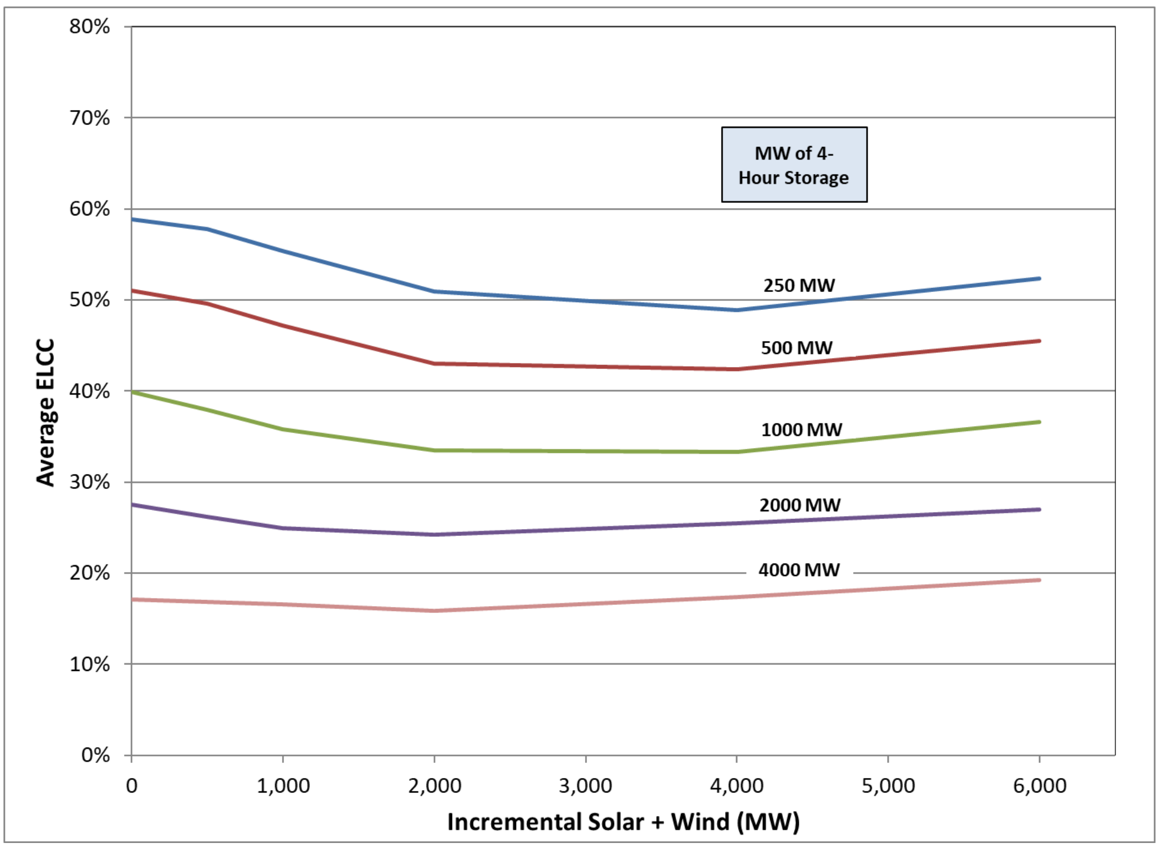
[50] The average ELCC values shown at 0 MW of wind are the same values as shown in Figure 8. A complete set of annual incremental and average ELCC results for those shown in Figure 12 is included in Table A-9 in Appendix A.

[51] Denholm, Nunemaker, Gagnon, and Cole, "The Potential for Battery Energy Storage to Provide Peaking Capacity in the United States", Page 10-14.

Solar, Wind, and Storage

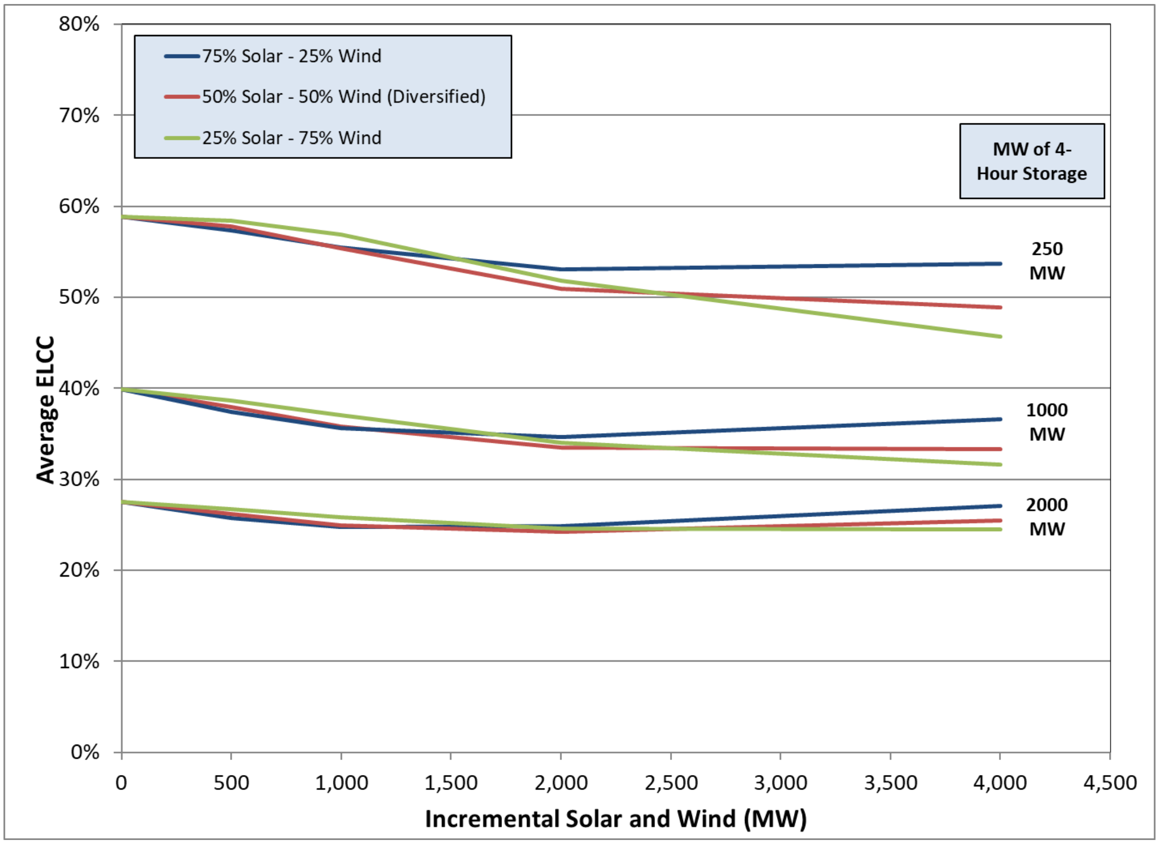
To examine the interrelation between incremental storage and incremental solar and wind generation together, incremental levels of diversified solar and wind combinations were added to the model and then the ELCC of incremental levels of storage at those levels was calculated. Average ELCC results for the case with incremental diversified solar and wind in a 50/50 MW combination and 4-hour duration storage are shown in Figure 13; average ELCC results for cases with other combinations of wind and solar are shown in Figure 14.[52]

Figure 13 Average ELCC for 4-Hour Duration Storage with Incremental Diversified Solar and Wind at a 50/50 Combination



[52] A complete set of annual incremental and average ELCC results for those shown in Figure 13 is included as Table A-11 in Appendix A; values for Figure 14 are shown in Table A-12.

Figure 14 Average ELCC for 4-Hour Duration Storage with Incremental Diversified Solar and Wind at Various Combinations



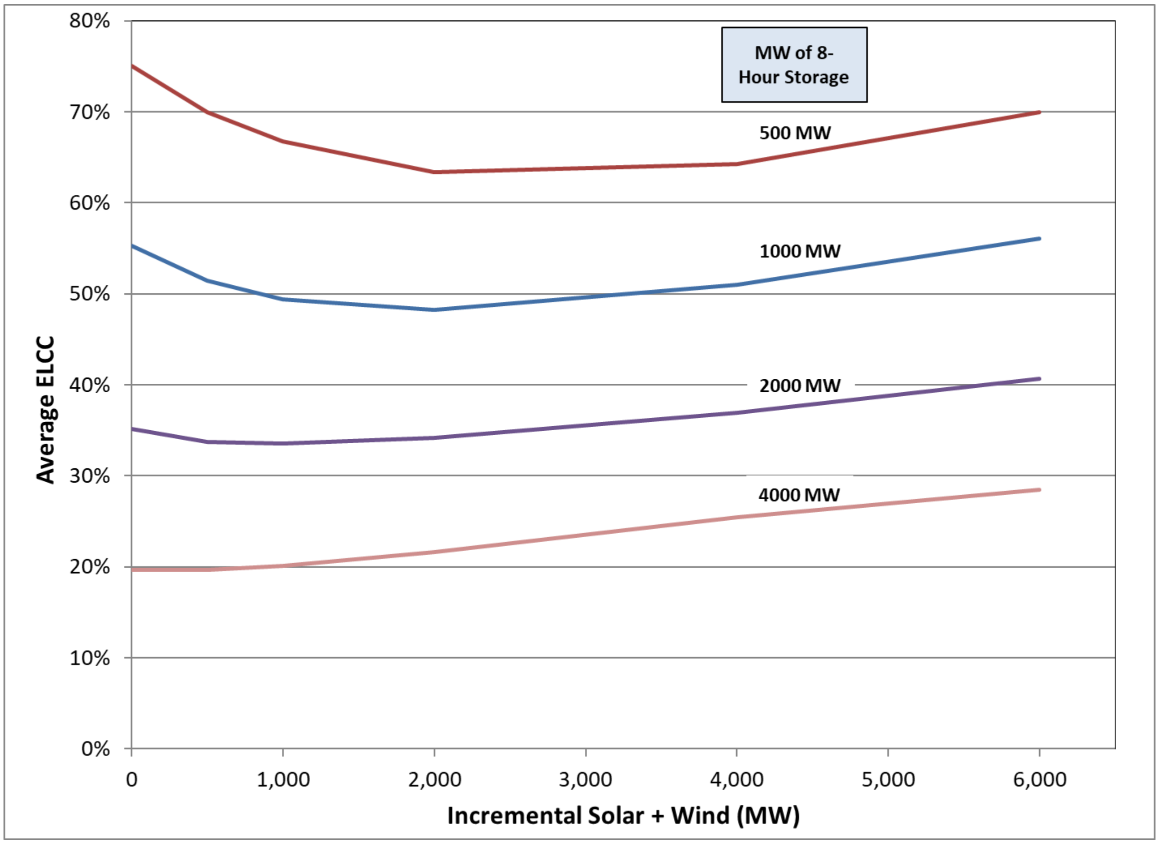
Average ELCC results for incremental 4-hour storage are consistent with prior analyses. That is, high penetrations of solar tend to increase the average ELCC attributable to incremental storage, while high penetrations of wind do not. This can be seen in Figure 14 by observing that at 4,000 MW of incremental solar and wind resources, the average ELCC values for storage are relatively in order; that is, the ELCC for storage is higher with increasing levels of solar (75%, 50%, and 25% solar).

Average ELCC results from examining 8-hour duration storage with 50/50 combinations of diversified solar and wind are shown in Figure 15.[53] As expected from standalone storage results shown earlier, 8-hour duration storage provides a higher level of average ELCC as opposed to 4-hour duration storage at each penetration level of storage evaluated. The 8-hour duration curves

[53] A complete set of annual incremental and average ELCC results for those shown in Figure 15 is included as Table A-13 in Appendix A

show the same initial decrease in average ELCC and then increase in portfolios with higher levels of solar and wind as seen with 4-hour storage.

Figure 15 Average ELCC for 8-Hour Duration Storage with Incremental Diversified Solar and Wind at a 50/50 Combination



Conclusions

This study report documents the results of an Effective Load Carrying Capability ("ELCC") study for: 1) the existing hydro, solar, wind, and storage resources in the Public Service Company of Colorado's portfolio and, 2) incremental solar, wind, and storage resources contemplated for inclusion in the portfolio. Existing ELCC results are used on the Company's loads and resources table to determine the need for any future resources to meet forecasted loads and planning reserve margin. Incremental ELCC results are used to determine the ability of those resources to meet any identified future resource needs. Based on the study results, the Company affords generation capacity credit to its existing resources consistent with the values shown in Table 6.

Study results show that the co-location of: 1) incremental solar and wind, and 2) incremental solar and storage when added to the Company's current portfolio should not be expected to experience significantly large reductions in ELCC when compared to similar levels of those same incremental resources that are not co-located; see Tables 7 and 8.

Study results also show that the ELCC values to be afforded large incremental amounts of 4-hour duration storage devices added to a portfolio are relatively insensitive to the amounts of incremental solar and wind also added to the portfolio; see Figures 10, 12, and 13.

ELCC values calculated for portfolios of incremental resources can differ from the sum of the standalone ELCCs for those same incremental resources. The level of difference depends upon such variables as: 1) the amount of these resource types already in the Company's existing portfolio, 2) the total MW of incremental resources, and 3) the relative proportions and locations of the various resource types assumed in the combination. However, at relatively moderate levels of incremental additions, an assumption of standalone ELCCs in summation as a proxy for a more accurate portfolio calculation of ELCC is sufficient to create potential portfolios. A final portfolio ELCC calculation should be conducted after portfolio creation/selection to ensure that firm capacity needs are met while at the same time not overbuilding the system from a firm capacity standpoint.

The Company's previous ELCC studies and capacity credit studies conducted elsewhere have clearly illustrated the law of diminishing returns as applied to non-dispatchable renewable generation; that is, marginal ELCCs are significantly lower than average ELCCs. This study report reaffirms that observation and extends it to the ELCC that can be attributed to incremental energy-limited resources such as storage. As shown here and in studies conducted elsewhere, energy-limited resources are not immune from the law of diminishing returns and incremental ELCC for those types of resources falls off rapidly with increasing penetrations at static levels of renewables.

Appendix A

Tables of Study Results

Table A-1 Annual Historical ELCC Results for 2021 Portfolio

2021 Portfolio - Standalone Results

Year	All Renewables	All Wind	Solar Technologies: All Solar	Utility Scale Solar	Community Gardens	All BTM	BTM Large	BTM Medium	BTM Small	Cabin Creek
2014	17.3%	11.5%	47.6%	49.5%	43.2%		37.9%	38.5%	36.2%	67.8%
2015	17.2%	10.0%	48.5%	64.1%	55.6%		30.6%	30.0%	28.7%	80.0%
2016	18.4%	12.4%	48.7%	56.0%	62.7%		40.3%	33.1%	31.8%	83.0%
2017	16.7%	8.4%	51.1%	72.1%	62.8%		30.6%	33.5%	32.6%	92.3%
2018	23.6%	17.3%	48.1%	65.5%	43.8%		29.0%	28.8%	27.4%	79.3%
2019	19.0%	12.0%	56.3%	72.1%	56.8%		41.1%	42.3%	40.4%	81.7%
Average	**18.7%**	**11.9%**	**50.1%**	**63.2%**	**54.1%**		**34.9%**	**34.4%**	**32.8%**	**80.7%**
Resource MW_AC	5,032	4,124	908	306	138		53	111	301	300
Capacity Credit (MW)	942	492	454	193	75		18	38	99	242

2021 Portfolio - Portfolio Effects Results

Year	All Renewables	All Wind	Solar Technologies: All Solar	Utility Scale Solar	Community Gardens	All BTM	BTM Large	BTM Medium	BTM Small	Cabin Creek
2014	17.3%	11.0%	45.8%	53.8%	47.0%	40.1%	41.2%	41.8%	39.3%	67.8%
2015	17.2%	10.2%	49.3%	70.2%	60.9%	32.0%	33.6%	32.9%	31.4%	80.0%
2016	18.4%	12.1%	47.5%	58.7%	65.7%	34.6%	42.3%	34.7%	33.3%	83.0%
2017	16.7%	8.8%	53.0%	75.7%	65.9%	34.2%	32.2%	35.1%	34.3%	92.3%
2018	23.6%	17.9%	49.6%	75.6%	50.6%	32.2%	33.5%	33.3%	31.6%	79.3%
2019	19.0%	11.4%	53.5%	71.6%	56.4%	40.7%	40.9%	42.0%	40.1%	81.7%
Average	**18.7%**	**11.9%**	**49.8%**	**67.6%**	**57.7%**	**35.7%**	**37.3%**	**36.6%**	**35.0%**	**80.7%**
Resource MW	5,032	4,124	908	306	138	464	53	111	301	300
Capacity Credit (MW)	942	490	452	207	80	165	20	40	105	242

Table A-2 Annual Historical ELCC Results for 2023 Portfolio

2023 Resource System - Standalone Results

			Solar Technologies								
Year	All Renewables	All Wind	All Solar	Utility Scale Solar	Community Gardens	All BTM	BTM Large	BTM Medium	BTM Small	Cabin Creek	Solar Hybrid Storage
2014	19.0%	11.5%	35.8%	28.8%	14.3%		11.7%	13.1%	15.0%	86.5%	51.7%
2015	20.4%	12.6%	40.4%	39.9%	32.4%		10.6%	9.0%	8.9%	92.0%	62.9%
2016	19.5%	13.8%	35.2%	28.2%	54.8%		28.3%	18.9%	16.7%	95.0%	65.6%
2017	23.9%	13.9%	52.4%	59.8%	52.8%		27.8%	26.0%	26.1%	89.5%	50.8%
2018	25.5%	18.8%	40.0%	40.4%	12.8%		7.2%	6.1%	6.0%	93.5%	69.6%
2019	23.2%	15.6%	47.6%	46.6%	38.3%		26.7%	26.9%	27.6%	94.0%	62.1%
Average	**21.9%**	**14.4%**	**41.9%**	**40.6%**	**34.2%**		**18.7%**	**16.7%**	**16.7%**	**91.8%**	**60.5%**
Resource MW_AC	6,192	4,124	2,068	1,281	196		77	133	383	300	275
Capacity Credit (MW)	1357	593	867	520	67		14	22	64	275	166

2023 Resource System - Portfolio Effects Results

			Solar Technologies								
Year	All Renewables	All Wind	All Solar	Utility Scale Solar	Community Gardens	All BTM	BTM Large	BTM Medium	BTM Small	Cabin Creek	Solar Hybrid Storage
2014	19.0%	11.1%	34.7%	43.0%	21.4%	21.1%	17.4%	19.6%	22.4%	86.5%	51.7%
2015	20.4%	11.8%	37.7%	49.4%	40.2%	11.3%	13.1%	11.1%	11.0%	92.0%	62.9%
2016	19.5%	12.8%	32.8%	33.0%	64.2%	21.9%	33.2%	22.2%	19.5%	95.0%	65.6%
2017	23.9%	12.4%	46.7%	56.3%	49.7%	24.8%	26.2%	24.4%	24.6%	89.5%	50.8%
2018	25.5%	18.5%	39.4%	56.9%	18.1%	8.7%	10.2%	8.6%	8.4%	93.5%	69.6%
2019	23.2%	13.7%	42.0%	48.5%	39.9%	28.5%	27.8%	28.1%	28.7%	94.0%	62.1%
Average	**21.9%**	**13.4%**	**38.9%**	**47.9%**	**38.9%**	**19.4%**	**21.3%**	**19.0%**	**19.1%**	**91.8%**	**60.5%**
Resource MW_AC	6,192	4,124	2,068	1,281	196	592	77	133	383	300	275
Capacity Credit (MW)	1356	553	804	614	76	115	16	25	73	275	166

Table A-3 Annual Incremental and Average Standalone Solar ELCC Results

(Inc Ave results apply to Incremental MW tranches; Tot Ave results apply to Total MW)

			Incremental to Existing Resources							Average of Total Incremental MW						
	Incremental MW	Total MW	2014	2015	2016	2017	2018	2019	Inc Ave	2014	2015	2016	2017	2018	2019	Tot Ave
MTN	100	100	12.7%	13.3%	20.9%	26.2%	8.5%	46.5%	**21.4%**	12.7%	13.3%	20.9%	26.2%	8.5%	46.5%	**21.4%**
	150	250	9.4%	12.4%	18.9%	23.3%	8.3%	37.9%	**18.4%**	10.7%	12.7%	19.7%	24.5%	8.4%	41.4%	**19.6%**
	250	500	5.5%	9.6%	16.6%	18.4%	7.6%	27.6%	**14.2%**	8.1%	11.2%	18.1%	21.4%	8.0%	34.5%	**16.9%**
	250	750	2.8%	7.6%	13.2%	14.0%	6.9%	19.2%	**10.6%**	6.3%	10.0%	16.5%	19.0%	7.7%	29.4%	**14.8%**
	250	1000	1.6%	6.1%	12.0%	12.1%	6.3%	14.0%	**8.7%**	5.1%	9.0%	15.4%	17.2%	7.3%	25.5%	**13.3%**
	500	1500	0.8%	4.5%	10.2%	9.7%	6.0%	10.7%	**7.0%**	3.7%	7.5%	13.6%	14.7%	6.9%	20.6%	**11.2%**
	500	2000	0.5%	3.0%	8.4%	6.6%	5.2%	7.6%	**5.2%**	2.9%	6.4%	12.3%	12.7%	6.5%	17.3%	**9.7%**
	500	2500	0.4%	2.1%	7.0%	5.2%	4.9%	6.2%	**4.3%**	2.4%	5.5%	11.3%	11.2%	6.1%	15.1%	**8.6%**
	500	3000	0.4%	1.6%	5.8%	3.9%	4.4%	5.2%	**3.6%**	2.0%	4.9%	10.4%	10.0%	5.9%	13.5%	**7.8%**
NFR	100	100	10.7%	17.9%	50.1%	54.7%	18.4%	49.5%	**33.5%**	10.7%	17.9%	50.1%	54.7%	18.4%	49.5%	**33.5%**
	150	250	8.5%	15.4%	48.0%	49.3%	17.1%	45.0%	**30.5%**	9.4%	16.4%	48.8%	51.5%	17.6%	46.8%	**31.7%**
	250	500	5.4%	11.2%	46.1%	41.0%	14.0%	39.5%	**26.2%**	7.4%	13.8%	47.5%	46.2%	15.8%	43.2%	**29.0%**
	250	750	3.4%	7.7%	40.9%	30.4%	12.2%	31.1%	**21.0%**	6.1%	11.8%	45.3%	40.9%	14.6%	39.1%	**26.3%**
	250	1000	2.1%	5.8%	35.8%	21.5%	10.4%	25.4%	**16.8%**	5.1%	10.3%	42.9%	36.1%	13.5%	35.7%	**23.9%**
	500	1500	1.2%	4.4%	26.0%	12.4%	9.5%	18.2%	**11.9%**	3.8%	8.3%	37.3%	28.2%	12.2%	29.9%	**19.9%**
	500	2000	0.7%	3.2%	14.5%	5.7%	7.5%	12.1%	**7.3%**	3.0%	7.0%	31.6%	22.6%	11.0%	25.4%	**16.8%**
	500	2500	0.5%	2.6%	7.5%	2.8%	6.1%	9.0%	**4.7%**	2.5%	6.1%	26.8%	18.6%	10.0%	22.1%	**14.4%**
	500	3000	0.4%	2.2%	3.6%	1.6%	5.2%	6.1%	**3.2%**	2.1%	5.5%	22.9%	15.8%	9.2%	19.5%	**12.5%**
SFR	100	100	9.5%	13.7%	9.4%	32.9%	14.0%	13.0%	**15.4%**	9.5%	13.7%	9.4%	32.9%	14.0%	13.0%	**15.4%**
	150	250	8.2%	12.1%	10.0%	28.2%	12.6%	11.9%	**13.9%**	8.7%	12.8%	9.8%	30.1%	13.2%	12.3%	**14.5%**
	250	500	5.9%	9.8%	8.9%	20.9%	10.9%	10.0%	**11.1%**	7.3%	11.3%	9.4%	25.5%	12.1%	11.2%	**12.8%**
	250	750	4.1%	7.8%	8.0%	16.7%	9.0%	8.3%	**9.0%**	6.3%	10.1%	8.9%	22.6%	11.0%	10.2%	**11.5%**
	250	1000	2.6%	6.1%	7.5%	14.0%	7.8%	7.6%	**7.6%**	5.3%	9.1%	8.6%	20.4%	10.2%	9.5%	**10.5%**
	500	1500	1.4%	4.9%	7.0%	11.0%	7.0%	6.4%	**6.3%**	4.0%	7.7%	8.1%	17.3%	9.2%	8.5%	**9.1%**
	500	2000	0.6%	3.3%	6.0%	9.5%	6.2%	5.4%	**5.2%**	3.2%	6.6%	7.5%	15.3%	8.4%	7.7%	**8.1%**
	500	2500	0.3%	2.7%	5.4%	8.1%	5.2%	4.7%	**4.4%**	2.6%	5.8%	7.1%	13.9%	7.8%	7.1%	**7.4%**
	500	3000	0.0%	2.1%	5.1%	6.3%	4.5%	4.0%	**3.7%**	2.2%	5.2%	6.8%	12.6%	7.2%	6.6%	**6.8%**

Table A-3 (continued) Annual Incremental and Average Standalone Solar ELCC Results

(Inc Ave results apply to Incremental MW tranches; Tot Ave results apply to Total MW)

			Incremental to Existing Resources							Average of Total Incremental MW						
	Incremental MW	Total MW	2014	2015	2016	2017	2018	2019	Inc Ave	2014	2015	2016	2017	2018	2019	Tot Ave
SLV	100	100	9.6%	16.6%	48.4%	61.6%	11.1%	22.9%	**28.4%**	9.6%	16.6%	48.4%	61.6%	11.1%	22.9%	**28.4%**
SLV	150	250	7.4%	13.9%	40.0%	54.8%	10.5%	21.5%	**24.7%**	8.3%	15.0%	43.4%	57.5%	10.7%	22.1%	**26.2%**
SLV	250	500	4.7%	9.3%	28.0%	42.8%	8.8%	19.4%	**18.8%**	6.5%	12.1%	35.7%	50.1%	9.8%	20.8%	**22.5%**
SLV	250	750	2.8%	6.1%	19.3%	28.9%	7.7%	17.0%	**13.6%**	5.2%	10.1%	30.2%	43.1%	9.1%	19.5%	**19.5%**
SLV	250	1000	1.6%	4.4%	12.4%	18.9%	6.9%	15.9%	**10.0%**	4.3%	8.7%	25.8%	37.0%	8.5%	18.6%	**17.2%**
SLV	500	1500	0.9%	3.1%	10.0%	9.6%	6.6%	14.3%	**7.4%**	3.2%	6.8%	20.5%	27.9%	7.9%	17.2%	**13.9%**
SLV	500	2000	0.6%	2.4%	7.5%	4.2%	5.5%	13.1%	**5.5%**	2.6%	5.7%	17.3%	22.0%	7.3%	16.2%	**11.8%**
SLV	500	2500	0.4%	1.9%	6.1%	2.4%	5.1%	12.1%	**4.7%**	2.1%	5.0%	15.0%	18.0%	6.9%	15.3%	**10.4%**
SLV	500	3000	0.3%	1.5%	5.4%	1.5%	4.9%	10.7%	**4.1%**	1.8%	4.4%	13.4%	15.3%	6.5%	14.6%	**9.3%**
WS	100	100	20.2%	35.0%	43.2%	44.6%	23.3%	51.5%	**36.3%**	20.2%	35.0%	43.2%	44.6%	23.3%	51.5%	**36.3%**
WS	150	250	13.3%	27.6%	35.2%	38.9%	23.3%	44.5%	**30.5%**	16.1%	30.5%	38.4%	41.2%	23.3%	47.3%	**32.8%**
WS	250	500	6.4%	19.4%	26.9%	34.3%	19.3%	40.5%	**24.5%**	11.2%	25.0%	32.7%	37.7%	21.3%	43.9%	**28.6%**
WS	250	750	2.3%	12.0%	19.7%	29.2%	16.6%	33.4%	**18.9%**	8.3%	20.6%	28.3%	34.9%	19.7%	40.4%	**25.4%**
WS	250	1000	1.0%	7.1%	12.9%	23.4%	13.1%	28.6%	**14.4%**	6.4%	17.2%	24.5%	32.0%	18.1%	37.5%	**22.6%**
WS	500	1500	0.4%	3.3%	10.0%	15.4%	10.5%	20.6%	**10.0%**	4.4%	12.6%	19.7%	26.5%	15.5%	31.8%	**18.4%**
WS	500	2000	0.0%	1.5%	7.0%	8.2%	7.6%	12.7%	**6.2%**	3.3%	9.8%	16.5%	21.9%	13.6%	27.0%	**15.4%**
WS	500	2500	0.0%	0.8%	6.3%	3.7%	5.6%	7.8%	**4.0%**	2.7%	8.0%	14.5%	18.3%	12.0%	23.2%	**13.1%**
WS	500	3000	0.0%	0.6%	5.5%	2.0%	4.4%	4.7%	**2.9%**	2.2%	6.8%	13.0%	15.6%	10.7%	20.1%	**11.4%**
SE	100	100	8.0%	21.6%	40.3%	55.5%	18.7%	31.6%	**29.3%**	8.0%	21.6%	40.3%	55.5%	18.7%	31.6%	**29.3%**
SE	150	250	6.3%	19.0%	34.9%	47.9%	19.3%	29.4%	**26.1%**	6.9%	20.1%	37.1%	51.0%	19.0%	30.3%	**27.4%**
SE	250	500	4.2%	14.0%	29.2%	37.9%	17.4%	24.3%	**21.2%**	5.6%	17.0%	33.1%	44.4%	18.2%	27.3%	**24.3%**
SE	250	750	3.1%	10.1%	24.1%	25.3%	14.0%	21.3%	**16.3%**	4.8%	14.7%	30.1%	38.1%	16.8%	25.3%	**21.6%**
SE	250	1000	2.2%	7.3%	18.8%	17.5%	14.0%	17.2%	**12.9%**	4.1%	12.9%	27.3%	32.9%	16.1%	23.3%	**19.4%**
SE	500	1500	1.3%	4.8%	13.6%	10.6%	10.7%	14.1%	**9.2%**	3.2%	10.2%	22.7%	25.5%	14.3%	20.2%	**16.0%**
SE	500	2000	0.9%	2.9%	9.9%	7.0%	8.7%	11.2%	**6.8%**	2.6%	8.4%	19.5%	20.9%	12.9%	18.0%	**13.7%**
SE	500	2500	0.5%	1.8%	7.9%	4.2%	6.1%	8.8%	**4.9%**	2.2%	7.0%	17.2%	17.5%	11.5%	16.1%	**11.9%**
SE	500	3000	0.4%	1.1%	6.3%	3.0%	4.4%	7.0%	**3.7%**	1.9%	6.1%	15.4%	15.1%	10.4%	14.6%	**10.6%**

Table A-3 (continued) Annual Incremental and Average Standalone Solar ELCC Results

(Inc Ave results apply to Incremental MW tranches; Tot Ave results apply to Total MW)

			Incremental to Existing Resources							Average of Total Incremental MW						
	Incremental MW	Total MW	2014	2015	2016	2017	2018	2019	Inc Ave	2014	2015	2016	2017	2018	2019	Tot Ave
BTM	100	100	9.9%	8.2%	19.3%	26.5%	0.0%	24.4%	**14.7%**	9.9%	8.2%	19.3%	26.5%	0.0%	24.4%	**14.7%**
	150	250	7.9%	7.9%	19.3%	26.1%	1.5%	23.3%	**14.3%**	8.7%	8.0%	19.3%	26.3%	0.9%	23.8%	**14.5%**
	250	500	4.9%	6.8%	19.2%	23.1%	0.8%	22.0%	**12.8%**	6.8%	7.4%	19.2%	24.7%	0.9%	22.9%	**13.7%**
	250	750	2.9%	5.8%	17.3%	21.2%	0.9%	18.9%	**11.2%**	5.5%	6.9%	18.6%	23.5%	0.9%	21.6%	**12.8%**
	250	1000	1.6%	5.1%	16.6%	17.5%	0.7%	16.7%	**9.7%**	4.5%	6.5%	18.1%	22.0%	0.9%	20.3%	**12.0%**
	500	1500	0.8%	4.2%	15.2%	14.2%	0.6%	12.9%	**8.0%**	3.3%	5.7%	17.1%	19.4%	0.8%	17.8%	**10.7%**
	500	2000	0.5%	3.3%	14.2%	10.9%	0.5%	9.9%	**6.6%**	2.6%	5.1%	16.4%	17.3%	0.7%	15.9%	**9.7%**
CSG	100	100	10.3%	25.9%	32.2%	57.8%	10.1%	35.0%	**28.5%**	10.3%	25.9%	32.2%	57.8%	10.1%	35.0%	**28.5%**
	150	250	8.4%	23.3%	31.5%	54.2%	9.9%	32.2%	**26.6%**	9.1%	24.4%	31.8%	55.6%	10.0%	33.3%	**27.4%**
	250	500	5.6%	19.8%	29.3%	49.9%	9.0%	28.5%	**23.7%**	7.4%	22.1%	30.6%	52.8%	9.5%	30.9%	**25.5%**
	250	750	3.6%	15.0%	28.1%	39.4%	7.8%	25.4%	**19.9%**	6.1%	19.7%	29.7%	48.3%	8.9%	29.1%	**23.6%**
	250	1000	2.3%	11.3%	26.0%	28.8%	7.0%	22.2%	**16.2%**	5.1%	17.6%	28.8%	43.4%	8.5%	27.4%	**21.8%**
	500	1500	1.1%	8.3%	23.2%	15.3%	6.5%	17.6%	**12.0%**	3.8%	14.5%	26.9%	34.1%	7.8%	24.1%	**18.5%**
	500	2000	0.7%	5.1%	19.2%	6.1%	5.6%	13.3%	**8.3%**	3.0%	12.2%	25.0%	27.1%	7.2%	21.4%	**16.0%**

Table A-4 Annual Incremental and Average Combination Standalone Solar ELCC Results

(Inc Ave results apply to Incremental MW tranches; Tot Ave results apply to Total MW)

			Incremental to 2023 Existing Resources							Average of Total Incremental MW						
	Incremental MW	Total MW	2014	2015	2016	2017	2018	2019	Inc Ave	2014	2015	2016	2017	2018	2019	Tot Ave
50/50 MTN/NFR	100	100	11.8%	15.8%	35.0%	41.7%	13.3%	49.2%	**27.8%**	11.8%	15.8%	35.0%	41.7%	13.3%	49.2%	**27.8%**
	150	250	9.0%	14.2%	35.5%	36.9%	12.9%	42.1%	**25.1%**	10.1%	14.9%	35.3%	38.8%	13.1%	44.9%	**26.2%**
	250	500	5.7%	11.3%	32.2%	31.4%	11.6%	35.2%	**21.2%**	7.9%	13.1%	33.8%	35.1%	12.3%	40.0%	**23.7%**
	500	1000	2.4%	7.8%	28.3%	23.5%	9.5%	23.8%	**15.9%**	5.1%	10.5%	31.0%	29.3%	10.9%	31.9%	**19.8%**
	1000	2000	0.8%	4.2%	20.5%	12.2%	7.1%	13.2%	**9.7%**	3.0%	7.4%	25.8%	20.8%	9.0%	22.6%	**14.7%**
	1000	3000	0.4%	2.3%	10.6%	4.3%	5.7%	8.0%	**5.2%**	2.1%	5.7%	20.7%	15.3%	7.9%	17.7%	**11.6%**
50/50 MTN/SFR	100	100	11.2%	13.4%	15.5%	29.7%	11.4%	30.3%	**18.6%**	11.2%	13.4%	15.5%	29.7%	11.4%	30.3%	**18.6%**
	150	250	9.0%	12.5%	14.9%	26.2%	10.8%	28.4%	**17.0%**	9.9%	12.9%	15.2%	27.6%	11.0%	29.1%	**17.6%**
	250	500	6.1%	10.3%	14.0%	20.7%	9.5%	23.4%	**14.0%**	8.0%	11.6%	14.6%	24.2%	10.3%	26.3%	**15.8%**
	500	1000	2.8%	7.5%	10.9%	15.1%	8.2%	17.9%	**10.4%**	5.4%	9.6%	12.7%	19.7%	9.2%	22.1%	**13.1%**
	1000	2000	0.8%	4.3%	8.7%	10.3%	6.3%	11.7%	**7.0%**	3.1%	7.0%	10.7%	15.0%	7.7%	16.9%	**10.1%**
	1000	3000	0.3%	2.2%	6.8%	6.8%	5.1%	7.9%	**4.8%**	2.2%	5.4%	9.4%	12.2%	6.9%	13.9%	**8.3%**
50/50 NFR/SFR	100	100	10.2%	16.0%	29.7%	44.9%	16.1%	31.8%	**24.8%**	10.2%	16.0%	29.7%	44.9%	16.1%	31.8%	**24.8%**
	150	250	8.4%	14.0%	30.6%	38.9%	15.0%	31.6%	**23.1%**	9.1%	14.8%	30.2%	41.3%	15.4%	31.7%	**23.7%**
	250	500	5.9%	10.8%	27.8%	32.7%	13.1%	26.6%	**19.5%**	7.5%	12.8%	29.0%	37.0%	14.2%	29.1%	**21.6%**
	500	1000	3.1%	7.0%	26.2%	23.1%	10.7%	23.7%	**15.6%**	5.3%	9.9%	27.6%	30.0%	12.5%	26.4%	**18.6%**
	1000	2000	1.0%	4.1%	21.1%	12.1%	7.8%	17.1%	**10.5%**	3.1%	7.0%	24.3%	21.1%	10.1%	21.7%	**14.6%**
	1000	3000	0.4%	2.2%	12.6%	4.6%	6.0%	10.3%	**6.0%**	2.2%	5.4%	20.4%	15.6%	8.7%	17.9%	**11.7%**
Diversified	100	100	12.0%	19.6%	37.1%	46.6%	15.9%	37.0%	**28.0%**	12.0%	19.6%	37.1%	46.6%	15.9%	37.0%	**28.0%**
	150	250	9.5%	17.7%	33.9%	43.0%	15.2%	34.6%	**25.6%**	10.5%	18.5%	35.1%	44.4%	15.5%	35.5%	**26.6%**
	250	500	6.2%	14.0%	31.0%	37.6%	14.0%	32.0%	**22.5%**	8.4%	16.2%	33.1%	41.0%	14.7%	33.8%	**24.5%**
	500	1000	2.8%	9.2%	26.3%	27.0%	11.4%	28.7%	**17.6%**	5.6%	12.7%	29.7%	34.0%	13.0%	31.2%	**21.1%**
	1000	2000	0.8%	4.6%	17.9%	11.5%	8.8%	20.3%	**10.7%**	3.2%	8.7%	23.8%	22.8%	10.9%	25.8%	**15.9%**
	1000	3000	0.3%	2.0%	10.4%	2.8%	6.0%	10.6%	**5.4%**	2.2%	6.5%	19.3%	16.1%	9.3%	20.7%	**12.4%**

Table A-5 Annual Incremental and Average Standalone Wind ELCC Results

(Inc Ave results apply to Incremental MW tranches; Tot Ave results apply to Total MW)

			Incremental to 2023 Existing Resources							Average of Total Incremental MW						
	Incremental MW	Total MW	2014	2015	2016	2017	2018	2019	Inc Ave	2014	2015	2016	2017	2018	2019	Tot Ave
ERZ-1	250	250	9.5%	5.9%	21.0%	12.9%	35.2%	11.1%	**15.9%**	9.5%	5.9%	21.0%	12.9%	35.2%	11.1%	**15.9%**
	250	500	6.9%	5.1%	17.9%	11.8%	29.8%	7.1%	**13.1%**	8.2%	5.5%	19.5%	12.4%	32.5%	9.1%	**14.5%**
	500	1000	5.0%	4.0%	13.3%	10.7%	23.5%	3.7%	**10.0%**	6.6%	4.8%	16.4%	11.5%	28.0%	6.4%	**12.3%**
	1000	2000	3.0%	3.0%	9.3%	9.1%	15.4%	1.6%	**6.9%**	4.8%	3.9%	12.9%	10.3%	21.7%	4.0%	**9.6%**
	1000	3000	1.7%	2.4%	7.5%	7.2%	10.1%	0.8%	**5.0%**	3.8%	3.4%	11.1%	9.3%	17.8%	2.9%	**8.1%**
ERZ-2	250	250	7.8%	5.4%	14.0%	14.0%	16.9%	18.7%	**12.8%**	7.8%	5.4%	14.0%	14.0%	16.9%	18.7%	**12.8%**
	250	500	7.5%	4.9%	11.3%	10.7%	16.0%	17.8%	**11.4%**	7.6%	5.2%	12.7%	12.3%	16.4%	18.3%	**12.1%**
	500	1000	7.0%	4.1%	10.4%	9.3%	15.3%	15.8%	**10.3%**	7.3%	4.6%	11.5%	10.8%	15.9%	17.0%	**11.2%**
	1000	2000	5.3%	3.2%	7.5%	6.5%	14.9%	14.0%	**8.6%**	6.31%	3.9%	9.5%	8.7%	15.4%	15.5%	**9.9%**
	1000	3000	4.1%	2.1%	5.5%	5.1%	13.9%	11.8%	**7.1%**	5.6%	3.3%	8.2%	7.5%	14.9%	14.2%	**9.0%**
ERZ-3	250	250	23.7%	28.4%	46.2%	10.7%	43.7%	49.1%	**33.6%**	23.7%	28.4%	46.2%	10.7%	43.7%	49.1%	**33.6%**
	250	500	18.3%	19.3%	41.2%	8.5%	40.3%	44.1%	**28.6%**	21.0%	23.9%	43.7%	9.6%	42.0%	46.6%	**31.1%**
	500	1000	13.2%	10.0%	34.3%	7.0%	34.4%	36.6%	**22.6%**	17.1%	16.9%	39.0%	8.3%	38.2%	41.6%	**26.9%**
	1000	2000	8.2%	3.5%	21.4%	4.2%	21.4%	21.7%	**13.4%**	12.7%	10.2%	30.2%	6.2%	29.8%	31.7%	**20.1%**
	1000	3000	5.0%	1.5%	8.4%	2.6%	9.9%	8.8%	**6.1%**	10.1%	7.3%	22.9%	5.0%	23.2%	24.0%	**15.4%**
ERZ-5	250	250				18.7%	36.4%	17.5%	**24.2%**				18.7%	36.4%	17.5%	**24.2%**
	250	500				14.0%	32.7%	16.3%	**21.0%**				16.4%	34.6%	16.9%	**22.6%**
	500	1000				11.4%	28.3%	13.5%	**17.7%**				13.9%	31.4%	15.2%	**20.2%**
	1000	2000				8.3%	19.0%	11.3%	**12.9%**				11.1%	25.2%	13.3%	**16.5%**
	1000	3000				7.4%	11.7%	9.5%	**9.5%**				9.9%	20.7%	12.0%	**14.2%**
ERZ-5 44% NCF	250	250				14.0%	27.3%	11.6%	**17.6%**				14.0%	27.3%	11.6%	**17.6%**
	250	500				11.6%	25.1%	10.8%	**15.8%**				12.8%	26.2%	11.2%	**16.7%**
	500	1000				8.9%	21.2%	10.1%	**13.4%**				10.9%	23.7%	10.6%	**15.1%**
	1000	2000				6.1%	15.3%	8.2%	**9.8%**				8.5%	19.5%	9.4%	**12.5%**
	1000	3000				5.1%	10.2%	7.1%	**7.5%**				7.3%	16.4%	8.6%	**10.8%**

Table A-6 Annual Incremental and Average Combination Standalone Wind ELCC Results

(Inc Ave results apply to Incremental MW tranches; Tot Ave results apply to Total MW)

			Incremental to 2023 Existing Resources							Average of Total Incremental MW						
	Incremental MW	Total MW	2014	2015	2016	2017	2018	2019	Inc Ave	2014	2015	2016	2017	2018	2019	Tot Ave
50/50 ERZ1/ERZ2	500	500	9.3%	5.7%	16.4%	13.2%	25.8%	14.8%	**14.2%**	9.3%	5.7%	16.4%	13.2%	25.8%	14.8%	**14.2%**
	500	1000	7.6%	4.7%	13.0%	12.1%	23.7%	12.2%	**12.2%**	8.5%	5.2%	14.7%	12.7%	24.7%	13.5%	**13.2%**
	1000	2000	6.7%	3.9%	8.9%	10.8%	19.3%	9.6%	**9.9%**	7.6%	4.6%	11.8%	11.7%	22.0%	11.6%	**11.5%**
	1000	3000	6.1%	3.2%	6.7%	9.6%	14.3%	8.0%	**8.0%**	7.1%	4.1%	10.1%	11.0%	19.5%	10.4%	**10.4%**
50/50 ERZ1/ERZ3	500	500	16.0%	17.1%	32.6%	11.7%	38.2%	29.8%	**24.2%**	16.0%	17.1%	32.6%	11.7%	38.2%	29.8%	**24.2%**
	500	1000	11.8%	11.1%	27.0%	10.2%	30.7%	25.2%	**19.3%**	13.9%	14.1%	29.8%	10.9%	34.4%	27.5%	**21.8%**
	1000	2000	9.3%	5.9%	20.7%	8.8%	21.1%	19.9%	**14.3%**	11.6%	10.0%	25.3%	9.9%	27.8%	23.7%	**18.0%**
	1000	3000	7.6%	3.1%	15.4%	7.6%	12.9%	15.0%	**10.3%**	10.2%	7.7%	22.0%	9.1%	22.8%	20.8%	**15.4%**
50/50 ERZ2/ERZ3	500	500	15.4%	16.9%	29.2%	11.7%	30.0%	33.6%	**22.8%**	15.4%	16.9%	29.2%	11.7%	30.0%	33.6%	**22.8%**
	500	1000	12.1%	11.3%	25.1%	9.3%	28.1%	29.9%	**19.3%**	13.7%	14.1%	27.1%	10.5%	29.0%	31.7%	**21.0%**
	1000	2000	8.3%	6.2%	19.8%	6.9%	24.0%	25.6%	**15.1%**	11.0%	10.1%	23.5%	8.7%	26.5%	28.6%	**18.1%**
	1000	3000	5.4%	3.5%	14.6%	5.3%	18.0%	20.8%	**11.3%**	9.2%	7.9%	20.5%	7.6%	23.7%	26.0%	**15.8%**
Diversifed	500	500	13.9%	13.7%	26.3%	12.4%	31.8%	27.0%	**20.8%**	13.9%	13.7%	26.3%	12.4%	31.8%	27.0%	**20.8%**
	500	1000	11.4%	10.5%	22.3%	11.2%	28.5%	23.5%	**17.9%**	12.6%	12.1%	24.3%	11.8%	30.1%	25.2%	**19.4%**
	1000	2000	9.0%	6.8%	17.7%	9.9%	22.8%	20.6%	**14.5%**	10.8%	9.4%	21.0%	10.9%	26.5%	22.9%	**16.9%**
	1000	3000	7.2%	4.2%	14.0%	8.9%	16.1%	17.4%	**11.3%**	9.6%	7.7%	18.7%	10.2%	23.0%	21.1%	**15.1%**

Table A-7 Annual Incremental and Average Standalone Storage ELCC Results

(Inc Ave results apply to Incremental MW tranches; Tot Ave results apply to Total MW)

			Incremental to 2023 Existing Resources							Average of Total Incremental MW						
	Incremental MW	**Total MW**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Inc Ave**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Tot Ave**
2-Hour Duration	50	50	30.7%	42.7%	65.5%	51.4%	43.8%	58.8%	**48.8%**	30.7%	42.7%	65.5%	51.4%	43.8%	58.8%	**48.8%**
	50	100	28.9%	36.2%	57.7%	44.1%	39.3%	51.6%	**43.0%**	29.8%	39.5%	61.6%	47.8%	41.5%	55.2%	**45.9%**
	150	250	24.7%	28.0%	48.7%	36.0%	32.5%	43.9%	**35.6%**	26.7%	32.6%	53.9%	40.7%	36.1%	48.4%	**39.7%**
	250	500	20.5%	21.0%	34.1%	23.7%	24.8%	31.2%	**25.9%**	23.6%	26.8%	44.0%	32.2%	30.5%	39.8%	**32.8%**
	250	750	18.2%	17.1%	24.6%	18.2%	22.9%	22.3%	**20.5%**	21.8%	23.6%	37.5%	27.6%	27.9%	34.0%	**28.7%**
	250	1000	16.8%	14.5%	21.0%	16.0%	21.7%	19.5%	**18.2%**	20.5%	21.3%	33.4%	24.7%	26.4%	30.3%	**26.1%**
	500	1500	15.3%	11.3%	17.9%	13.6%	19.6%	16.0%	**15.6%**	18.8%	18.0%	28.2%	21.0%	24.1%	25.5%	**22.6%**
	500	2000	13.5%	7.5%	14.3%	10.1%	16.6%	11.7%	**12.3%**	17.5%	15.3%	24.7%	18.3%	22.2%	22.1%	**20.0%**
	500	2500	12.9%	5.4%	10.7%	8.3%	13.0%	8.6%	**9.8%**	16.6%	13.3%	21.9%	16.3%	20.4%	19.4%	**18.0%**
	500	3000	12.0%	3.9%	8.1%	7.2%	9.4%	6.6%	**7.9%**	15.8%	11.8%	19.6%	14.7%	18.6%	17.3%	**16.3%**
4-Hour Duration	50	50	54.3%	62.3%	81.6%	70.0%	64.1%	76.3%	**68.1%**	54.3%	62.3%	81.6%	70.0%	64.1%	76.3%	**68.1%**
	50	100	50.2%	55.5%	73.8%	61.1%	60.6%	70.0%	**61.9%**	52.3%	58.9%	77.7%	65.6%	62.4%	73.2%	**65.0%**
	150	250	43.1%	46.4%	67.4%	53.8%	55.6%	61.9%	**54.7%**	46.8%	51.4%	71.5%	58.5%	58.3%	66.4%	**58.8%**
	250	500	35.3%	33.3%	54.9%	39.1%	46.9%	49.6%	**43.2%**	41.0%	42.3%	63.2%	48.8%	52.6%	58.0%	**51.0%**
	250	750	30.6%	22.8%	40.2%	27.9%	39.5%	36.9%	**33.0%**	37.6%	35.8%	55.5%	41.8%	48.2%	51.0%	**45.0%**
	250	1000	27.1%	15.0%	28.7%	20.4%	33.2%	23.3%	**24.6%**	34.9%	30.6%	48.8%	36.5%	44.5%	44.1%	**39.9%**
	500	1500	25.0%	9.5%	18.8%	15.4%	22.5%	15.7%	**17.8%**	31.6%	23.6%	38.8%	29.5%	37.1%	34.6%	**32.5%**
	500	2000	21.1%	5.8%	12.5%	11.8%	12.6%	10.2%	**12.3%**	29.0%	19.1%	32.2%	25.0%	31.0%	28.5%	**27.5%**
	500	2500	16.8%	4.4%	9.4%	9.3%	10.2%	7.7%	**9.6%**	26.6%	16.2%	27.7%	21.9%	26.8%	24.3%	**23.9%**
	500	3000	12.6%	3.4%	8.0%	7.5%	9.2%	6.9%	**7.9%**	24.2%	14.1%	24.4%	19.5%	23.9%	21.4%	**21.3%**
8-Hour Duration	50	50	88.4%	88.3%	97.6%	88.4%	96.1%	94.9%	**92.3%**	88.4%	88.3%	97.6%	88.4%	96.1%	94.9%	**92.3%**
	50	100	80.5%	83.5%	95.0%	85.7%	94.6%	92.0%	**88.6%**	84.5%	85.9%	96.3%	87.0%	95.3%	93.5%	**90.4%**
	150	250	74.1%	69.4%	92.5%	76.6%	91.2%	86.7%	**81.7%**	78.3%	76.0%	94.1%	80.8%	92.8%	89.4%	**85.2%**
	250	500	61.8%	44.4%	78.1%	58.6%	78.3%	68.3%	**64.9%**	70.0%	60.2%	86.1%	69.7%	85.6%	78.9%	**75.1%**
	250	750	50.5%	20.8%	53.6%	37.1%	50.2%	46.9%	**43.2%**	63.5%	47.1%	75.3%	58.8%	73.8%	68.2%	**64.4%**
	250	1000	42.5%	12.8%	32.9%	25.5%	27.4%	25.8%	**27.8%**	58.3%	38.5%	64.7%	50.5%	62.2%	57.6%	**55.3%**
	500	1500	29.6%	8.9%	18.2%	17.0%	20.1%	15.7%	**18.2%**	48.7%	28.6%	49.2%	39.3%	48.1%	43.6%	**42.9%**
	500	2000	14.3%	6.5%	12.9%	11.3%	14.8%	11.1%	**11.8%**	40.1%	23.1%	40.1%	32.3%	39.8%	35.5%	**35.2%**
	500	2500	6.2%	5.7%	10.0%	7.9%	9.4%	7.7%	**7.8%**	33.4%	19.6%	34.1%	27.4%	33.7%	29.9%	**29.7%**
	500	3000	3.6%	5.0%	8.0%	4.9%	5.6%	6.1%	**5.5%**	28.4%	17.2%	29.7%	23.7%	29.0%	26.0%	**25.7%**

Table A-8 Annual Incremental and Average Solar/Wind Combinations ELCC Results

(Inc Ave results apply to Incremental MW tranches; Tot Ave results apply to Total MW)

				Incremental to 2023 Existing Resources							Average of Total Incremental MW						
		Incremental MW	Total MW	2014	2015	2016	2017	2018	2019	Inc Ave	2014	2015	2016	2017	2018	2019	Tot Ave
25% Solar 75% Wind	Portfolio	500	500	13.6%	15.4%	30.1%	21.3%	28.8%	29.8%	**23.2%**	13.6%	15.4%	30.1%	21.3%	28.8%	29.8%	**23.2%**
		500	1000	11.4%	12.9%	28.9%	20.4%	27.0%	28.5%	**21.5%**	12.5%	14.2%	29.5%	20.8%	27.9%	29.1%	**22.3%**
		1000	2000	9.1%	9.0%	26.3%	18.6%	24.2%	26.6%	**19.0%**	10.8%	11.6%	27.9%	19.7%	26.0%	27.9%	**20.6%**
		2000	4000	6.9%	5.1%	19.8%	14.5%	16.8%	22.9%	**14.3%**	8.9%	8.3%	23.8%	17.1%	21.4%	25.4%	**17.5%**
		2000	6000	5.3%	3.5%	9.8%	8.6%	9.3%	16.1%	**8.8%**	7.7%	6.7%	19.1%	14.3%	17.3%	22.3%	**14.6%**
	Standalone	500	500														
		500	1000	12.5%	14.3%	28.0%	19.6%	27.5%	28.7%	**21.8%**	12.5%	14.3%	28.0%	19.6%	27.5%	28.7%	**21.8%**
		1000	2000	9.2%	10.2%	23.3%	15.1%	24.2%	24.8%	**17.8%**	10.9%	12.3%	25.7%	17.4%	25.9%	26.7%	**19.8%**
		2000	4000	7.0%	6.2%	17.7%	10.3%	19.3%	20.5%	**13.5%**	8.9%	9.2%	21.7%	13.8%	22.6%	23.6%	**16.7%**
		2000	6000	5.5%	3.7%	13.1%	7.4%	13.6%	15.7%	**9.8%**	7.8%	7.4%	18.8%	11.7%	19.6%	21.0%	**14.4%**
50% Solar 50% Wind	Portfolio	500	500	12.5%	16.7%	32.5%	29.1%	24.7%	32.0%	**24.6%**	12.5%	16.7%	32.5%	29.1%	24.7%	32.0%	**24.6%**
		500	1000	9.6%	12.9%	31.6%	26.2%	23.6%	31.0%	**22.5%**	11.1%	14.8%	32.0%	27.7%	24.1%	31.5%	**23.5%**
		1000	2000	6.6%	9.1%	28.9%	21.5%	21.4%	29.1%	**19.4%**	8.8%	12.0%	30.5%	24.6%	22.8%	30.3%	**21.5%**
		2000	4000	5.1%	5.2%	18.4%	11.8%	16.2%	22.7%	**13.2%**	7.0%	8.6%	24.4%	18.2%	19.5%	26.5%	**17.4%**
		2000	6000	4.2%	3.3%	6.5%	4.9%	9.4%	11.4%	**6.6%**	6.1%	6.8%	18.5%	13.7%	16.1%	21.5%	**13.8%**
	Standalone	500	500														
		500	1000	11.1%	15.0%	29.7%	26.7%	23.2%	30.4%	**22.7%**	11.1%	15.0%	29.7%	26.7%	23.2%	30.4%	**22.7%**
		1000	2000	7.1%	9.9%	24.3%	19.1%	19.9%	26.1%	**17.7%**	9.1%	12.4%	27.0%	22.9%	21.6%	28.2%	**20.2%**
		2000	4000	4.9%	5.7%	17.8%	10.7%	15.8%	20.5%	**12.6%**	7.0%	9.1%	22.4%	16.8%	18.7%	24.3%	**16.4%**
		2000	6000	3.7%	3.1%	12.2%	5.8%	11.1%	14.0%	**8.3%**	5.9%	7.1%	19.0%	13.2%	16.2%	20.9%	**13.7%**
75% Solar 25% Wind	Portfolio	500	500	10.8%	16.9%	33.4%	35.8%	20.1%	33.3%	**25.0%**	10.8%	16.9%	33.4%	35.8%	20.1%	33.3%	**25.0%**
		500	1000	6.2%	11.8%	30.5%	28.6%	17.7%	31.0%	**21.0%**	8.5%	14.3%	32.0%	32.2%	18.9%	32.1%	**23.0%**
		1000	2000	4.0%	7.7%	25.3%	18.4%	16.2%	27.2%	**16.5%**	6.3%	11.0%	28.6%	25.3%	17.6%	29.6%	**19.7%**
		2000	4000	2.9%	4.3%	14.4%	7.1%	12.7%	17.1%	**9.8%**	4.6%	7.6%	21.5%	16.2%	15.1%	23.4%	**14.7%**
		2000	6000	2.6%	2.5%	5.9%	3.3%	8.5%	7.8%	**5.1%**	3.9%	5.9%	16.3%	11.9%	12.9%	18.2%	**11.5%**
	Standalone	500	500														
		500	1000	9.7%	15.0%	29.7%	26.7%	23.2%	30.4%	**22.5%**	9.7%	15.0%	29.7%	26.7%	23.2%	30.4%	**22.5%**
		1000	2000	4.9%	9.6%	25.3%	23.0%	15.7%	27.4%	**17.7%**	7.3%	12.6%	28.4%	28.5%	17.3%	29.7%	**20.6%**
		2000	4000	2.9%	5.1%	17.9%	11.1%	12.3%	20.4%	**11.6%**	5.1%	8.9%	23.1%	19.8%	14.8%	25.1%	**16.1%**
		2000	6000	2.0%	2.6%	11.3%	4.3%	8.6%	12.3%	**6.8%**	4.1%	6.8%	19.2%	14.6%	12.7%	20.8%	**13.0%**

Table A-9 Annual Incremental and Average 4-Hour Storage ELCC Results With Incremental Solar or Wind

ELCC values apply to Storage MW Only
(Inc Ave results apply to Incremental MW tranches; Tot Ave results apply to Total MW)

			Incremental to 2023 Existing Resources							Average of Total Incremental MW						
	Solar MW	BESS MW	2014	2015	2016	2017	2018	2019	Inc Ave	2014	2015	2016	2017	2018	2019	Tot Ave
NFR	250	250	45.5%	44.1%	64.3%	41.7%	58.5%	54.9%	**51.5%**	49.3%	50.4%	69.1%	46.9%	62.7%	60.4%	**56.4%**
NFR	250	500	37.2%	31.7%	52.1%	31.9%	48.0%	42.5%	**40.6%**	43.2%	41.0%	60.6%	39.4%	55.4%	51.4%	**48.5%**
NFR	250	1000	28.8%	15.7%	31.6%	21.6%	33.7%	23.6%	**25.8%**	36.0%	28.3%	46.1%	30.5%	44.5%	37.5%	**37.2%**
NFR	250	2000	22.3%	6.6%	14.5%	13.5%	15.8%	11.1%	**14.0%**	29.2%	17.5%	30.3%	22.0%	30.2%	24.3%	**25.6%**
NFR	500	250	48.2%	43.9%	61.3%	35.7%	63.2%	48.2%	**50.1%**	51.7%	50.3%	65.9%	40.2%	67.8%	53.5%	**54.9%**
NFR	500	500	39.7%	28.5%	48.7%	28.0%	49.3%	36.6%	**38.5%**	45.7%	39.4%	57.3%	34.1%	58.5%	45.1%	**46.7%**
NFR	500	1000	29.4%	13.7%	29.6%	20.3%	31.2%	19.0%	**23.9%**	37.5%	26.5%	43.4%	27.2%	44.9%	32.0%	**35.3%**
NFR	500	2000	21.8%	5.8%	14.3%	13.7%	15.2%	10.4%	**13.5%**	29.6%	16.2%	28.8%	20.5%	30.0%	21.2%	**24.4%**
NFR	1000	250	50.2%	44.4%	55.2%	30.1%	66.5%	41.0%	**47.9%**	53.2%	51.5%	60.7%	33.7%	71.1%	45.4%	**52.6%**
NFR	1000	500	42.6%	28.0%	42.7%	24.0%	50.6%	26.8%	**35.8%**	47.9%	39.8%	51.7%	28.8%	60.8%	36.1%	**44.2%**
NFR	1000	1000	31.5%	12.0%	28.1%	19.0%	28.8%	16.4%	**22.6%**	39.7%	25.9%	39.9%	23.9%	44.8%	26.3%	**33.4%**
NFR	1000	2000	21.4%	5.2%	14.8%	13.7%	15.6%	10.7%	**13.6%**	30.6%	15.5%	27.3%	18.8%	30.2%	18.5%	**23.5%**
NFR	2000	250	52.1%	46.2%	52.6%	28.4%	63.1%	34.6%	**46.2%**	54.5%	52.8%	57.4%	31.5%	68.4%	38.1%	**50.5%**
NFR	2000	500	46.3%	28.5%	40.6%	22.9%	47.9%	22.3%	**34.7%**	50.4%	40.7%	49.0%	27.2%	58.1%	30.2%	**42.6%**
NFR	2000	1000	36.2%	12.2%	29.3%	18.3%	28.0%	16.4%	**23.4%**	43.3%	26.5%	39.2%	22.7%	43.1%	23.3%	**33.0%**
NFR	2000	2000	22.6%	5.0%	18.6%	13.8%	16.7%	11.0%	**14.6%**	33.0%	15.7%	28.9%	18.3%	29.9%	17.2%	**23.8%**
SFR	250	250	45.2%	45.9%	71.7%	46.5%	59.3%	62.6%	**55.2%**	49.2%	52.2%	75.8%	52.6%	63.6%	68.3%	**60.3%**
SFR	250	500	37.0%	32.5%	59.0%	34.5%	48.7%	48.4%	**43.4%**	43.1%	42.3%	67.4%	43.6%	56.2%	58.4%	**51.8%**
SFR	250	1000	29.1%	15.5%	36.9%	22.5%	34.2%	27.7%	**27.6%**	36.1%	28.9%	52.1%	33.0%	45.2%	43.0%	**39.7%**
SFR	250	2000	22.8%	6.5%	16.1%	13.8%	16.1%	11.6%	**14.5%**	29.5%	17.7%	34.1%	23.4%	30.6%	27.3%	**27.1%**
SFR	500	250	45.8%	46.8%	76.0%	42.7%	64.6%	63.3%	**56.5%**	49.4%	53.6%	79.8%	48.5%	69.2%	68.9%	**61.6%**
SFR	500	500	37.9%	30.3%	63.2%	32.2%	50.8%	47.9%	**43.7%**	43.7%	42.0%	71.5%	40.3%	60.0%	58.4%	**52.6%**
SFR	500	1000	29.7%	13.9%	40.2%	21.3%	31.9%	24.8%	**27.0%**	36.7%	27.9%	55.8%	30.8%	46.0%	41.6%	**39.8%**
SFR	500	2000	22.9%	6.1%	16.8%	14.0%	15.5%	10.6%	**14.3%**	29.8%	17.0%	36.3%	22.4%	30.7%	26.1%	**27.1%**
SFR	1000	250	48.5%	48.2%	81.0%	38.9%	69.5%	62.4%	**58.1%**	51.6%	55.4%	85.0%	44.0%	74.1%	68.1%	**63.0%**
SFR	1000	500	40.7%	30.7%	69.8%	29.1%	54.4%	47.1%	**45.3%**	46.2%	43.1%	77.4%	36.6%	64.2%	57.6%	**54.2%**
SFR	1000	1000	31.6%	13.3%	45.4%	20.5%	30.4%	24.4%	**27.6%**	38.9%	28.2%	61.4%	28.5%	47.3%	41.0%	**40.9%**
SFR	1000	2000	22.5%	5.3%	18.9%	14.2%	16.0%	10.5%	**14.6%**	30.7%	16.7%	40.1%	21.4%	31.7%	25.8%	**27.7%**
SFR	2000	250	50.8%	51.8%	85.3%	34.2%	69.4%	59.2%	**58.5%**	53.4%	58.3%	88.6%	38.7%	74.0%	64.9%	**63.0%**
SFR	2000	500	43.9%	33.0%	75.0%	25.6%	53.7%	45.2%	**46.1%**	48.7%	45.7%	81.8%	32.1%	63.9%	55.0%	**54.5%**
SFR	2000	1000	35.8%	14.5%	50.4%	19.0%	30.0%	26.3%	**29.3%**	42.3%	30.1%	66.1%	25.6%	46.9%	40.7%	**41.9%**
SFR	2000	2000	23.0%	5.6%	22.6%	14.0%	17.6%	11.6%	**15.7%**	32.6%	17.8%	44.3%	19.8%	32.3%	26.1%	**28.8%**

Table A-9 (continued) Annual Incremental and Average 4-Hour Storage ELCC Results With Incremental Solar or Wind

ELCC values apply to Storage MW Only
(Inc Ave results apply to Incremental MW tranches; Tot Ave results apply to Total MW)

			Incremental to 2023 Existing Resources							Average of Total Incremental MW						
	Solar MW	BESS MW	2014	2015	2016	2017	2018	2019	Inc Ave	2014	2015	2016	2017	2018	2019	Tot Ave
SLV	250	250	45.4%	47.2%	66.4%	44.0%	60.8%	61.4%	**54.2%**	49.1%	53.3%	70.7%	49.4%	65.8%	67.0%	**59.2%**
	250	500	36.9%	34.1%	54.3%	33.8%	50.4%	47.7%	**42.9%**	43.0%	43.7%	62.5%	41.6%	58.1%	57.4%	**51.0%**
	250	1000	28.5%	17.7%	34.7%	22.3%	34.3%	27.2%	**27.4%**	35.7%	30.7%	48.6%	31.9%	46.2%	42.3%	**39.2%**
	250	2000	22.7%	7.2%	15.6%	13.3%	15.6%	11.3%	**14.3%**	29.2%	19.0%	32.1%	22.6%	30.9%	26.8%	**26.8%**
	500	250	47.6%	51.1%	66.9%	40.4%	67.3%	61.0%	**55.7%**	51.1%	57.0%	71.3%	45.9%	72.1%	66.8%	**60.7%**
	500	500	38.6%	36.0%	55.6%	30.7%	53.8%	46.1%	**43.5%**	44.8%	46.5%	63.4%	38.3%	63.0%	56.5%	**52.1%**
	500	1000	28.6%	17.2%	36.3%	21.3%	33.0%	23.7%	**26.7%**	36.7%	31.9%	49.9%	29.8%	48.0%	40.1%	**39.4%**
	500	2000	22.5%	6.8%	16.3%	12.9%	15.0%	10.5%	**14.0%**	29.6%	19.3%	33.1%	21.3%	31.5%	25.3%	**26.7%**
	1000	250	49.0%	57.1%	72.1%	42.9%	74.2%	60.5%	**59.3%**	52.3%	62.4%	76.5%	48.7%	79.1%	66.4%	**64.2%**
	1000	500	40.7%	42.0%	59.4%	31.8%	60.0%	45.3%	**46.5%**	46.5%	52.2%	67.9%	40.3%	69.5%	55.8%	**55.4%**
	1000	1000	29.5%	19.3%	38.7%	20.7%	34.4%	22.2%	**27.5%**	38.0%	35.7%	53.3%	30.5%	52.0%	39.0%	**41.4%**
	1000	2000	23.0%	7.3%	18.6%	12.9%	15.8%	10.0%	**14.6%**	30.5%	21.5%	36.0%	21.7%	33.9%	24.5%	**28.0%**
	2000	250	50.1%	61.5%	72.8%	51.1%	77.5%	57.2%	**61.7%**	52.7%	65.1%	78.4%	56.0%	81.8%	63.1%	**66.2%**
	2000	500	42.7%	48.7%	61.4%	39.3%	63.2%	42.5%	**49.6%**	47.7%	56.9%	69.9%	47.7%	72.5%	52.8%	**57.9%**
	2000	1000	30.7%	27.3%	40.2%	25.5%	37.0%	21.2%	**30.3%**	39.2%	42.1%	55.1%	36.6%	54.8%	37.0%	**44.1%**
	2000	2000	24.2%	9.7%	22.2%	14.6%	18.5%	10.4%	**16.6%**	31.7%	25.9%	38.6%	25.6%	36.6%	23.7%	**30.4%**
WS	250	250	45.4%	43.4%	63.6%	48.1%	57.4%	54.6%	**52.1%**	49.0%	50.0%	68.0%	54.5%	61.5%	60.1%	**57.2%**
	250	500	38.0%	30.4%	52.1%	35.1%	47.4%	42.4%	**40.9%**	43.5%	40.2%	60.1%	44.8%	54.4%	51.2%	**49.0%**
	250	1000	29.7%	14.9%	34.0%	22.4%	34.4%	24.9%	**26.7%**	36.6%	27.5%	47.0%	33.6%	44.4%	38.1%	**37.9%**
	250	2000	21.6%	6.6%	16.1%	12.9%	16.2%	11.3%	**14.1%**	29.1%	17.1%	31.6%	23.3%	30.3%	24.7%	**26.0%**
	500	250	47.5%	43.6%	61.3%	45.5%	59.7%	48.4%	**51.0%**	50.6%	50.4%	66.0%	51.6%	64.0%	53.9%	**56.1%**
	500	500	40.3%	27.5%	50.7%	33.9%	48.1%	36.6%	**39.5%**	45.4%	39.0%	58.3%	42.7%	56.1%	45.3%	**47.8%**
	500	1000	31.9%	13.5%	34.6%	21.5%	32.0%	20.1%	**25.6%**	38.6%	26.2%	46.5%	32.1%	44.0%	32.7%	**36.7%**
	500	2000	21.1%	6.1%	16.9%	12.4%	15.6%	10.2%	**13.7%**	29.9%	16.1%	31.7%	22.3%	29.8%	21.4%	**25.2%**
	1000	250	49.7%	46.4%	62.1%	45.5%	63.8%	40.1%	**51.3%**	52.3%	53.1%	66.0%	51.6%	68.3%	45.1%	**56.1%**
	1000	500	43.5%	28.5%	51.5%	33.1%	48.7%	28.9%	**39.0%**	47.9%	40.8%	58.8%	42.3%	58.5%	37.0%	**47.6%**
	1000	1000	36.2%	12.7%	35.9%	20.4%	28.9%	14.6%	**24.8%**	42.0%	26.8%	47.3%	31.4%	43.7%	25.8%	**36.2%**
	1000	2000	22.3%	5.6%	18.9%	11.5%	15.8%	10.6%	**14.1%**	32.1%	16.2%	33.1%	21.4%	29.8%	18.2%	**25.1%**
	2000	250	51.2%	52.9%	66.0%	47.3%	65.3%	37.2%	**53.3%**	53.8%	58.6%	70.5%	52.4%	70.0%	41.5%	**57.8%**
	2000	500	46.2%	33.8%	52.3%	35.4%	48.1%	23.5%	**39.9%**	50.0%	46.2%	61.4%	43.9%	59.1%	32.5%	**48.8%**
	2000	1000	40.3%	15.3%	35.4%	22.5%	28.4%	15.0%	**26.2%**	45.2%	30.8%	48.4%	33.2%	43.7%	23.8%	**37.5%**
	2000	2000	27.4%	5.7%	21.6%	12.6%	17.3%	10.1%	**15.8%**	36.3%	18.2%	35.0%	22.9%	30.5%	16.9%	**26.6%**

Table A-9 (continued) Annual Incremental and Average 4-Hour Storage ELCC Results With Incremental Solar or Wind

ELCC values apply to Storage MW Only
(Inc Ave results apply to Incremental MW tranches; Tot Ave results apply to Total MW)

			Incremental to 2023 Existing Resources							Average of Total Incremental MW						
	Solar MW	BESS MW	2014	2015	2016	2017	2018	2019	Inc Ave	2014	2015	2016	2017	2018	2019	Tot Ave
SE	250	250	47.7%	44.4%	63.7%	43.1%	58.0%	58.6%	**52.6%**	51.1%	50.9%	67.7%	48.6%	61.7%	64.3%	**57.4%**
SE	250	500	39.3%	31.9%	52.6%	32.8%	47.9%	45.3%	**41.6%**	45.2%	41.4%	60.1%	40.7%	54.8%	54.8%	**49.5%**
SE	250	1000	30.3%	16.1%	34.8%	22.5%	34.2%	25.6%	**27.2%**	37.7%	28.7%	47.5%	31.6%	44.5%	40.2%	**38.4%**
SE	250	2000	22.4%	6.7%	16.2%	14.0%	16.2%	10.6%	**14.4%**	30.1%	17.7%	31.8%	22.8%	30.4%	25.4%	**26.4%**
SE	500	250	50.6%	44.7%	61.5%	37.5%	61.2%	56.3%	**52.0%**	53.9%	51.4%	65.3%	42.5%	65.8%	62.3%	**56.9%**
SE	500	500	42.6%	30.7%	51.4%	30.1%	49.1%	41.9%	**41.0%**	48.2%	41.0%	58.4%	36.3%	57.4%	52.1%	**48.9%**
SE	500	1000	32.8%	15.0%	35.4%	21.3%	31.8%	22.3%	**26.4%**	40.5%	28.0%	46.9%	28.8%	44.6%	37.2%	**37.7%**
SE	500	2000	21.9%	6.1%	16.9%	14.4%	15.5%	10.4%	**14.2%**	31.2%	17.1%	31.9%	21.6%	30.1%	23.8%	**25.9%**
SE	1000	250	53.1%	49.5%	61.1%	33.5%	66.0%	52.9%	**52.7%**	56.0%	55.2%	64.7%	37.6%	70.8%	58.7%	**57.2%**
SE	1000	500	45.9%	31.1%	51.3%	27.8%	49.8%	39.0%	**40.8%**	50.9%	43.2%	58.0%	32.7%	60.3%	48.8%	**49.0%**
SE	1000	1000	36.7%	14.7%	38.2%	21.1%	29.2%	20.4%	**26.7%**	43.8%	28.9%	48.1%	26.9%	44.7%	34.6%	**37.9%**
SE	1000	2000	23.1%	5.5%	19.3%	15.5%	15.6%	10.1%	**14.9%**	33.5%	17.2%	33.7%	21.2%	30.2%	22.4%	**26.4%**
SE	2000	250	54.7%	55.5%	61.4%	33.3%	66.6%	49.6%	**53.5%**	57.1%	60.6%	63.9%	36.5%	71.2%	55.4%	**57.4%**
SE	2000	500	48.8%	38.4%	54.7%	27.2%	48.5%	35.8%	**42.2%**	52.9%	49.5%	59.3%	31.8%	59.9%	45.6%	**49.8%**
SE	2000	1000	40.0%	18.7%	42.3%	21.2%	28.6%	19.7%	**28.4%**	46.4%	34.1%	50.8%	26.5%	44.3%	32.7%	**39.1%**
SE	2000	2000	26.8%	6.1%	23.6%	17.2%	17.1%	11.3%	**17.0%**	36.6%	20.1%	37.2%	21.8%	30.7%	22.0%	**28.1%**
BTM	250	250	43.9%	45.4%	67.9%	47.7%	58.0%	58.5%	**53.6%**	47.9%	51.3%	72.4%	53.2%	61.0%	63.8%	**58.3%**
BTM	250	500	36.1%	32.9%	55.3%	35.2%	48.8%	46.0%	**42.4%**	42.0%	42.1%	63.9%	44.2%	54.9%	54.9%	**50.3%**
BTM	250	1000	28.3%	16.9%	33.6%	22.8%	36.6%	26.4%	**27.5%**	35.2%	29.5%	48.7%	33.5%	45.8%	40.6%	**38.9%**
BTM	250	2000	22.4%	6.8%	14.9%	13.6%	17.1%	11.6%	**14.4%**	28.8%	18.2%	31.8%	23.6%	31.5%	26.1%	**26.7%**
BTM	125	125	51.8%	57.4%	77.7%	53.4%	68.4%	66.5%	**62.5%**	51.8%	57.4%	77.7%	53.4%	68.4%	66.5%	**62.5%**
BTM	500	250	44.7%	44.8%	68.5%	42.7%	60.8%	55.3%	**52.8%**	48.2%	51.1%	73.1%	48.1%	64.6%	60.9%	**57.7%**
BTM	500	500	36.3%	31.5%	55.6%	33.2%	50.9%	42.2%	**41.6%**	42.3%	41.3%	64.4%	40.6%	57.7%	51.5%	**49.6%**
BTM	500	1000	28.0%	15.2%	33.1%	21.5%	36.5%	23.0%	**26.2%**	35.2%	28.2%	48.7%	31.1%	47.1%	37.3%	**37.9%**
BTM	500	2000	22.1%	6.4%	14.6%	13.7%	17.3%	10.7%	**14.1%**	28.6%	17.3%	31.7%	22.4%	32.2%	24.0%	**26.0%**
BTM	125	125	51.6%	58.3%	78.4%	46.3%	72.5%	60.1%	**61.2%**	51.6%	58.3%	78.4%	46.3%	72.5%	60.1%	**61.2%**
BTM	1000	250	45.0%	44.9%	68.7%	37.0%	64.9%	49.6%	**51.7%**	48.3%	51.6%	73.6%	41.6%	68.7%	54.9%	**56.5%**
BTM	1000	500	37.0%	28.8%	55.2%	29.2%	54.3%	35.2%	**40.0%**	42.6%	40.2%	64.4%	35.4%	61.5%	45.0%	**48.2%**
BTM	1000	1000	27.9%	13.4%	33.4%	20.0%	36.7%	18.2%	**24.9%**	35.3%	26.8%	48.9%	27.7%	49.1%	31.6%	**36.6%**
BTM	1000	2000	22.0%	5.9%	14.8%	13.7%	17.5%	10.0%	**14.0%**	28.6%	16.3%	31.8%	20.7%	33.3%	20.8%	**25.3%**

Table A-9 (continued) Annual Incremental and Average 4-Hour Storage ELCC Results With Incremental Solar or Wind

ELCC values apply to Storage MW Only
(Inc Ave results apply to Incremental MW tranches; Tot Ave results apply to Total MW)

			Incremental to 2023 Existing Resources							Average of Total Incremental MW						
	Solar MW	BESS MW	2014	2015	2016	2017	2018	2019	Inc Ave	2014	2015	2016	2017	2018	2019	Tot Ave
Diversified Solar	500	250	47.9%	44.9%	64.1%	40.5%	63.1%	53.3%	52.3%	51.1%	51.9%	68.5%	45.8%	67.4%	59.0%	57.3%
	500	500	37.0%	25.6%	49.7%	29.0%	46.2%	36.6%	37.4%	45.2%	41.1%	60.8%	38.6%	58.9%	49.6%	49.0%
	500	1000	37.5%	27.8%	47.5%	29.6%	45.4%	35.2%	37.2%	37.5%	27.8%	47.5%	29.6%	45.4%	35.2%	37.2%
	500	2000	22.0%	6.3%	16.2%	13.2%	15.3%	10.3%	13.9%	29.7%	17.0%	31.9%	21.4%	30.4%	22.7%	25.5%
	1000	250	52.8%	54.6%	66.8%	41.8%	73.1%	50.7%	56.6%	52.8%	54.6%	66.8%	41.8%	73.1%	50.7%	56.6%
	1000	500	42.2%	30.3%	50.6%	28.1%	53.2%	33.5%	39.7%	47.5%	42.5%	58.7%	35.0%	63.1%	42.1%	48.2%
	1000	1000	29.7%	10.6%	30.1%	17.4%	25.3%	14.6%	21.3%	40.1%	28.1%	46.5%	27.1%	46.6%	29.5%	36.3%
	1000	2000	30.9%	16.9%	31.9%	19.9%	31.0%	19.8%	25.1%	30.9%	16.9%	31.9%	19.9%	31.0%	19.8%	25.1%
	2000	250	54.8%	59.8%	64.4%	46.5%	74.0%	41.2%	56.8%	54.8%	59.8%	64.4%	46.5%	74.0%	41.2%	56.8%
	2000	500	50.7%	47.9%	56.3%	38.7%	63.2%	33.3%	48.3%	50.7%	47.9%	56.3%	38.7%	63.2%	33.3%	48.3%
	2000	1000	37.9%	16.1%	33.8%	19.5%	29.5%	16.2%	25.5%	44.3%	32.0%	45.1%	29.1%	46.3%	24.7%	36.9%
	2000	2000	20.6%	4.4%	18.0%	11.3%	15.9%	10.1%	13.4%	34.0%	18.8%	32.8%	20.8%	31.9%	17.7%	26.0%
	4000	250	56.9%	64.8%	61.2%	54.4%	72.6%	39.4%	58.2%	56.9%	64.8%	61.2%	54.4%	72.6%	39.4%	58.2%
	4000	500	51.2%	47.2%	45.5%	38.2%	52.7%	26.5%	43.6%	54.1%	56.0%	53.4%	46.3%	62.7%	32.9%	50.9%
	4000	1000	43.8%	25.8%	34.2%	24.2%	31.4%	17.7%	29.5%	48.9%	40.9%	43.8%	35.3%	47.1%	25.3%	40.2%
	4000	2000	29.9%	7.8%	23.0%	14.8%	20.2%	11.8%	17.9%	39.4%	24.3%	33.4%	25.0%	33.6%	18.6%	29.1%
Diversified Wind	500	250	46.9%	43.0%	66.9%	54.7%	53.8%	61.0%	54.4%	50.6%	49.2%	71.4%	60.1%	57.6%	66.2%	59.2%
	500	500	35.6%	28.2%	49.7%	37.4%	42.2%	44.7%	39.7%	44.2%	40.2%	62.7%	50.9%	51.0%	57.2%	51.0%
	500	1000	37.2%	28.4%	47.6%	38.0%	42.3%	43.4%	39.5%	37.2%	28.4%	47.6%	38.0%	42.3%	43.4%	39.5%
	500	2000	23.4%	6.7%	15.2%	15.0%	17.4%	13.1%	15.1%	30.3%	17.5%	31.4%	26.5%	29.8%	28.2%	27.3%
	1000	250	52.4%	46.8%	70.6%	60.4%	55.2%	65.3%	58.5%	52.4%	46.8%	70.6%	60.4%	55.2%	65.3%	58.5%
	1000	500	40.1%	28.8%	53.5%	43.6%	41.5%	46.8%	42.4%	46.3%	37.8%	62.1%	52.0%	48.3%	56.0%	50.4%
	1000	1000	30.0%	11.2%	25.3%	23.0%	28.2%	23.4%	23.5%	39.1%	26.0%	46.7%	39.2%	39.7%	42.1%	38.8%
	1000	2000	31.2%	15.9%	30.9%	28.0%	28.5%	27.6%	27.0%	31.2%	15.9%	30.9%	28.0%	28.5%	27.6%	27.0%
	2000	250	55.3%	42.0%	67.8%	58.9%	49.7%	62.4%	56.0%	55.3%	42.0%	67.8%	58.9%	49.7%	62.4%	56.0%
	2000	500	49.0%	33.5%	59.3%	50.9%	43.3%	54.2%	48.4%	49.0%	33.5%	59.3%	50.9%	43.3%	54.2%	48.4%
	2000	1000	33.5%	11.2%	30.7%	28.5%	28.2%	27.3%	26.6%	41.3%	22.3%	45.0%	39.7%	35.7%	40.8%	37.5%
	2000	2000	21.3%	4.3%	13.7%	18.7%	15.7%	12.2%	14.3%	32.4%	13.6%	30.6%	30.1%	26.6%	27.6%	26.8%
	4000	250	66.5%	37.5%	61.5%	53.4%	41.8%	54.7%	52.6%	66.5%	37.5%	61.5%	53.4%	41.8%	54.7%	52.6%
	4000	500	49.9%	20.9%	41.2%	39.1%	32.2%	38.9%	37.0%	58.2%	29.2%	51.4%	46.2%	37.0%	46.8%	44.8%
	4000	1000	34.6%	8.4%	26.9%	29.3%	25.5%	26.3%	25.2%	46.4%	18.8%	39.1%	37.8%	31.3%	36.5%	35.0%
	4000	2000	23.3%	4.0%	17.6%	24.2%	17.5%	16.4%	17.2%	34.9%	11.4%	28.4%	31.0%	24.4%	26.4%	26.1%

Table A-10 Annual Incremental and Average 4-Hour Solar Hybrid Storage ELCC Results

ELCC values apply to Storage MW Only
(Inc Ave results apply to Incremental MW tranches; Tot Ave results apply to Total MW)

				Incremental to 2023 Existing Resources							Average of Total Incremental MW							
	Solar MW	Incremental Storage MW	Total Storage MW	2014	2015	2016	2017	2018	2019	Inc Ave	2014	2015	2016	2017	2018	2019	Tot Ave	
Standalone Storage	250	125	125	48.6%	55.1%	68.5%	52.3%	71.2%	66.5%	**60.4%**	48.6%	55.1%	68.5%	52.3%	71.2%	66.5%	**60.4%**	
		125	250	43.3%	43.9%	60.3%	42.3%	60.1%	55.3%	**50.9%**	46.0%	49.5%	64.4%	47.3%	65.6%	60.9%	**55.6%**	
	500	250	250	48.4%	50.7%	63.3%	42.8%	68.0%	56.7%	**55.0%**	48.4%	50.7%	63.3%	42.8%	68.0%	56.7%	**55.0%**	
		250	500	38.4%	29.7%	49.0%	30.4%	50.1%	38.3%	**39.3%**	43.4%	40.2%	56.1%	36.6%	59.1%	47.5%	**47.1%**	
Solar Hybrid	250	125	125	48.7%	52.5%	66.7%	44.9%	63.5%	55.6%	**55.3%**	48.7%	52.5%	66.7%	44.9%	63.5%	55.6%	**55.3%**	**8.34%**
		125	250	42.7%	41.8%	59.3%	38.2%	54.1%	44.0%	**46.7%**	45.7%	47.2%	63.0%	41.5%	58.8%	49.8%	**51.0%**	**8.29%**
	500	250	250	48.2%	49.4%	62.5%	38.7%	65.5%	51.5%	**52.6%**	48.2%	49.4%	62.5%	38.7%	65.5%	51.5%	**52.6%**	**4.28%**
		250	500	37.4%	27.5%	47.8%	28.6%	46.8%	30.3%	**36.4%**	42.8%	38.4%	55.1%	33.6%	56.2%	40.9%	**44.5%**	**5.58%**

Table A-11 Annual Incremental and Average 4-Hour Storage ELCC Results with Incremental Diversified Solar and Wind

ELCC values apply to Storage MW Only
(Inc Ave results apply to Incremental MW tranches; Tot Ave results apply to Total MW)

			Incremental to 2023 Existing Resources							Average of Total Incremental MW						
	Incremental Solar/Wind MW	Total MW	2014	2015	2016	2017	2018	2019	Inc Ave	2014	2015	2016	2017	2018	2019	Tot Ave
250 MW	0	0	46.8%	51.4%	71.5%	58.5%	58.3%	66.4%	**58.8%**	46.8%	51.4%	71.5%	58.5%	58.3%	66.4%	**58.8%**
	500	500	50.9%	50.3%	69.2%	52.1%	61.7%	62.6%	**57.8%**	50.9%	50.3%	69.2%	52.1%	61.7%	62.6%	**57.8%**
	500	1000	53.4%	47.0%	63.0%	39.0%	65.7%	49.9%	**53.0%**	52.2%	48.6%	66.1%	45.5%	63.7%	56.3%	**55.4%**
	1000	2000	58.0%	47.1%	50.2%	35.0%	53.0%	35.2%	**46.4%**	55.1%	47.9%	58.1%	40.3%	58.4%	45.7%	**50.9%**
	2000	4000	64.8%	52.4%	44.1%	61.7%	35.5%	22.2%	**46.8%**	59.9%	50.1%	51.1%	51.0%	46.9%	34.0%	**48.8%**
500 MW	0	0	41.0%	42.3%	63.2%	48.8%	52.6%	58.0%	**51.0%**	41.0%	42.3%	63.2%	48.8%	52.6%	58.0%	**51.0%**
	500	500	44.9%	40.7%	60.9%	43.4%	54.3%	53.6%	**49.6%**	44.9%	40.7%	60.9%	43.4%	54.3%	53.6%	**49.6%**
	500	1000	48.6%	36.4%	54.2%	33.6%	54.1%	41.6%	**44.7%**	46.8%	38.5%	57.5%	38.5%	54.2%	47.6%	**47.2%**
	1000	2000	53.9%	37.5%	41.2%	30.0%	44.3%	26.4%	**38.9%**	50.3%	38.0%	49.4%	34.2%	49.3%	37.0%	**43.0%**
	2000	4000	61.4%	45.9%	38.0%	49.2%	31.2%	24.2%	**41.6%**	55.9%	42.0%	43.7%	41.7%	40.2%	30.6%	**42.3%**
1000 MW	0	0	34.9%	30.6%	48.8%	36.5%	44.5%	44.1%	**39.9%**	34.9%	30.6%	48.8%	36.5%	44.5%	44.1%	**39.9%**
	500	500	37.4%	27.8%	47.0%	33.0%	43.3%	39.1%	**38.0%**	37.4%	27.8%	47.0%	33.0%	43.3%	39.1%	**38.0%**
	500	1000	41.5%	23.8%	41.8%	27.4%	39.8%	28.0%	**33.7%**	39.4%	25.8%	44.4%	30.2%	41.6%	33.5%	**35.8%**
	1000	2000	47.2%	25.7%	34.0%	25.7%	32.8%	21.6%	**31.2%**	43.3%	25.8%	39.2%	28.0%	37.2%	27.6%	**33.5%**
	2000	4000	54.9%	31.1%	31.5%	36.2%	23.8%	21.2%	**33.1%**	49.1%	28.4%	35.3%	32.1%	30.5%	24.4%	**33.3%**
2000 MW	0	0	29.0%	19.1%	32.2%	25.0%	31.0%	28.5%	**27.5%**	29.0%	19.1%	32.2%	25.0%	31.0%	28.5%	**27.5%**
	500	500	30.1%	17.1%	31.3%	23.5%	29.7%	25.2%	**26.1%**	30.1%	17.1%	31.3%	23.5%	29.7%	25.2%	**26.1%**
	500	1000	32.0%	14.1%	29.0%	21.4%	27.4%	19.0%	**23.8%**	31.0%	15.6%	30.1%	22.4%	28.6%	22.1%	**25.0%**
	1000	2000	36.2%	15.5%	26.5%	21.6%	25.0%	16.5%	**23.5%**	33.6%	15.5%	28.3%	22.0%	26.8%	19.3%	**24.3%**
	2000	4000	43.6%	18.4%	30.6%	27.7%	21.0%	18.7%	**26.7%**	38.6%	16.9%	29.5%	24.9%	23.9%	19.0%	**25.5%**
4000 MW	0	0	19.6%	11.1%	18.9%	15.7%	20.0%	17.1%	**17.1%**	19.6%	11.1%	18.9%	15.7%	20.0%	17.1%	**17.1%**
	1000	1000	21.6%	9.2%	18.9%	15.1%	19.8%	14.5%	**16.5%**	21.6%	9.2%	18.9%	15.1%	19.8%	14.5%	**16.5%**
	1000	2000	24.3%	7.4%	17.6%	13.8%	19.0%	9.2%	**15.2%**	22.9%	8.3%	18.2%	14.5%	19.4%	11.8%	**15.9%**
	2000	4000	28.3%	10.1%	24.2%	18.3%	18.7%	13.9%	**18.9%**	25.6%	9.2%	21.2%	16.4%	19.1%	12.9%	**17.4%**

Table A-12 Annual Incremental and Average 4-Hour Storage ELCC Results with Combinations of Incremental Solar and Wind

ELCC values apply to Storage MW Only
(Inc Ave results apply to Incremental MW tranches; Tot Ave results apply to Total MW)

				Incremental to 2023 Existing Resources							Average of Total Incremental MW						
		Incremental Solar/Wind MW	Total MW	2014	2015	2016	2017	2018	2019	Inc Ave	2014	2015	2016	2017	2018	2019	Tot Ave
250 MW 4-Hour Duration Storage	75% Solar 25% Wind	0	0	46.8%	51.4%	71.5%	58.5%	58.3%	66.4%	**58.8%**	46.8%	51.4%	71.5%	58.5%	58.3%	66.4%	**58.8%**
		500	500	50.5%	50.6%	68.8%	47.7%	65.2%	60.9%	**57.3%**	50.5%	50.6%	68.8%	47.7%	65.2%	60.9%	**57.3%**
		500	1000	54.6%	51.8%	62.8%	36.9%	71.7%	44.3%	**53.7%**	52.5%	51.2%	65.8%	42.3%	68.4%	52.6%	**55.5%**
		1000	2000	57.8%	54.9%	55.0%	44.0%	63.1%	29.1%	**50.7%**	55.2%	53.1%	60.4%	43.2%	65.8%	40.9%	**53.1%**
		2000	4000	60.9%	60.7%	51.0%	68.5%	51.3%	32.8%	**54.2%**	58.0%	56.9%	55.7%	55.9%	58.5%	36.8%	**53.6%**
	50% Solar 50% Wind	0	0	46.8%	51.4%	71.5%	58.5%	58.3%	66.4%	**58.8%**	46.8%	51.4%	71.5%	58.5%	58.3%	66.4%	**58.8%**
		500	500	50.9%	50.3%	69.2%	52.1%	61.7%	62.6%	**57.8%**	50.9%	50.3%	69.2%	52.1%	61.7%	62.6%	**57.8%**
		500	1000	53.4%	47.0%	63.0%	39.0%	65.7%	49.9%	**53.0%**	52.2%	48.6%	66.1%	45.5%	63.7%	56.3%	**55.4%**
		1000	2000	58.0%	47.1%	50.2%	35.0%	53.0%	35.2%	**46.4%**	55.1%	47.9%	58.1%	40.3%	58.4%	45.7%	**50.9%**
		2000	4000	64.8%	52.4%	44.1%	61.7%	35.5%	22.2%	**46.8%**	59.9%	50.1%	51.1%	51.0%	46.9%	34.0%	**48.8%**
	25% Solar 75% Wind	0	0	46.8%	51.4%	71.5%	58.5%	58.3%	66.4%	**58.8%**	46.8%	51.4%	71.5%	58.5%	58.3%	66.4%	**58.8%**
		500	500	50.3%	49.8%	70.4%	56.1%	59.3%	64.5%	**58.4%**	50.3%	49.8%	70.4%	56.1%	59.3%	64.5%	**58.4%**
		500	1000	55.3%	45.4%	66.6%	50.6%	56.2%	58.1%	**55.4%**	52.8%	47.6%	68.5%	53.4%	57.8%	61.3%	**56.9%**
		1000	2000	57.6%	39.5%	54.6%	38.6%	45.6%	44.1%	**46.7%**	55.2%	43.5%	61.5%	46.0%	51.7%	52.7%	**51.8%**
		2000	4000	68.6%	41.2%	36.4%	32.6%	31.8%	26.6%	**39.5%**	61.9%	42.4%	48.9%	39.3%	41.7%	39.7%	**45.6%**
500 MW 4-Hour Duration Storage	75% Solar 25% Wind	0	0	41.0%	42.3%	63.2%	48.8%	52.6%	58.0%	**51.0%**	41.0%	42.3%	63.2%	48.8%	52.6%	58.0%	**51.0%**
		500	500	44.6%	40.7%	60.7%	40.1%	56.8%	51.6%	**49.1%**	44.6%	40.7%	60.7%	40.1%	56.8%	51.6%	**49.1%**
		500	1000	50.0%	40.0%	54.1%	31.4%	59.9%	36.0%	**45.2%**	47.3%	40.4%	57.4%	35.7%	58.3%	43.8%	**47.1%**
		1000	2000	54.8%	45.7%	46.4%	35.4%	53.1%	21.8%	**42.9%**	51.0%	43.0%	51.9%	35.6%	55.7%	32.8%	**45.0%**
		2000	4000	58.3%	55.3%	43.1%	57.7%	40.9%	27.3%	**47.1%**	54.7%	49.1%	47.5%	46.6%	48.3%	30.1%	**46.1%**
	50% Solar 50% Wind	0	0	41.0%	42.3%	63.2%	48.8%	52.6%	58.0%	**51.0%**	41.0%	42.3%	63.2%	48.8%	52.6%	58.0%	**51.0%**
		500	500	44.9%	40.7%	60.9%	43.4%	54.3%	53.6%	**49.6%**	44.9%	40.7%	60.9%	43.4%	54.3%	53.6%	**49.6%**
		500	1000	48.6%	36.4%	54.2%	33.6%	54.1%	41.6%	**44.7%**	46.8%	38.5%	57.5%	38.5%	54.2%	47.6%	**47.2%**
		1000	2000	53.9%	37.5%	41.2%	30.0%	44.3%	26.4%	**38.9%**	50.3%	38.0%	49.4%	34.2%	49.3%	37.0%	**43.0%**
		2000	4000	61.4%	45.9%	38.0%	49.2%	31.2%	24.2%	**41.6%**	55.9%	42.0%	43.7%	41.7%	40.2%	30.6%	**42.3%**
	25% Solar 75% Wind	0	0	44.2%	40.2%	62.7%	50.9%	51.0%	57.2%	**51.0%**	41.0%	42.3%	63.2%	48.8%	52.6%	58.0%	**51.0%**
		500	500	44.1%	40.2%	61.6%	46.6%	52.3%	55.4%	**50.0%**	44.1%	40.2%	61.6%	46.6%	52.3%	55.4%	**50.0%**
		500	1000	49.5%	35.8%	56.9%	42.4%	48.3%	49.0%	**47.0%**	46.8%	38.0%	59.3%	44.5%	50.3%	52.2%	**48.5%**
		1000	2000	52.9%	31.1%	44.9%	32.6%	38.5%	37.5%	**39.6%**	49.8%	34.5%	52.1%	38.5%	44.4%	44.9%	**44.0%**
		2000	4000	61.7%	33.3%	30.5%	28.3%	26.9%	24.6%	**34.2%**	55.8%	33.9%	41.3%	33.4%	35.6%	34.7%	**39.1%**

Table A-12 (continued) Annual Incremental and Average 4-Hour Storage ELCC Results with Combinations of Incremental Solar and Wind

ELCC values apply to Storage MW Only
(Inc Ave results apply to Incremental MW tranches; Tot Ave results apply to Total MW)

				Incremental to 2023 Existing Resources							Average of Total Incremental MW						
		Incremental Solar/Wind MW	Total MW	2014	2015	2016	2017	2018	2019	Inc Ave	2014	2015	2016	2017	2018	2019	Tot Ave
1000 MW 4-Hour Duration Storage	75% Solar 25% Wind	0	0	34.9%	30.6%	48.8%	36.5%	44.5%	44.1%	**39.9%**	34.9%	30.6%	48.8%	36.5%	44.5%	44.1%	**39.9%**
		500	500	37.2%	27.6%	47.1%	30.9%	44.5%	37.1%	**37.4%**	37.2%	27.6%	47.1%	30.9%	44.5%	37.1%	**37.4%**
		500	1000	42.4%	25.8%	42.5%	25.0%	42.8%	24.3%	**33.8%**	39.8%	26.7%	44.8%	27.9%	43.7%	30.7%	**35.6%**
		1000	2000	48.9%	30.5%	38.1%	27.6%	39.0%	18.4%	**33.7%**	44.4%	28.6%	41.4%	27.7%	41.3%	24.5%	**34.7%**
		2000	4000	54.5%	41.0%	36.0%	43.7%	31.8%	23.7%	**38.5%**	49.4%	34.8%	38.7%	35.7%	36.6%	24.1%	**36.6%**
	50% Solar 50% Wind	0	0	34.9%	30.6%	48.8%	36.5%	44.5%	44.1%	**39.9%**	34.9%	30.6%	48.8%	36.5%	44.5%	44.1%	**39.9%**
		500	500	37.4%	27.8%	47.0%	33.0%	43.3%	39.1%	**38.0%**	37.4%	27.8%	47.0%	33.0%	43.3%	39.1%	**38.0%**
		500	1000	41.5%	23.8%	41.8%	27.4%	39.8%	28.0%	**33.7%**	39.4%	25.8%	44.4%	30.2%	41.6%	33.5%	**35.8%**
		1000	2000	47.2%	25.7%	34.0%	25.7%	32.8%	21.6%	**31.2%**	43.3%	25.8%	39.2%	28.0%	37.2%	27.6%	**33.5%**
		2000	4000	54.9%	31.1%	31.5%	36.2%	23.8%	21.2%	**33.1%**	49.1%	28.4%	35.3%	32.1%	30.5%	24.4%	**33.3%**
	25% Solar 75% Wind	0	0	34.9%	30.6%	48.8%	36.5%	44.5%	44.1%	**39.9%**	34.9%	30.6%	48.8%	36.5%	44.5%	44.1%	**39.9%**
		500	500	37.1%	28.2%	47.3%	35.2%	42.7%	41.3%	**38.6%**	37.1%	28.2%	47.3%	35.2%	42.7%	41.3%	**38.6%**
		500	1000	41.4%	23.7%	42.5%	32.6%	37.0%	35.5%	**35.5%**	39.2%	26.0%	44.9%	33.9%	39.8%	38.4%	**37.0%**
		1000	2000	45.4%	20.1%	34.8%	28.7%	29.8%	27.1%	**31.0%**	42.3%	23.0%	39.8%	31.3%	34.8%	32.8%	**34.0%**
		2000	4000	52.1%	22.6%	28.5%	26.8%	22.4%	23.0%	**29.2%**	47.2%	22.8%	34.1%	29.0%	28.6%	27.9%	**31.6%**
2000 MW 4-Hour Duration Storage	75% Solar 25% Wind	0	0	29.0%	19.1%	32.2%	25.0%	31.0%	28.5%	**27.5%**	29.0%	19.1%	32.2%	25.0%	31.0%	28.5%	**27.5%**
		500	500	29.8%	17.0%	31.4%	22.3%	30.1%	23.9%	**25.7%**	29.8%	17.0%	31.4%	22.3%	30.1%	23.9%	**25.7%**
		500	1000	32.3%	15.0%	29.6%	19.4%	28.9%	17.4%	**23.7%**	31.0%	16.0%	30.5%	20.8%	29.5%	20.6%	**24.7%**
		1000	2000	37.3%	18.2%	30.2%	20.8%	28.8%	14.7%	**25.0%**	34.2%	17.1%	30.4%	20.8%	29.1%	17.6%	**24.9%**
		2000	4000	45.7%	24.3%	31.0%	30.0%	25.6%	18.7%	**29.2%**	39.9%	20.7%	30.7%	25.4%	27.4%	18.2%	**27.0%**
	50% Solar 50% Wind	0	0	29.0%	19.1%	32.2%	25.0%	31.0%	28.5%	**27.5%**	29.0%	19.1%	32.2%	25.0%	31.0%	28.5%	**27.5%**
		500	500	30.1%	17.1%	31.3%	23.5%	29.7%	25.2%	**26.1%**	30.1%	17.1%	31.3%	23.5%	29.7%	25.2%	**26.1%**
		500	1000	32.0%	14.1%	29.0%	21.4%	27.4%	19.0%	**23.8%**	31.0%	15.6%	30.1%	22.4%	28.6%	22.1%	**25.0%**
		1000	2000	36.2%	15.5%	26.5%	21.6%	25.0%	16.5%	**23.5%**	33.6%	15.5%	28.3%	22.0%	26.8%	19.3%	**24.3%**
		2000	4000	43.6%	18.4%	30.6%	27.7%	21.0%	18.7%	**26.7%**	38.6%	16.9%	29.5%	24.9%	23.9%	19.0%	**25.5%**
	25% Solar 75% Wind	0	0	29.0%	19.1%	32.2%	25.0%	31.0%	28.5%	**27.5%**	29.0%	19.1%	32.2%	25.0%	31.0%	28.5%	**27.5%**
		500	500	30.1%	17.4%	31.5%	24.9%	29.7%	26.6%	**26.7%**	30.1%	17.4%	31.5%	24.9%	29.7%	26.6%	**26.7%**
		500	1000	32.1%	14.6%	28.5%	24.7%	26.5%	23.6%	**25.0%**	31.1%	16.0%	30.0%	24.8%	28.1%	25.1%	**25.8%**
		1000	2000	34.5%	12.2%	25.7%	24.7%	23.2%	19.9%	**23.4%**	32.8%	14.1%	27.9%	24.7%	25.7%	22.5%	**24.6%**
		2000	4000	39.5%	13.7%	27.1%	25.6%	19.7%	20.4%	**24.3%**	36.2%	13.9%	27.5%	25.2%	22.7%	21.5%	**24.5%**

Table A-13 Annual Incremental and Average 8-Hour Storage ELCC Results with Combinations of Incremental Solar and Wind

ELCC values apply to Storage MW Only
(Inc Ave results apply to Incremental MW tranches; Tot Ave results apply to Total MW)

			Incremental to 2023 Existing Resources							Average of Total Incremental MW						
	Incremental Solar/Wind MW	Total MW	2014	2015	2016	2017	2018	2019	Inc Ave	2014	2015	2016	2017	2018	2019	Tot Ave
500 MW	0	0	70.0%	60.2%	86.1%	69.7%	85.6%	78.9%	**75.1%**	70.0%	60.2%	86.1%	69.7%	85.6%	78.9%	**75.1%**
	500	500	72.0%	53.7%	80.2%	62.3%	82.9%	68.8%	**70.0%**	72.0%	53.7%	80.2%	62.3%	82.9%	68.8%	**70.0%**
	500	1000	80.3%	47.5%	76.0%	52.7%	72.0%	52.4%	**63.5%**	76.2%	50.6%	78.1%	57.5%	77.4%	60.6%	**66.7%**
	1000	2000	89.9%	49.8%	67.1%	49.3%	61.4%	43.0%	**60.1%**	83.1%	50.2%	72.6%	53.4%	69.4%	51.8%	**63.4%**
	2000	4000	99.4%	62.2%	66.6%	67.9%	48.7%	45.9%	**65.1%**	91.2%	56.2%	69.6%	60.6%	59.1%	48.9%	**64.3%**
1000 MW	0	0	58.3%	38.5%	64.7%	50.5%	62.2%	57.6%	**55.3%**	58.3%	38.5%	64.7%	50.5%	62.2%	57.6%	**55.3%**
	500	500	59.2%	34.1%	59.1%	46.5%	60.7%	48.9%	**51.4%**	59.2%	34.1%	59.1%	46.5%	60.7%	48.9%	**51.4%**
	500	1000	64.0%	28.6%	56.3%	41.9%	55.0%	37.9%	**47.3%**	61.6%	31.3%	57.7%	44.2%	57.9%	43.4%	**49.4%**
	1000	2000	73.2%	31.1%	53.2%	42.4%	50.7%	32.2%	**47.1%**	67.4%	31.2%	55.4%	43.3%	54.3%	37.8%	**48.3%**
	2000	4000	85.8%	38.0%	63.2%	53.7%	42.6%	39.1%	**53.7%**	76.6%	34.6%	59.3%	48.5%	48.4%	38.5%	**51.0%**
2000 MW	0	0	40.1%	23.1%	40.1%	32.3%	39.8%	35.5%	**35.2%**	40.1%	23.1%	40.1%	32.3%	39.8%	35.5%	**35.2%**
	500	500	41.5%	20.8%	37.7%	31.2%	40.0%	31.1%	**33.7%**	41.5%	20.8%	37.7%	31.2%	40.0%	31.1%	**33.7%**
	500	1000	45.9%	17.8%	38.3%	30.2%	40.2%	27.8%	**33.4%**	43.7%	19.3%	38.0%	30.7%	40.1%	29.4%	**33.6%**
	1000	2000	52.2%	19.0%	38.7%	32.0%	41.7%	25.0%	**34.8%**	48.0%	19.1%	38.3%	31.4%	40.9%	27.2%	**34.2%**
	2000	4000	58.4%	22.9%	49.5%	38.4%	38.9%	30.2%	**39.7%**	53.2%	21.0%	43.9%	34.9%	39.9%	28.7%	**36.9%**
4000 MW	0	0	21.3%	13.9%	22.6%	18.0%	22.6%	19.6%	**19.7%**	21.3%	13.9%	22.6%	18.0%	22.6%	19.6%	**19.7%**
	500	500	22.6%	13.0%	23.0%	18.1%	23.0%	18.3%	**19.6%**	22.6%	13.0%	23.0%	18.1%	23.0%	18.3%	**19.6%**
	500	1000	25.5%	11.5%	24.0%	19.3%	24.8%	18.5%	**20.6%**	24.1%	12.2%	23.5%	18.7%	23.9%	18.4%	**20.1%**
	1000	2000	30.7%	12.1%	26.5%	22.0%	30.0%	17.1%	**23.1%**	27.4%	12.2%	25.0%	20.3%	26.9%	17.7%	**21.6%**
	2000	4000	39.1%	14.9%	34.3%	26.9%	38.7%	22.1%	**29.3%**	33.2%	13.5%	29.7%	23.6%	32.8%	19.9%	**25.5%**

Coal Resource Study for the Colorado Public Utilities Commission

For

Public Service Company of Colorado

March 2021

Prepared by
Burnham Coal, LLC
Denver, Colorado

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Exhibit – BLM, Federal Coal Lease Status Map

Definitions/Abbreviations

Annual Energy Outlook: AEO - The AEO is published pursuant to the Department of Energy Organization Act of 1977, which requires the U.S. Energy Information Administration Administrator to prepare annual reports on trends and projections for energy use and supply.

Bureau of Land Management: BLM

Earnings Before Interest, Taxes, Depreciation and Amortization: EBITDA - A financial term used in calculating a company's financial performance; it is sometimes referred to as operating cash flow.

Environmental Impact Statement: EIS

Hydraulic Fracturing or Fracking: An oil and gas well development process that typically involves injecting water, sand, and chemicals under high pressure into a bedrock formation via a well. This process is intended to create new fractures in the rock as well as increase the size, extent, and connectivity of existing fractures. Hydraulic fracturing is a well-stimulation technique used commonly in low-permeability rocks like tight sandstone, shale, and some coal beds to increase oil and/or gas flow to a well from petroleum-bearing rock formations.

Labor Productivity or Productivity: TPMH - Tons Per Man Hour.

Lease-by-Application: LBA - The BLM established the LBA process where companies can nominate reserve blocks for leasing in a competitive bid process. This process has resulted in 27 tracts, containing an estimated 7.9 billion tons of coal, being leased since 1991.

Mega Watts: MW

Metallurgical Coal: Metallurgical coal or coking coal is used in the process of creating coke necessary for iron and steel-making.

Million Tons: MT

Million Tons Per Year: MTY

Mining Ratio or Ratio: BCYT - Measured in Bank Cubic Yards per Ton is the number of yards of overburden moved per ton of coal mined.

Powder River Basin: PRB

Public Service of Colorado: PSCo

Thermal Coal: Thermal coal, also known as steam coal, is used for power and heat generation.

US: United States

US Energy Information Administration: EIA

US Geologic Survey: USGS

Introduction

The Colorado Public Utilities Commission (CPUC) ordered Public Service Company of Colorado (PSCo) to provide an assessment of the status of its coal supply and coal suppliers. This report is prepared in response to this order. Specifically, paragraph 156 of CPUC Decision No. C17-0316 states as follows:

> 156. Given the turbulence in the coal market, we find it necessary for Public Service to provide the Commission an assessment of the status of its coal supply and coal suppliers. We therefore direct the Company to provide two reports: the first to be filed on or before October 31, 2018, and the second to be filed at the time when it files its 2019 ERP. Each report shall provide a market-based assessment of Public Service's suppliers along with the coal production industry in general. Public Service is not required to determine the future cost structures and profitability of individual suppliers or mines. Instead, the Company may use commercially available resources and professional services that provide assessments of the financial health and future viability of the coal industry as relevant to Public Service. Each report shall also include a detailed discussion of the factors which affect the future coal cost and supply.

In accordance with the CPUC's order, PSCo filed the first report on October 31, 2018. This second report prepared for PSCo will be filed with PSCo's 2021 Electric Resource Plan (ERP), as the 2019 ERP referenced in the Decision is now the 2021 ERP.

Executive Summary

Public Service Company of Colorado generates electricity at eight coal fired units at four power plants (Comanche, Pawnee, Hayden and Craig). Most of this coal comes from the Powder River Basin (PRB) in Wyoming and the balance from mines in northwestern Colorado. The PRB is the largest coal producing region in the United States (US) with 12 surface mines that produced 210.0 million tons (MT) in 2020.

In 2020, the Comanche and Pawnee collectively received 4.6 MT of coal from four PRB coal mines: Black Thunder, Belle Ayr, Buckskin and Eagle Butte. (Deliveries to the Comanche plant were curtailed by outages caused by issues with the turbine and generator in Unit 3 in 2020.) According to PSCo's February 2021 Clean Energy Plan announcement,[1] Pawnee is scheduled to be converted to natural gas by 2028 and Comanche's Unit 3 is scheduled to be retired in 2040 but with a significant reduction in operating hours after 2030. The most likely alternate sources for this coal are the NARM, Antelope, Caballo and Cordero Rojo mines.

Based on expected production levels, these mines generally have 11 to over 20 years of reserves in their current coal leases and up to another 20 years in adjacent defined lease areas not yet under control. Mining companies generally avoid acquiring additional reserves sooner than necessary, due to the high lease bonuses required to lease the reserves. Beyond the specific reserves identified in this analysis, there are additional reserves in the PRB, as identified in the USGS *Coal Geology and Assessment of Coal Resources and Reserves in the Gillette Coal Field, Powder River Basin, Wyoming* published in 2015, that can extend coal production in the PRB by more than 80 years. Because of plant retirements and other factors, coal demand has been decreasing and the PRB mines generally have more production capacity than recent production levels.

The railroads serving the PRB have made significant investments in the rail transportation infrastructure and have sufficient capacity to meet expected demand.

Five PRB coal producers (Arch, Alpha, Peabody, Blackjewel and Cloud Peak) have gone through bankruptcy since 2015. Two of these companies have emerged from bankruptcy and three companies have been sold. With one exception, all the mines involved in these bankruptcies continued to operate

[1] Our Energy Future (xcelenergy.com)

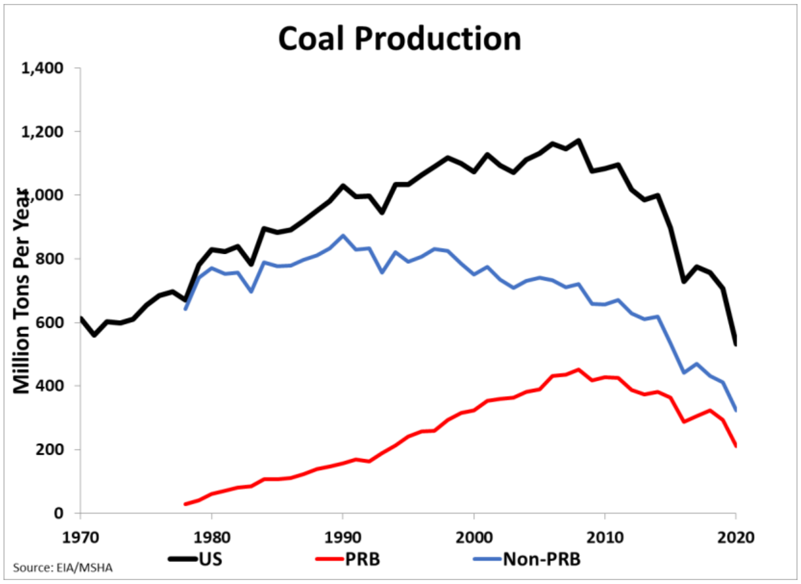
and ship coal through the bankruptcy proceedings. In the last case, the mines were returned to production after their sale to a new operator.

The Hayden and Craig plants purchased 4.5 MT in 2020 and are served by three local Colorado coal mines. With the announced retirement of Craig Units 1&2[2] and both the Hayden Units by 2028,[3] there appears to be sufficient production capacity and coal reserves at these three mines to supply the plants through their planned retirements.

US and Powder River Basin Coal Production and Demand

Between 1970 and 2008, annual coal production in the U.S. increased from 612.7 MT to 1,171.8 MT (Figure 1) as coal demand for electric power, which consumed an average of 88% of the coal produced between 2001 and 2019 (Figure 2), increased. In the late 1970s, production from the Powder River Basin (PRB) began to grow as mining and energy companies (ARCO, Mobil, Kerr McGee, Exxon, Peabody, Sunedco, and others) developed mines in this low production cost area to supply coal to the expanding electric power industry. Production in the PRB grew to a peak of 451.7 MT in 2008. While US and PRB production peaked in 2008, the combined production from other coal producing regions peaked in 1990. Since 2008, US and PRB has fallen to 532.5 and 210.0 MT, respectively.

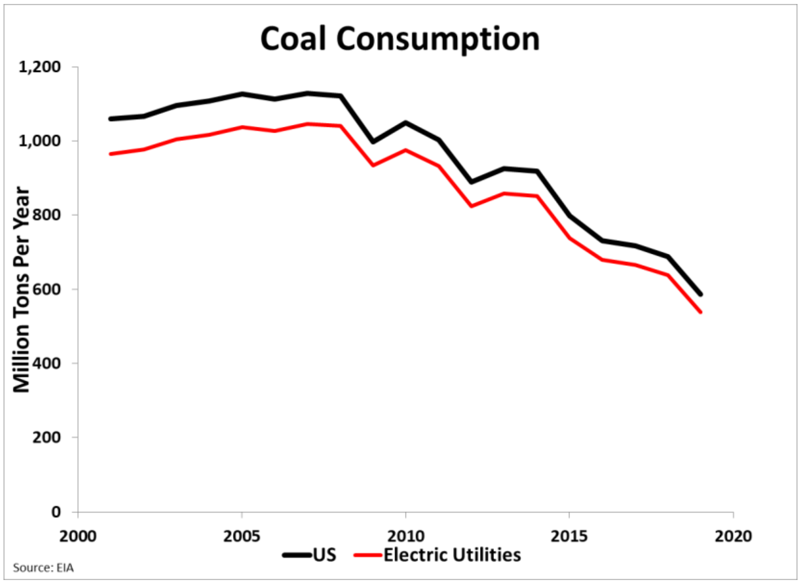
Figure 1 – US and PRB Coal Production 1970-2020



In 2001, 964.4 MT of coal were consumed by the U.S. electric power sector. This grew to a peak of 1,045.1 MT in 2007. Following the financial crash of 2008, the success of hydraulic fracturing ("fracking") in producing low-cost gas, state mandated renewable energy portfolios, and tax credits given to wind and solar energy projects, coal production for electric generation fell sharply to 538.6 MT in 2019.

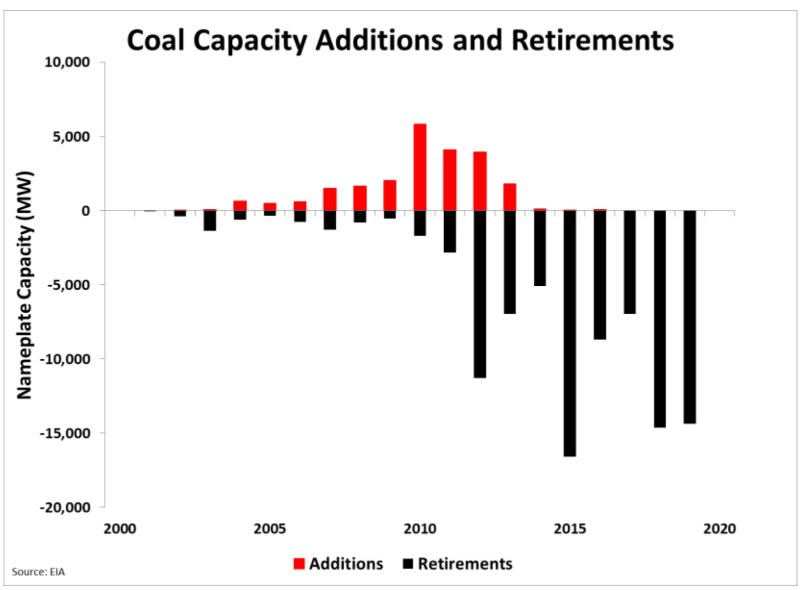
[2] Craig Station Unit 2 owners announce retirement date of Sept. 30, 2028 | Tri-State Generation and Transmission Association, Inc (tristategt.org)
[3] Xcel Energy - Xcel Energy announces retirement of Hayden power plant

Figure 2 – US Coal Consumption 2000-2019



Future demand will depend on numerous factors including changes in or additions to state mandated renewable energy portfolios, gas prices and aging power plants. US Energy Information Administration (EIA) data indicates that between 2001 and 2020, 95,131 megawatts (MW) (Nameplate Capacity) of coal fired generating capacity has been retired against 22,834 MW having been added, with almost 90% of the retirements made after 2011 (Figure 3).

Figure 3 – Coal Capacity Additions and Retirements 2001-2019



Going forward, EIA-860 data, supplemented with public announcements by various utilities, shows 126 units at 56 coal fired power plants, burning PRB coal, are expected to close or have closed between 2018 and 2045. These plants have a Nameplate Capacity of 50,348 MW and had coal receipts of approximately 64 MT in 2020, down from 117 MT in 2017 (Table 1).

Table 1 – Announced Coal Plant Retirements 2018-2045

			Nameplate		Planned				
		Generator	Capacity	Operating	Retirement	PRB Coal Receipts (plant total)			
Utility Name	**Plant Name**	**ID**	**(MW)**	**Year**	**Year**	**2017**	**2018**	**2019**	**2020**
ALLETE, Inc.	Clay Boswell	1	75.0	1958	2018	2,711,143	2,754,746	1,763,142	1,414,135
ALLETE, Inc.	Clay Boswell	2	75.0	1960	2018				
ALLETE, Inc.	Clay Boswell	3	364.5	1973					
ALLETE, Inc.	Clay Boswell	4	558.0	1980					
City of Colorado Springs - (CO)	Martin Drake	6	75.0	1968	2022	761,118	578,314	452,799	136,420
City of Colorado Springs - (CO)	Martin Drake	7	132.3	1974	2022				
City of Colorado Springs - (CO)	Ray D Nixon	1	207.0	1980	2029	755,923	583,527	834,890	784,384
City of San Antonio - (TX)	J T Deely	1	486.0	1977	2024	6,034,693			
City of San Antonio - (TX)	J T Deely	2	446.0	1978	2024				
Consumers Energy Co	Dan E Karn	1A	136.0	1959	2023	1,489,153	1,374,805	1,090,180	967,142
Consumers Energy Co	Dan E Karn	1B	136.0	1959	2023				
Consumers Energy Co	Dan E Karn	2A	136.0	1961	2023				
Consumers Energy Co	Dan E Karn	2B	136.0	1961	2023				
CP Crane Power, LLC	CP Crane Power, LLC	1	190.4	1961	2018	97,639	42,376		
CP Crane Power, LLC	CP Crane Power, LLC	2	209.4	1963	2018				
Dairyland Power Coop	Genoa	ST3	345.6	1969	2021	773,026	760,798	564,838	476,218
DTE Electric Company	River Rouge	3	358.1	1958	2022	420,297	377,615	188,904	
DTE Electric Company	Trenton Channel	9	535.5	1968	2022	1,054,400	775,748	799,439	138,161
Dynegy Kincaid Generation	Kincaid Generation LLC	1	659.5	1967	2027	3,064,564	2,843,057	2,241,129	1,000,056
Dynegy Kincaid Generation	Kincaid Generation LLC	2	659.5	1968	2027				
Dynegy Midwest Generation Inc	Baldwin Energy Complex	1	625.1	1970	2025	4,102,343	4,390,948	3,754,897	3,580,948
Dynegy Midwest Generation Inc	Baldwin Energy Complex	2	634.5	1973	2025				
Dynegy Midwest Generation Inc	Baldwin Energy Complex	3	634.5	1975	2025				
Dynegy Midwest Generation Inc	Havana	6	488.0	1,978	2019	1,806,210	1,536,488	940,128	
Dynegy Midwest Generation Inc	Hennepin Power Station	1	75.0	1,953	2019	1,001,513	967,086	476,961	
Dynegy Midwest Generation Inc	Hennepin Power Station	2	231.3	1,959	2019				
Electric Energy Inc	Joppa Steam	1	183.3	1953	2025	2,028,158	3,164,554	2,902,051	2,585,697
Electric Energy Inc	Joppa Steam	2	183.3	1953	2025				
Electric Energy Inc	Joppa Steam	3	183.3	1954	2025				
Electric Energy Inc	Joppa Steam	4	183.3	1954	2025				
Electric Energy Inc	Joppa Steam	5	183.3	1955	2025				
Electric Energy Inc	Joppa Steam	6	183.3	1955	2025				
Empire District Electric Co	Asbury	1	212.8	1970	2020	578,958	488,799	256,963	
FirstEnergy Generation Corp	FirstEnergy W H Sammis	1	190.4	1959	2020	212,365			
FirstEnergy Generation Corp	FirstEnergy W H Sammis	2	190.4	1960	2020				
FirstEnergy Generation Corp	FirstEnergy W H Sammis	3	190.4	1961	2020				
FirstEnergy Generation Corp	FirstEnergy W H Sammis	4	190.4	1962	2020				
FirstEnergy Generation Corp	FirstEnergy W H Sammis	5	334.0	1967	2020				
FirstEnergy Generation Corp	FirstEnergy W H Sammis	6	680.0	1969	2020				
FirstEnergy Generation Corp	FirstEnergy W H Sammis	7	680.0	1971	2020				
GenOn Power Midwest, LP	Avon Lake	9	680.0	1970	2020			59,647	85,351
Illinois Power Generating Co	Coffeen	1	388.9	1,965	2019	3,277,875	3,369,189	1,581,060	
Illinois Power Generating Co	Coffeen	2	616.5	1,972	2019				
Illinois Power Generating Co	Newton	1	617.4	1977	2027	1,802,464	1,873,819	1,960,081	1,805,318
Illinois Power Resources Generating LLC	Duck Creek	1	441.0	1,976	2019	1,097,497	1,542,972	1,115,413	
Illinois Power Resources Generating LLC	E D Edwards	2	280.5	1968	2022	1,890,610	1,843,442	1,900,477	1,932,584
Illinois Power Resources Generating LLC	E D Edwards	3	363.8	1972	2022				
Interstate Power and Light Co	Burlington (IA)	1	212.0	1968	2021	590,235	737,027	626,644	731,593
Interstate Power and Light Co	Prairie Creek	1	14.6	1997	2025	401,688	339,884	298,003	302,343
Interstate Power and Light Co	Prairie Creek	3	50.0	1958	2025				
Interstate Power and Light Co	Prairie Creek	4	148.8	1967					
Kansas City Power & Light Co	Montrose	2	188.0	1960	2018	227,718	107,057		
Kansas City Power & Light Co	Montrose	3	188.0	1964	2018				
KCP&L Greater Missouri Operations Co	Sibley	2	50.0	1962	2018	640,015	575,560		
KCP&L Greater Missouri Operations Co	Sibley	3	419.0	1969	2018				
Lansing Board of Water and Light	Eckert Station	4	80.0	1964	2020	260,000	275,987	26,367	3,492
Lansing Board of Water and Light	Eckert Station	5	80.0	1968	2020				
Lansing Board of Water and Light	Eckert Station	6	80.0	1970	2020				
Lansing Board of Water and Light	Erickson Station	1	154.7	1973	2025	545,248	459,452	379,571	
Luminant Generation Company LLC	Big Brown	1	593.4	1971	2018	4,169,285	47,477		
Luminant Generation Company LLC	Big Brown	2	593.4	1972	2018				
Luminant Generation Company LLC	Monticello	1	593.4	1974	2018	5,806,187			
Luminant Generation Company LLC	Monticello	2	593.4	1975	2018				
Luminant Generation Company LLC	Monticello	3	793.2	1995	2018				
Midwest Generations EME LLC	Will County	4	598.4	1963	2024	290,919	357,524	484,391	124,957
Northern Indiana Pub Serv Co	Michigan City	12	540.0	1974	2028	567,707	1,006,183	603,688	799,604
Northern Indiana Pub Serv Co	R M Schahfer	14	540.0	1976	2023	858,050	1,490,234	1,709,291	870,679
Northern Indiana Pub Serv Co	R M Schahfer	15	556.4	1979	2023				
Northern Indiana Pub Serv Co	R M Schahfer	17	423.5	1983	2023				
Northern Indiana Pub Serv Co	R M Schahfer	18	423.5	1986	2023				
Northern States Power Co - Minnesota	Allen S King	1	598.4	1958	2028	1,692,583	1,545,089	1,064,003	404,242

Utility Name	Plant Name	Generator ID	Nameplate Capacity (MW)	Operating Year	Planned Retirement Year	PRB Coal Receipts (plant total) 2017	2018	2019	2020
Northern States Power Co - Minnesota	Sherburne County	1	765.3	1977	2026	3,411,964	3,302,479	4,384,991	2,810,659
Northern States Power Co - Minnesota	Sherburne County	2	765.3	1976	2023				
Northern States Power Co - Minnesota	Sherburne County	3	938.7	1987	2030				
NRG Texas Power LLC	Limestone	1	893.0	1985	2030	4,896,019	5,753,908	5,789,317	3,821,684
NRG Texas Power LLC	Limestone	2	956.8	1986	2030				
NRG Texas Power LLC	W A Parish	5	734.1	1977	2045	8,534,612	9,487,882	8,792,160	6,487,724
NRG Texas Power LLC	W A Parish	6	734.1	1978	2045				
NRG Texas Power LLC	W A Parish	7	614.6	1980	2045				
NRG Texas Power LLC	W A Parish	8	654.0	1982	2045				
PacifiCorp	Dave Johnston	1	133.6	1959	2027	3,347,304	3,293,046	3,217,482	2,982,613
PacifiCorp	Dave Johnston	2	133.6	1961	2027				
PacifiCorp	Dave Johnston	3	255.0	1964	2027				
PacifiCorp	Dave Johnston	4	400.0	1972	2027				
Platte River Power Authority	Rawhide	1	293.6	1984	2030	1,253,133	1,027,140	1,101,816	1,049,651
Portland General Electric Co	Boardman	1	642.2	1980	2021	877,037	763,614	1,599,329	572,929
Public Service Co of Colorado	Comanche (CO)	1	382.5	1973	2022	5,460,224	5,670,093	4,913,015	2,573,817
Public Service Co of Colorado	Comanche (CO)	2	396.0	1975	2025				
Public Service Co of Colorado	Comanche (CO)	3	856.8	2010	2040				
Public Service Co of Colorado	Pawnee	1	552.3	1981	2028	2,331,034	2,137,789	1,738,878	2,063,349
Public Service Co of Oklahoma	Oklaunion	1	720.0	1986	2020	719,467	2,188,366	1,473,698	509,617
Salt River Project	Coronado	1	410.9	1979	2032	2,153,505	1,583,810	1,756,267	1,544,927
Salt River Project	Coronado	2	410.9	1980	2032				
Southwestern Public Service Co	Harrington	1	360.0	1976	2025	2,607,665	2,812,367	2,360,262	1,776,631
Southwestern Public Service Co	Harrington	2	360.0	1978	2025				
Southwestern Public Service Co	Harrington	3	360.0	1980	2025				
Southwestern Public Service Co	Tolk	1	567.9	1982	2037	2,842,987	2,061,403	1,671,184	1,083,167
Southwestern Public Service Co	Tolk	2	567.9	1985	2037				
Texas Municipal Power Agency	Gibbons Creek	1	453.5	1983	2023	520,733	405,141		
TransAlta Centralia Gen LLC	Transalta Centralia Generation	1	729.9	1972	2020	1,113,471	1,053,918	2,278,255	1,548,959
TransAlta Centralia Gen LLC	Transalta Centralia Generation	2	729.9	1973	2025				
Union Electric Co - (MO)	Labadie	1	573.7	1970	2036	9,413,306	8,828,013	7,641,075	9,642,532
Union Electric Co - (MO)	Labadie	2	573.7	1971	2036				
Union Electric Co - (MO)	Labadie	3	621.0	1972	2042				
Union Electric Co - (MO)	Labadie	4	621.0	1973	2042				
Union Electric Co - (MO)	Meramec	3	289.0	1959	2022	474,920	910,207	299,888	
Union Electric Co - (MO)	Meramec	4	359.0	1961	2022				
Union Electric Co - (MO)	Rush Island	1	621.0	1976	2039	5,032,159	4,430,204	3,482,385	3,777,191
Union Electric Co - (MO)	Rush Island	2	621.0	1977	2039				
Union Electric Co - (MO)	Sioux	1	549.7	1967	2028	2,144,990	2,604,901	1,875,932	1,186,802
Union Electric Co - (MO)	Sioux	2	549.7	1968	2028				
Wisconsin Electric Power Co	Pleasant Prairie	1	616.6	1980	2018	3,066,407	664,663		
Wisconsin Electric Power Co	Pleasant Prairie	2	616.6	1985	2018				
Wisconsin Electric Power Co	Presque Isle	5	90.0	1,974	2019	585,031	318,830		
Wisconsin Electric Power Co	Presque Isle	6	90.0	1,975	2019				
Wisconsin Electric Power Co	Presque Isle	7	90.0	1,978	2019				
Wisconsin Electric Power Co	Presque Isle	8	90.0	1,978	2019				
Wisconsin Electric Power Co	Presque Isle	9	90.0	1,979	2019				
Wisconsin Electric Power Co	South Oak Creek	5	299.2	1959	2024	2,776,961	2,925,628	2,214,050	1,720,621
Wisconsin Electric Power Co	South Oak Creek	6	299.2	1961	2024				
Wisconsin Electric Power Co	South Oak Creek	7	317.6	1965	2024				
Wisconsin Electric Power Co	South Oak Creek	8	324.0	1967	2024				
Wisconsin Power & Light Co	Edgewater	4	351.0	1969	2018	2,354,509	1,861,154	987,771	679,904
Wisconsin Power & Light Co	Edgewater	5	413.7	1985	2022				
Wisconsin Public Service Corp	Pulliam	7	81.6	1958	2018	330,832	51,872		
Wisconsin Public Service Corp	Pulliam	8	149.6	1964	2018				
		126	50,347.9			117,257,854	100,346,185	85,652,712	63,976,099

Source: EIA 860 - Plant name, Planned Retirement Year and Nameplate Capacity
Public announcements by various utilities
EIA 923 – Fuel Receipts

US Energy Information Administration Annual Energy Outlook 2020

The EIA prepares an Annual Energy Outlook (AEO). The AEO provides a projection of electric power demand and fuel sources required to meet that demand. The AEO includes a Reference case plus side cases that test various assumptions included in the Reference case.

What is the AEO2020 Reference case?

- The AEO2020 Reference case represents EIA's best assessment of how U.S. and world energy markets will operate through 2050, based on key assumptions intended to provide a base for exploring long-term trends.
- The AEO2020 Reference case should be interpreted as a reasonable baseline case that can be compared with the cases that include alternative assumptions.
- EIA based the economic and demographic trends reflected in the Reference case on the current views of leading economic forecasters and demographers. For example, the Reference case projection assumes improvement in known energy production, delivery, and consumption technologies.
- The Reference case generally assumes that current laws and regulations that affect the energy sector, including laws that have end dates, are unchanged throughout the projection period. This assumption makes it possible for us to use the Reference case as a benchmark to compare policy-based modeling.
- The potential effects of proposed legislation, regulations, or standards are not included in the AEO2020 cases.

Source: EIA Annual Energy Outlook 2020

This report does not include an analysis of the AEO or the accuracy thereof but finds the Reference case to be a convenient tool to assess the life of remaining reserves in the PRB. This assessment requires assumptions on future demand and the distribution of that demand between the mines in the PRB.

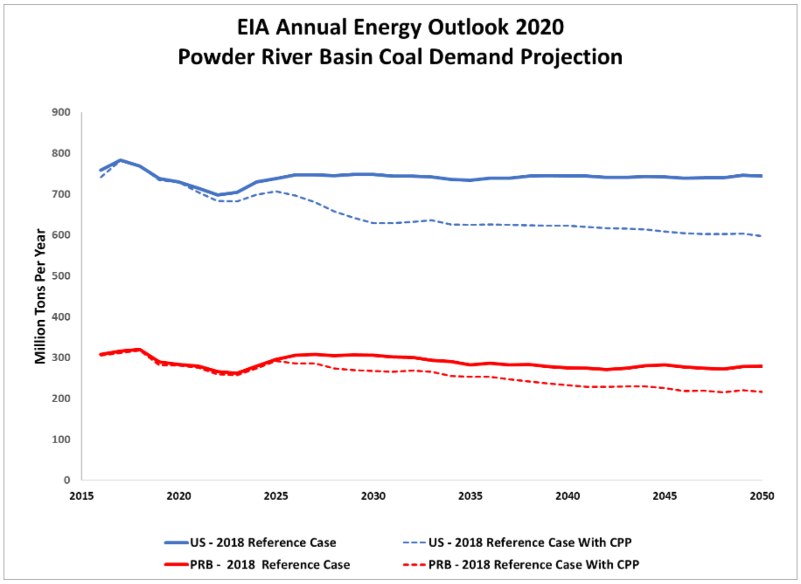
Figure 4 shows the future demand, as projected by the AEO Reference Case plus the Reference Case with the Clean Power Plan (CPP) for the US and the PRB. Note that the AEO projects falling demand for PRB coal through 2023 as demand falls from 320 MT in 2018 to 261 MT in 2023 before it rises to 308 MT in 2027. The AEO attributes changing demand for coal as follows:

—as capacity factors increase for the more efficient coal-fired units that remain in service

- In addition to decreases as a result of competitively priced natural gas and increasing renewables generation, coal-fired generating capacity decreases by 109 GW (or 46%) between 2019 and 2025 to comply with the Affordable Clean Energy (ACE) rule before leveling off near 127 GW in the AEO2020 Reference case by 2050.
- Average capacity factors for coal-fired generating units improve over time as less-efficient units are retired, as heat rates in the remaining coal fleet improve to comply with the ACE rule, and as natural gas prices increase
- Between 2019 and 2025, coal-fired generation decreases by 26% in the Reference case while natural gas prices increase. By 2030, the utilization rate of the remaining coal-fired capacity returns to 65%, which is slightly less than in the early 2000s. In the High Oil and Gas Supply case, coal-fired generation decreases by 42% between 2019 and 2025, and lower natural gas prices limit the utilization rate of the coal fleet to about 60% in 2030.
- Higher natural gas prices in the Low Oil and Gas Supply case slow the pace of coal power plant retirements by about 23 GW through 2025 compared with the Reference case. The Low Oil and Gas Supply case has 155 GW of coal-fired capacity still in service in 2050. Conversely, lower natural gas prices in the High Oil and Gas Supply case increase coal-fired power plant retirements by 28 GW in 2025, and 96 GW of remaining coal-fired capacity remains by 2050.

Source: EIA Annual Energy Outlook 2020

Figure 4 EIA Annual Energy Outlook 2020, PRB Coal Demand Projection



In light of 2017 -2020 production as well as announced retirements described above, a projected drop in production through 2023 is reasonable although 2020 production was well below the AEO projection. An 18% increase between 2023 and 2027 is considered unlikely. The AEO projects that most electric capacity retirements occur by 2025, and they will taper off in the later years of the projection period. The AEO assumes that the remaining fleet of coal fired power plants will continue to operate through 2050. This is considered unlikely as a cursory review of EIA-860 data indicates there may be over 62,000 MW of nameplate capacity at US coal fired power plants, that received almost 124 MT of coal in 2020, will have been in operation 50+ years by 2050.

In summary, while the author has not performed an analysis of the AEO, it is the author's opinion that the AEO Reference case overstates the future demand for PRB coal.

A final point related to the AEO; the EIA recognizes that there are adequate coal reserves in the PRB to meet their demand projections.

NOTE: While analysis of the CPP and Affordable Clean Energy Plan (ACE) is outside of the scope of this report, on January 19, 2021 a federal appellate court ruled against ACE. After the ruling, the Environmental Protection Agency (EPA) filed an unopposed motion to partially stay the CCP to assure the CCP did not take effect while the EPA considered how to best regulate power plants' greenhouse gas emissions. As shown on Figure 4, the CPP was expected to reduce the demand for coal nationwide and in the PRB, extending the life of reserves at existing mines.

PRB Geology and Mining

Geology

The PRB covers an area roughly 300 miles north to south and 100 miles east to west. While there are several coalfields in the PRB, this analysis covers the Gillette Coalfield, the most prolific coalfield in the United States, which covers an area about 60 miles long that extends from just north of the town of Gillette, Wyoming to just south of the Campbell-Converse county line south of Gillette. While coal seam nomenclature has varied over the years, almost all the production from the Gillette Coalfield has come from the Roland and Wyodak-Anderson seams. The coal seam thickness at the mines in the coalfield vary from 25 feet to 100 feet. The coal seams outcrop on the east side of the coalfield. The depth of overburden over the coal increases as mining progresses to the west.

According to the 2015 USGS report entitled *Coal Geology and Assessment of Coal Resources and Reserves in the Gillette Coal Field, Powder River Basin, Wyoming* published in 2015, there are about 162 billion tons of recoverable Powder River Basin coal resources at a stripping ratio of 10:1 or less. The report shows that there are an estimated 25 billion tons in the Powder River Basin that are recoverable at current coal market prices. This represents almost 120 years of coal at 2020 production levels. If market prices increase, more of the Powder River Basin coal will be recoverable.

The mines can be divided into three groups: North Gillette, South Gillette and Wright area mines. The North Gillette mines are those mines north of the town of Gillette: Buckskin, Rawhide, Eagle Butte, Dry Fork and Wyodak. The South Gillette mines are a group of mines South of Gillette: Caballo, Belle Ayr, Cordero-Rojo and Coal Creek. The Wright area mines are at the south end of the coalfield, east and south of the town of Wright: Black Thunder, North Antelope Rochelle (NARM), and Antelope.

The North Gillette mines produce an 8,200 to 8,500 Btu.lb coal, South Gillette mines typically produce an 8,500 to 8,600 Btu/lb. product and the Wright area mines average around 8,800 to 9,000 Btu/lb.

Mining Technology

Mining methods vary from mine to mine, but operating mines use truck/shovel or a combination of truck/shovel and draglines operations for overburden removal. Truck/Shovel mines use a fleet of large electric shovels teamed with large rear-dump trucks with a payload capacity of 250 tons or more. After blasting, overburden is loaded into the trucks and transported to a site selected for dumping. Draglines are large pieces of mining equipment used to remove overburden above coal and place it in a previously mined pit, adjacent to the pit to be mined. Draglines in the PRB have bucket capacities ranging from 44 cubic yards to 164 yards.

Truck/shovel operations are more expensive in terms of cost per Bank Cubic Yards per Ton (BCYT) moved but are more flexible in their use and can move overburden from where it is excavated to its final disposal site in a single operation. Truck/Shovel fleets also tend to be less capital intensive.

Draglines have a lower cost per BCYT moved but are more capital intensive and are limited in how far they can move overburden. In most cases, in the PRB, overburden moved with a dragline must be handled more than once, increasing the cost of the dragline operation. In almost all cases in the PRB, truck/shovel fleets are used in conjunction with draglines, pre-stripping ahead of the dragline and reducing the amount of material the dragline must rehandle.

Coal loading and transportation is performed with a truck/shovel fleet like those used in overburden removal. The coal is moved from the pit to a truck dump where it is dumped into a coal hopper/crusher and moved to a rail loadout where it is loaded into unit trains for shipment to customers. In many cases, the dump site is being moved to a location close to the pit and then moved to the rail loadout on an overland conveyor. This reduces the number of trucks required to move the coal along with the number of drivers. It also tends to have a lower operating cost and is less susceptible to increases in the cost of diesel fuel.

As noted in the following Coal Revenue and Production Cost Trends section, stripping ratios have increased slowly over time and will continue to rise as mining continues. PRB mines have responded by implementing some, or all, of the following to control costs:

1) Converting to larger equipment,
2) Incorporating more dragline capacity,
3) Using cast blasting to move overburden,
4) Constructing overland conveyors to reduce truck haul distances,
5) Adding autonomous (remote operated) equipment such as dozers, and
6) Revising work schedules.

Transportation

With few exceptions all coal mined in the PRB is transported by rail. The two railroads serving the PRB are the Burlington Northern Santa Fe (BNSF) and the Union Pacific (UP). The BNSF is the sole carrier for the North Gillette mines while the South Gillette and Wright area mines are served by both the BNSF and UP on the Joint Line. BNSF serves all mines in the PRB, has access to its mainline through Gillette, Wyoming and has better access to markets in the northern U.S. The UP is limited to moving coal south out of the PRB to markets to the east, south, southeast and southwest. The BNSF and UP have made significant investments in the rail infrastructure to transport PRB coal to coal fired plants. Over 440 million tons of PRB coal was transported out of the PRB in 2008 and there appears to be plenty of rail transportation capacity for expected production levels.

Energy Industry Trends

Following the financial crash of 2008, the success of fracking in producing low-cost gas, state mandated renewable energy portfolios, and tax credits given to wind and solar energy projects, coal production for electric generation fell sharply. These conditions are expected to continue, dampening the demand for and production of coal.

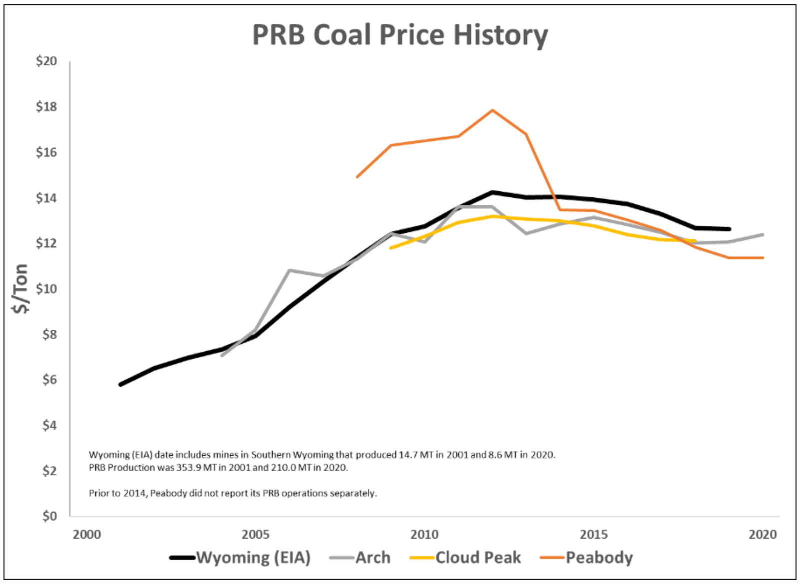
Political and regulatory actions can impact future energy trends. For example, halting the leasing of coal would have an impact on PRB coal production as existing leases are mined out, starting around 2032. Changes in environmental laws and regulations relating to power generation could also have the potential of impacting future coal production.

Coal Revenue and Production Cost Trends

Coal production costs have varied over the years as the mines have encountered varying mining conditions. Figure 5 provides historic sales prices for Wyoming coal. These prices include coal production from non-PRB mines in southern Wyoming which represent about 4% of the state's production. Because the PRB represents the vast majority of Wyoming coal production statewide price provides a reasonable approximation of the annual average PRB coal price trends. In addition to EIA's *Coal Annual* average coal price, the Figure provides annual prices for the three largest producers in the PRB: Arch, Cloud Peak and Peabody. The data for Arch, Cloud Peak and Peabody were collected from corporate annual reports. (Note that Arch reports were available going back to 2004, Cloud Peak was spun off from Rio Tinto in 2009 and Peabody did not separate its PRB operations from its other western

US mines until 2014. Cloud Peak filed for bankruptcy in May 2019 and was sold to Navajo Transitional Energy Company (NTEC) in October 2019.

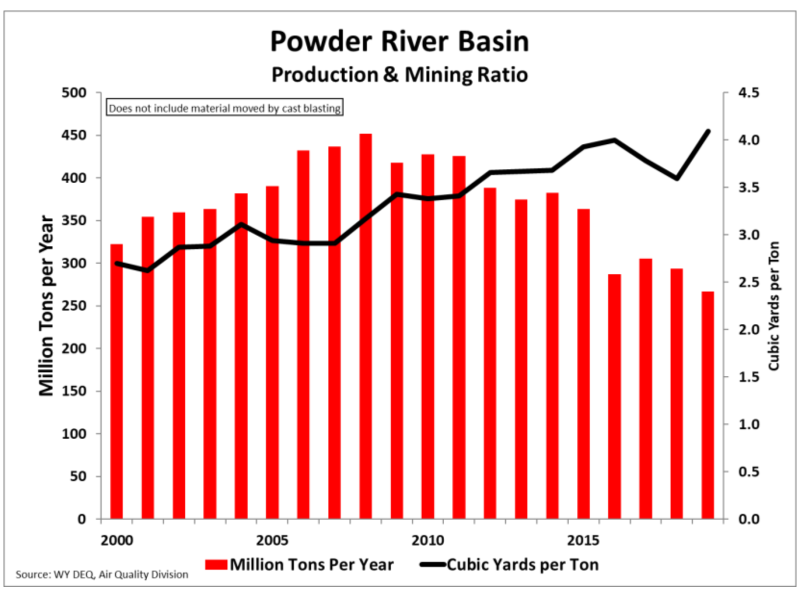
Figure 5 – PRB Coal Price History 2001-2020



Stripping Ratio

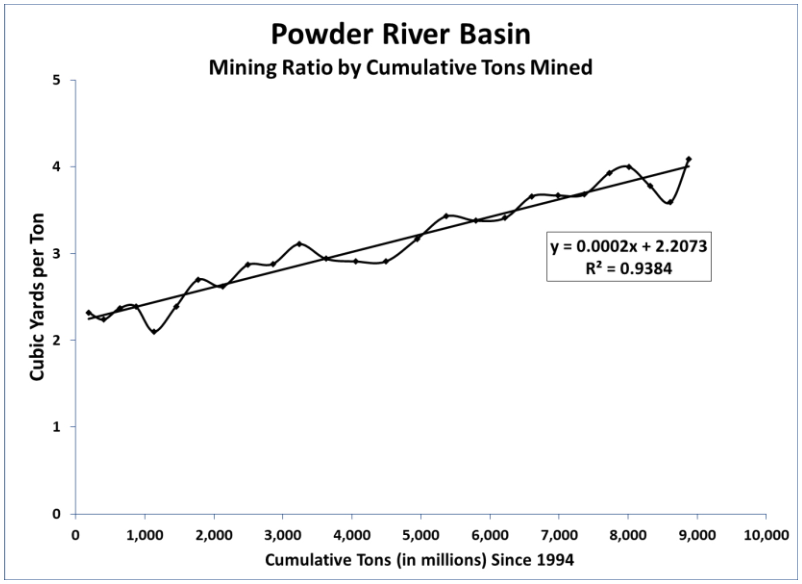
Figure 6 provides production and mining ratio trends in the PRB since 2001. The stripping ratio is a measure of the amount of overburden or waste material that must be moved for each ton of coal mined, is an indicator of mining costs and generally tracks increasing coal prices and, thus, increasing mining costs.

Figure 6 – PRB Production and Mining Ratios 2000-2019



Analysis of stripping ratio data shows the stripping ratio in the PRB has been increasing at a rate of 0.02 BCYT per 100 MT mined. Assuming this trend continues, the average stripping ratio will increase to approximately 5:1 BCYT in 2040. This relationship is illustrated on Figure 7.

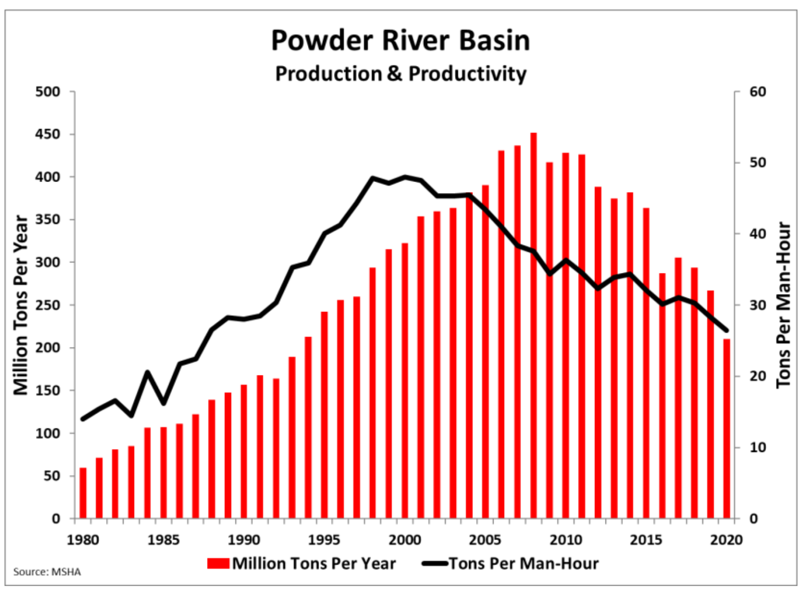
Figure 7-PRB Mining Ratio by Cumulative Tons Mined Since 1994



Labor Productivity

Figure 8 provides production and productivity trends since 2001. Like the stripping ratio, productivity is an indicator of mining costs. In this case there is an inverse relationship as declining productivity results in more employee hours, with increased labor costs, required to mine an equal amount of coal.

Figure 8 – PRB Labor Productivity 1980-2020



PRB Production Royalties, Taxes and Fees

Royalties, severance taxes, property taxes, reclamation fees and black-lung taxes are a significant part of the operating costs reported by coal producers. In aggregate, these costs account for approximately 30% of the coal sales price. Other costs that are not included below are bonus lease payments, which have exceeded $1.35/ton. Table 2 provides a breakdown of these costs:

Table 2 - PRB Production Royalties, Taxes and Fees

Federal	
Royalty	12.5% of price
Reclamation Tax	$0.28/ton
Black Lung Tax	4.4% of price with a $0.55/ton cap
Wyoming	
Severance Tax	8.5% of price (adjusted for coal hauling and processing) less royalties
Property Tax	6.7% of price (adjusted for coal hauling and processing) less royalties

Note that the Black Lung Tax was established in 1977 at $0.25 per ton for surface mines capped at 2% of the sales price. The rate was increased to $0.55 per ton capped at 4.4% through December 31, 2018. The rate dropped to the original $0.25 per ton/2% for calendar year 2019. Congress raised the rate back up to $0.55/4.4% for 2020 in the Further Consolidated Appropriations Act of 2020 signed in December 2019 and again for 2021 through Consolidated Appropriations Act for 2021 signed in December 2020. The Black Lung Tax is currently scheduled to drop back down to $0.25/2% on January 1, 2022. Similarly, the Federal Reclamation tax established in 1977 is due to expire on September 30, 2021. If the Black Lung Tax is allowed to remain at the reduced level or the Reclamation Fee is allowed to expire, it would significantly reduce the cost of producing PRB coal.

Projected PRB Reserves, Demand and Mine Life

PRB Coal Reserves

Estimating the life of mines requires an estimate of available reserves. For this analysis, PRB reserves are broken into three categories: current reserves held by operating companies, pending Lease-by-Applications (LBAs) and withdrawn LBAs. Additional reserves have been identified by the USGS that are not being considered in this analysis.

Current reserves held by Arch and Peabody are based on reserves reported in the company's annual reports. Other mine reserves are based on mine permit data.

Additional reserves may be acquired through the LBA process. The Bureau of Land Management (BLM) established the process where companies can nominate reserve blocks for leasing in a competitive bid process. Once a tract has been applied for, the BLM conducts an EIS on the tract and goes through a public hearing process. During the process, the BLM may modify the tract by adjusting the boundaries of the tract or splitting the tract into several tracts. Once the EIS process is completed a decision will be made to conduct a lease sale or reject the application. Before the sale takes place, the BLM prepares an estimate of the fair market value of the tract. The estimated fair market value is closely guarded and is used to ensure any bid on the tract meets or exceeds the fair market value of the tract. This process has resulted in 27 tracts, containing an estimated 7.9 billion tons of coal with lease bonus bids more than $5 billion, being leased since 1991. The LBA process has been suspended by the current administration while it is being evaluated by the BLM.

At present, there are three pending LBAs, containing 1.1 billion tons of coal, which may be offered for sale.

Properties impacted by the suspension include 7 LBA tracts, containing almost three billion tons of coal that were withdrawn from the process at the request of the applicant. The requests to withdraw the application are believed to be the result of expected high bonus bid requirements and a longer than initially expected time before the leases are required. (The most recent bids have been as high as $1.35 per ton.) It is possible for these tracts to be applied for in the future if the LBA process is resumed.

Table 3 provides a breakdown of reserves for each of the three categories being considered in this analysis.

Table 3 PRB Coal Reserves (End-of-year 2020)

Current Reserves		
Company	**Mine**	**Reserves (MT)**
Arch Coal	Black Thunder	698
	Coal Creek	90
ESM	Belle Ayr	238
	Eagle Butte	272
NTEC	Antelope	429
	Cordero Rojo	264
Peabody	Caballo	435
	NARM	1,544
	Rawhide	191
Western Energy	Dry Fork	224
Black Hills Energy	Wyodak	183
Kiewit Mining	Buckskin	111
		4,679
Pending LBAs		
	Applicant or	
Tract	**Succesor**	**Reserves (MT)**
North Hilight	Arch	468
Maysdorf II South	NTEC	234
West Antelope III	NTEC	441
		1,143
Withdrawn LBAs		
	Applicant or	
Tract	**Succesor**	**Reserves (MT)**
West Hilight Field	Arch	428
Hay Creek II	Kiewit Mining	148
Belle Ayr West	ESM	253
West Coal Creek	Arch	57
Antelope Ridge	Peabody	1,001
West Jacobs Ranch	NTEC	956
Maysdorf II	NTEC	149
		2,992
Total Reserves		8,814

PRB Coal Demand

A demand forecast has been prepared on a mine-by-mine basis for each of the producing mines in the PRB. The forecast assumes each mine will produce at 2020 levels less sales to plants identified as planned for retirement in Table 1. It is assumed that market shares will be maintained and sales to each of the plants identified in Table 1 will be reduced in the year following the unit retirement dates. This results in annual production falling from 210 MT in 2020 to 161 MT in 2040. Table 4 (provided as an attachment to this report) provides the results of this analysis on a mine-by-mine basis.

PRB Mine Life

This analysis estimates the remaining reserves for each of the PRB mines on an annual basis by reducing end-of-year reserves by annual production on a year-by-year basis. Current reserves will be mined first. When current reserves are depleted, additional reserves are added from the pending LBAs or the withdrawn LBAs as appropriate. As an example, Black Thunder's current reserves are forecast to be depleted in 2036 by which time the 468 MT North Hilight LBA will have been added to the mine's reserves. The North Hilight reserves will extend the mine life past 2040.

Based on this analysis, PRB may produce through 2040 with existing reserves and pending LBAs. Black Thunder will have to acquire the North Hilight tract to produce at projected rates past 2036 and Buckskin will have to acquire the Hay Creek II tract to operate past 2031.

Note: this analysis is not rendering an opinion that additional reserves will be acquired by any of the mines, only that additional reserves exist.

Financial Assessment of PSCo's Primary Coal Suppliers

Arch Resources

Arch is the US's second largest coal producer, selling 63 MT of coal in 2020. Coal is produced at eight mines in four of the country's coal producing regions: Appalachia, Illinois Basin, Powder River Basin and the Western Bituminous region.

Arch's strategic plan is to "pivot" from its "legacy" thermal assets towards its steel and metallurgical assets. As part of this plan Arch has contributed its share of the Viper mine, in Illinois, to Knight Hawk coal shedding mine closure liabilities totaling $21 million. Arch's remaining thermal assets are its PRB mines and the West Elk mine in Colorado. Arch's plan to reduce its operational footprint in the PRB is to accelerate the closure and final reclamation of the Coal Creek mine. The mine will ship on its existing contracts in 2021 before beginning final closure of the mine's active pit in 2022. To accomplish this, 40 employees plus equipment have been transferred from the Black Thunder mine to Coal Creek to accelerate ongoing reclamation. Black Thunder will continue to operate with cash flow being directed toward funding final reclamation of the mine. No plans for the West Elk mine have been announced. As this is being done, Arch is exploring strategic alternatives for these assets.

In June 2019, Arch and Peabody entered into an agreement to combine their PRB and Colorado assets in a joint venture. The joint venture was to be 66.5% owned by Peabody and 33.5% owned by Arch. Peabody was to be the operating partner. In September 2020, a US District Court upheld a Federal Trade Commission decision to block the joint venture.

In July 2015, Arch tried to restructure their highly leveraged balance sheet with an exchange offer. Arch was saddled with debt since its 2011 acquisition of International Coal Group and was suffering from a sharp drop in coal prices, stricter pollution controls, falling demand from China and increasing competition from natural gas. In January 2016, Arch filed for Chapter 11 bankruptcy protection with a plan to cut $4.5 billion in debt from its balance sheet during a prolonged downturn in the coal industry.

During its bankruptcy, Arch continued to operate and supply coal to its customers.

Arch exited bankruptcy in October 2016 and reported a profit of $238.5. million and an Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA) of $417.8 million in 2017. Arch reported a profit of $233.8 million with an EBITDA or $363.2 million. In 2020, the net profit dropped to -$344.6 million with an EBITDA of $23.7 million.

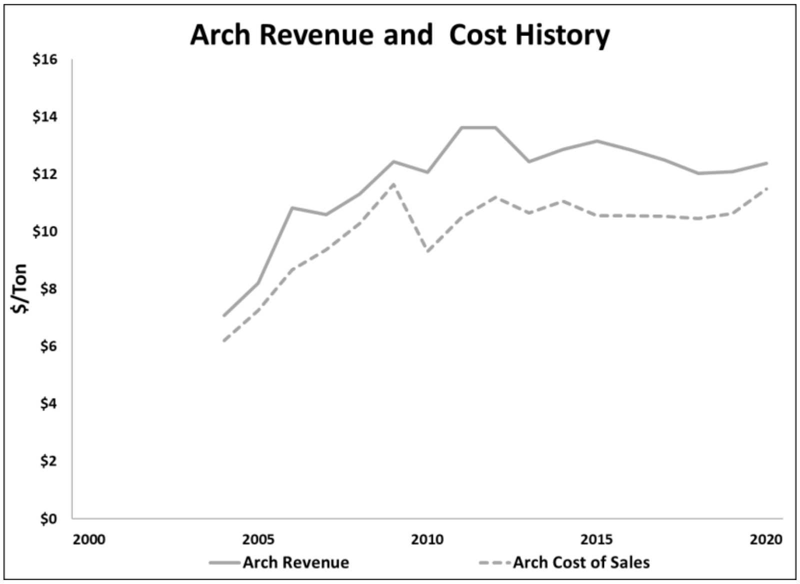
Prior to its bankruptcy, reclamation bonds at Arch's Wyoming mines were self-bonded. These bonds are now covered by surety bonds.

Arch is a long-time producer in the PRB, having purchased the Black Thunder and Coal Creek mines, along with other coal assets held by ARCO, for $1.14 billion, in 1998. At the time of the acquisition, annual production from the Black Thunder and Coal Creek mines was 42.7 and 7.0 MTY, respectively. In August 2004, Arch purchased Triton's North Rochelle and Buckskin mines for $364 million and production increased from 72.2 MT in 2004 to 87.6 MT in 2005. (The Buckskin mine was spun off to Kiewit Mining for $72.9 million.) In 2009, Arch bought Rio Tinto Energy America's Jacobs Ranch mine for $764 million and production increased from 81.1 MT in 2009 to 116.2 MT in 2010, making Black Thunder the largest coal mine in the world. When combined with the Coal Creek mine, Arch's total PRB production was 127.6 MT in 2010.

Arch's revenue and cost data by mining region has been collected from their annual reports from 2004 to 2020. Since Arch started reporting revenue and cost data on their PRB mines, revenues have increased from $7.07/ton in 2004 to $13.15 in 2015 before sliding back to $12.49/ton in 2017. At the same time, their production costs have increased from $6.21/ton in 2004 to $10.53 in 2017. The resulting operating margin has increased from $0.86/ton to $1.96/ton or from 12% to 16% of revenue.

In 2020, revenue was $12.38/ton and production costs were $11.48/ton resulting in an operating margin of $0.90/ton. See Figure 9.

Figure 9 – Arch Revenue and Cost History



Colowyo Coal Company, LP

Colowyo Coal Company LP is a wholly owned subsidiary of Tri-State Generation and Transmission Association, Inc. (Tri-State), a taxable wholesale electric power generation cooperative on a not-for-profit basis, that was incorporated in Colorado in 1952. The Association serves large portions of Colorado, Nebraska, New Mexico and Wyoming. In 2020, Tri-State's operating revenues were $1.2 billion.

Tri-State owns and operates the Colowyo mine, located near Meeker, Colorado, and supplies coal to the Craig Station. The mine was purchased from Rio Tinto in 2011. Tri-State owns 24% of units 1 and 2 at the Craig Station and 100% of unit 3. (PSCo owns 9.7% of units 1 and 2.)

Financial data is not available for the Colowyo mine.

Eagle Specialty Materials LLC (ESM)

ESM, a privately held company, acquired the Belle Ayr and Eagle Butte mines from the bankrupt Blackjewel LLC in October 2019. Blackjewel acquired the mines from Contura Energy and operated the mines under a mining license from Contura pending the transfer of permits and reclamation bonds. Blackjewel filed for bankruptcy before the bonds and permits were transferred and they are still held by Contura. ESM is now operating under a license agreement from Contura pending bond and permit transfers. Under the agreement between Contura and ESM, Contura paid ESM $81.3 million at closing and agreed to pay an additional $8.7 million into an escrow account to be used to make payment in respect of a federal royalty claim against Contura.

In late February 2021 an agreement, subject to bankruptcy court approval, between the Department of the Interior, the Blackjewel estate and ESM to settle claims on nearly $62 million worth of unpaid royalties incurred while Blackjewel was operating the Belle Ayr and Eagle Butte mines. This agreement could pave the way for transferring coal leases and mine permits to ESM.

In December 2017, Contura transferred the Belle Ayr and Eagle Butte mines to Blackjewel LLC, paying Blackjewel $21 million to take over the mines and assume reclamation and other liabilities. Blackjewel operated the mines under a license agreement with Contura pending the transfer of the mine permits to

Blackjewel. The transfer, however, was never completed. On July 1, 2019, Blackjewel filed for Chapter 11 reorganization bankruptcy. At the time of the filing, Blackjewel reported unsecured claims of more than $100 million related to the Belle Ayr and Eagle Butte mines. These claims included $60 million in unpaid federal royalties, $37 million in taxes due to Campbell County, Wyoming, and $12 million in taxes owed to Wyoming. Unlike other bankruptcies in the PRB the Belle Ayr and Eagle Butte mines did not continue operating as normal during the bankruptcy. Most workers were locked out and only limited shipments were made.

In a complicated process, Contura "repurchased" the mines it had sold two years earlier. When Contura announced that it did not have long-term plans for the mines, a new buyer was found. On October 18, 2019 Contura announced that it had closed a transaction with Eagle Specialty Materials (ESM), a subsidiary of FM Coal, in which ESM acquired the Belle Ayr and Eagle Butte mines. The deal appears to include an agreement with the Office of Surface Mining, Reclamation and Enforcement (OSM) that releases Contura from any liability created by ESM from the time ESM assumes operational responsibility for the permits until the permits are transferred to ESM. Contura has now paid ~$110 million to shed itself of the reclamation liability at the Belle Ayr and Eagle Butte mines and the permits still must be transferred.

Belle Ayr is the oldest of the modern-era mines in the PRB having been opened by AMAX Coal in 1972. Eagle Butte was opened by AMAX in 1978. These mines have changed hands multiple times over the years and were owned by Alpha Natural Resources (ANR) in 2015. Production at the two mines peaked at 51.6 MT in 2007 and has since fallen to 23.5 MT in 2020.

In August 2015, ANR filed for bankruptcy. The company had lost almost all its market value since 2011, after it bought Massey Energy Co. for about $7 billion leaving ANR deeply in debt as metallurgical coal prices plunged. In July ,2016, Contura Energy was formed by the creditors of ANR to acquire the core metallurgical and thermal coal assets, including ANR's PRB mines, in connection with its restructuring. Contura emerged from bankruptcy in June 2016 and began trading on the Over-The-Counter market (CNTE) in August 2017.

Blackjewel operated the Belle Ayr and Eagle Butte mines under a license agreement with Contura pending the transfer of the mine permits to Blackjewel. The mine permits were never transferred.

ESM is privately held, and financial data is not available.

Kiewit Mining Group

The Kiewit Mining Group is part of the employee owned, Kiewit Corporation a construction and engineering company that has been in business since 1864. Kiewit reported revenues of $10.4 billion in 2019. Kiewit owns and operates the Buckskin mine in the PRB, and contract mines the Walnut Creek and San Miguel mines in Texas. The company has a long history of coal mining and reclamation including the Rosebud mine near Hanna, Wyoming, and the Big Horn mine north of Sheridan, Wyoming.

Financial data is not available for the Kiewit Mining Group.

Navajo Transitional Energy Company LLC

NTEC, a privately held LLC owned by the Navajo Nation, purchased Cloud Peak's three PRB mines out of bankruptcy in November 2019 paying $15.7 million in cash plus a promissory note for $40 million. This made NTEC, which owns the Navajo mine in New Mexico, the third largest coal producer in the US. NTEC mines produced 43.5 million tons in 2020. NTEC is currently running the PRB mines pending transfer of the mine permits and the acceptance of reclamation bonds to replace bonds held by Cloud Peak.

Cloud Peak was the third largest producer of coal in the US and the only pure-play PRB coal company. The company is a spin-off of Rio Tinto's PRB operations. By 2008, Rio Tinto had acquired the Antelope, Cordero Rojo, Decker (50%), Jacobs Ranch and Spring Creek mines. Rio Tinto decided to sell these mines as a unit but was unable to find a buyer during the financial crash in 2008. The Jacobs Ranch mine was sold to Arch in 2009 and remainder of the mines were spun-off in the creation of Cloud Peak Energy. In 2014 Cloud Peak's interest in the Decker mine was sold to their partner Ambre (now Lighthouse).

In June 2012, Cloud Peak acquired Youngs Creek Mining Company, South of the Spring Creek mine, from Chevron and CONSOL for $300 million. Cloud Peak continued to work on permitting and developing Young's Creek but never began coal production despite significant investment.

In July 2012 Cloud Peak reached option agreements to lease and mine an estimated 1.4 billion tons of coal, in three deposits west of Spring Creek, on the Crow Indian Reservation. The Option and Exploration Agreements provide for exploration rights and exclusive options over an initial five-year term, with two extension periods through 2035. The agreement calls for payments the exercise of an option or options to lease, production royalties and coal production taxes to be paid to the Crow Tribe. These tax and royalty payments would range from 21% – 30% of the coal sales price. Big Metal was the Cloud Peak subsidiary holding the options. In June 2013, the U.S. Department of Interior, through the Bureau of Indian Affairs (BIA) approved the agreement.

Big Metal paid the Crow Tribe $2.25 million upon signing the Exploration Agreement and Option to Lease Agreement plus an additional $1.5 million upon BIA approval of these agreements, plus annual option payments thereafter during the initial option term that could bring total option payments to $10 million. Substantial multi-million-dollar payments would be made to the Tribe upon the exercise of a lease or leases.

In June 2014, Cloud Peak began exploratory drilling on the Crow lands and, on June 7, 2018, delivered notice to the Crow Tribe to exercise the Upper Youngs Creek coal lease option and extended the coal lease option for the Squirrel Creek and Tanner Creek project areas. In connection with the option exercise and option extension, Big Metal paid approximately $1.8 million to the Crow Tribe in June 2018. The coal lease will require completion of land access agreements and approval from the U.S. Department of Interior.

NTEC acquired these agreements as part of their purchase of Cloud Peak but their current status is unknown.

In 2018, a series of adverse events impacted Antelope. These included a delayed dragline move due to nesting golden eagles and severe thunderstorms that led to spoil pile slope stability problems. These events led to an unplanned drop in production from 28.5 MT in 2017 to 23.2 MT in 2018 with an accompanying drop in productivity from 26.4 TPMH to 20.1 TPMH. In addition to the impact on 2018 production, pre-stripping work planned for 2018 was deferred into 2019, increasing projected costs in 2019. On top of the issues at Antelope, there was a significant drop in export prices that impacted the Spring Creek mine. Finally, a weak market for 8,400 Btu coal led to reduced production at the Cordero mine. As a result of these events, Cloud Peak announced a "Strategic Alternatives Review" in November 2018.

The "Strategic Alternatives Review" concluded that a sale process in Chapter 11 bankruptcy was the best alternative for Cloud Peak and the company filed for Chapter 11 bankruptcy with the planned outcome being the sale of the company. In August 2019, the NTEC was the winning bidder for substantially all of Cloud Peak's assets in a competitive auction that took place as part of the Chapter 11 process. The key financial terms of NTEC's bid included a $15.7 million cash payment at closing, a $40 million second lien promissory note and a five year $0.15/ton royalty on future tons produced (royalties on Cordero production are limited to production more than 10 MTY). NTEC also agreed to assume pre- and post-petition tax liabilities and federal and stare royalty payments, all reclamation obligations, and up to $20 million in post-petition accounts payable. NTEC also agreed to carve-out certain real estate parcels, which Cloud Peak will market separately.

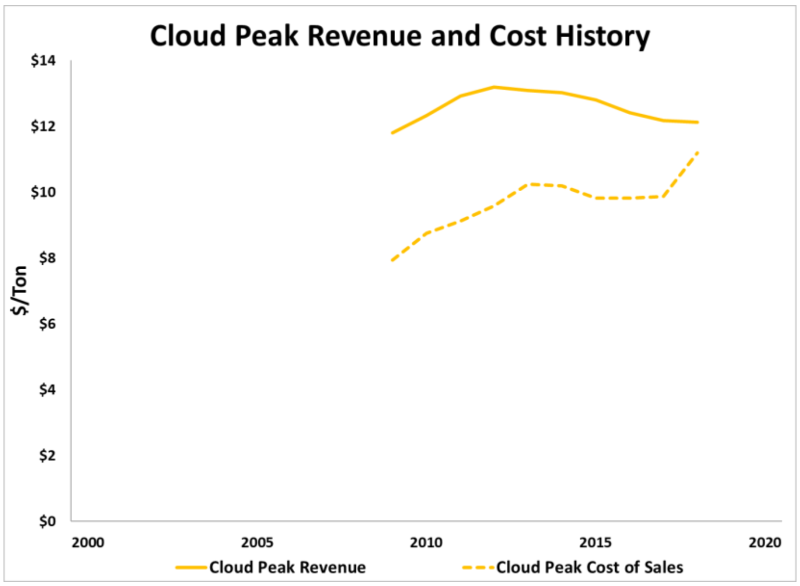
Cloud Peak's production from the Antelope and Cordero Rojo mines peaked at 76.5 MT in 2011 eventually falling to 29.6 MT in 2020. Cloud Peak also operated the Spring Creek mine, near Decker, Montana, which produced 19.1 MT in 2011, falling to 9.5 MT in 2020. Spring Creek exports thermal coal to the Asian market with annual volumes that have varied between 4.7 MT in 2011 and 2013 and 0.6 MT in 2017.

Since 2013, Cloud Peak had shown Operating Income (Loss) ranging from $131.8 million in 2014 to a loss of ($81.4) million in 2015. During the same time, they reported positive EBITDA in all years, ranging from $98.6 million in 2016 to $218.6 million in 2013.

All of Cloud Peak's reclamation bonding requirements are covered with surety bonds.

Cloud Peak began reporting revenue and cost data in 2009. From its first annual report for 2009 through 2018, Cloud Peaks annual revenue had fallen in a tight range of $11.79/ton to $13.19/ton with an average of $12.58/ton. Revenue was $12.11/ton in 2018. Production costs ranged from $7.94/ton in 2009 to $9.87/ton in 2017 and $11.19/ton in 2018. Note that 2018 costs were driven up by adverse conditions at Antelope. Since NTEC is a privately held company, more recent data is not available. Note that Cloud Peak includes their Spring Creek mine near Decker, Montana. See Figure 10.

Figure 10 – Cloud Peak Revenue and Cost History



Peabody Energy

Peabody Energy is the largest coal producer in the US, having sold 105.5 million tons of coal from 13 mines in six states in 2020. Peabody also sold 27.6 million tons of metallurgical and thermal coal from eight mines in Australia in 2020.

Peabody reported a net loss of -$185.1 million with an EBITDA of $883.0 million in 2019 and a loss of -$1,873.8 million and EBITDA of $258.8 million in 2020. The loss of -$1,873.8 million in 2020 included a $1,418.1 million a non-cash asset impairment charge related to the North Antelope Rochelle mine

In late 2020, Peabody reached an agreement with its 2022 bondholders, revolving credit lenders and surety bond providers to extend most of the company's near-term debt maturities to December 2024 and stabilize collateral requirements for the company's existing surety bond portfolio.

Peabody was the largest, publicly traded coal company in the world, when it filed for bankruptcy in April 2016.

Citing "unprecedented" industry pressures and a sharp decline in the price of coal, the company continued to operate while in bankruptcy, while working to reduce debt and improve cash flow. In addition to plummeting coal prices, the company mentioned weakness in China's economy, overproduction of domestic shale gas and ongoing regulatory challenges as reasons for its declining prospects.

Most of Peabody's woes were attributed to the ill-timed $5.2 billion McArthur Coal of Australia acquisition in late 2011. In 2010, MacArthur produced over 4 MT of metallurgical coal. At the time of the acquisition, Peabody management expected production to double to over 8 MT. This never occurred as demand dropped and the coal prices collapsed.

Peabody exited bankruptcy in April 2017, a year after its Chapter 11 filing. Most of its creditors supported its plan to cut over $5 billion of debt and raise capital from creditors with a $750 million private placement and a $750 million rights offering.

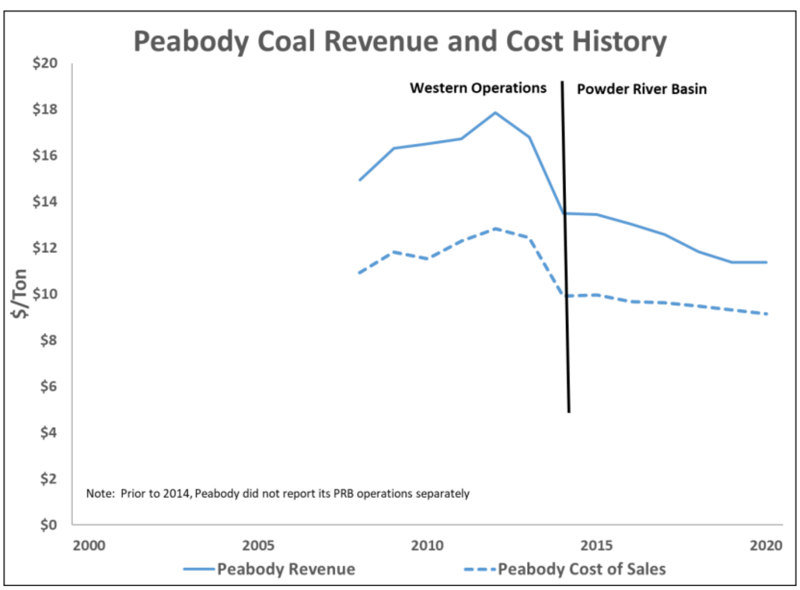
After emerging from bankruptcy Peabody reported a net income of $693 million from April 2 through December 31, 2017 and an EBITDA of $1,145.3 million for the same period.

Peabody operates the Caballo, North Antelope Rochelle (NARM) and Rawhide mines in the PRB. (NARM includes a reserve tract that may be referred to as School Creek or NARM North.) Peabody's PRB production peaked at 148 MT in 2011 before falling to 87.2 MT in 2020.

All of Peabody's PRB reclamation bonds are covered with surety bonds.

Peabody's revenue and cost data by mining region has been collected from Peabody's annual reports from 2008 to 2020. Prior to 2014, Peabody provided data on its Western Operation, which included the PRB plus its other mines in the western U.S. Since Peabody started reporting revenue and cost data on their PRB mines, revenues have declined from $13.49/ton in 2014 to $11.37/ton in 2020. During the same time, their production costs have remained stable, dropping from $9.92/ton to $9.14/ton. The resulting operating margin has fallen from $3.57/ton to $2.23/ton. See Figure 11.

Figure 11 – Peabody Revenue and Cost History

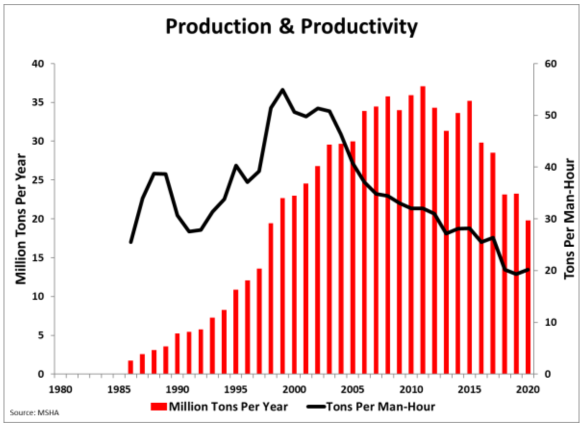


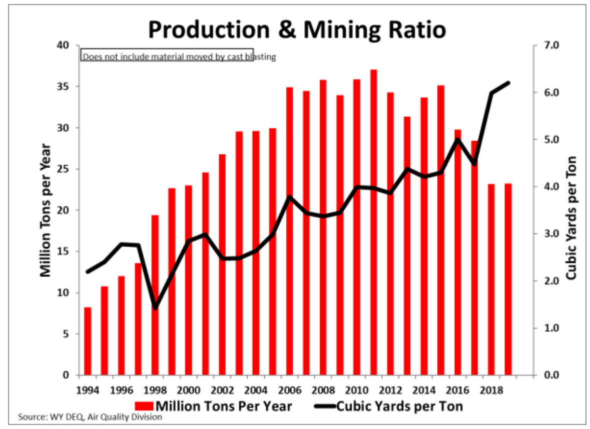
Viability Assessment of PSCo's Primary Coal Suppliers

Wyoming Powder River Basin

Antelope Mine

Cloud Peak's Antelope mine was opened in 1986 and is now owned by NTEC. It reached its peak production in 2011 when it produced 37.1 MT. In 2020, production was 19.8 MT. Labor productivity dropped from 55.0 TPMH in 1999 to 20.2 TPMH in 2020. The mining ratio has increased from a low of 1.4:1 BCYT in 1998 to 6.2:1 BCYT in 2020.





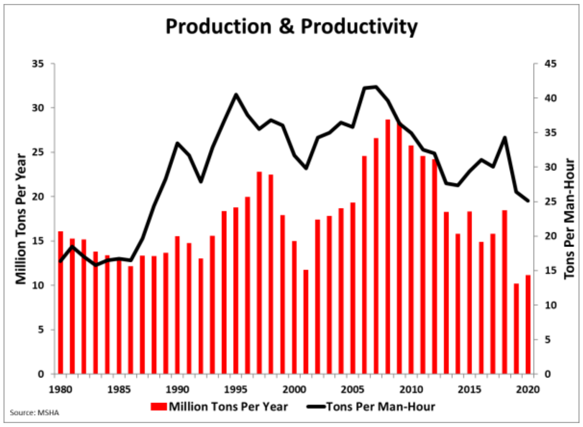
EIA-923 data indicates PSCo has purchased 10.6 MT of coal from the Antelope mine since 2008 with virtually all of it being delivered to the Comanche plant.

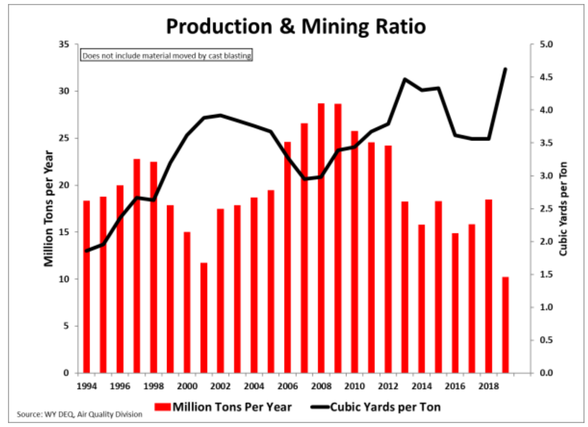
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Grand Total
							(1,000 tons)							
ANTELOPE COAL MINE														
Comanche	0.00	366.28	1,403.28	1,443.74	1,417.45	1,343.94	1,371.28	1,605.65	495.64	453.59	453.02	0.00	0.00	10,353.87
Pawnee	0.00	0.00	296.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	296.98
	0.00	366.28	1,700.27	1,443.74	1,417.45	1,343.94	1,371.28	1,605.65	495.64	453.59	453.02	0.00	0.00	10,650.85

Cloud Peak reported 489.7 MT of reserves at the end of 2017. Assuming Antelope continues to produce at 2020 levels, less tons delivered to plants with announced retirement dates between 2018 and 2043, these reserves will keep the mine operating past 2040. Cloud Peak has applied for the pending West Antelope III LBA, with an estimated 441 MT of reserves. If Cloud Peak acquires these reserves, the mine life will be extended past 2050.

Belle Ayr Mine

Having been opened by AMAX in 1972, Belle Ayr is the first of the modern era PRB mines. The mine has changed hands several times and is now owned by ESM. It reached its peak production in 2008 when it produced 28.7 MT. In 2020, production was 11.2 MT. Labor productivity peaked at 41.6 TPMH in 2007 before falling to 25.1 TPMH in 2020. The mining ratio has varied over the years as mining progressed through the mine, peaking at 4.5:1 BCYT in 2013 before increasing to 4.6:1 BCYT in 2020.





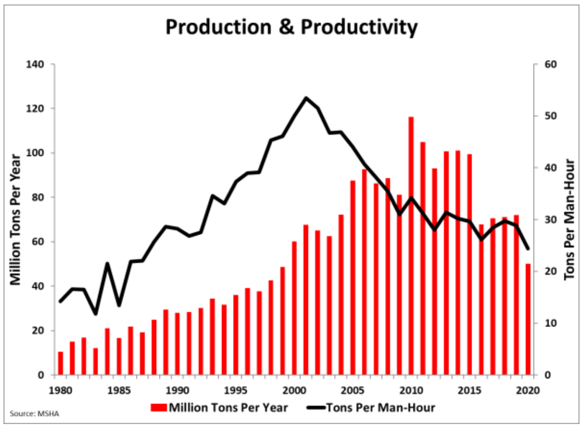
EIA-923 data indicates PSCo has purchased 31.8 MT of coal from the Belle Ayr mine since 2008 with virtually all of it being delivered to the Comanche plant. Deliveries to the Comanche plant were curtailed by outages caused by issues with the turbine and generator in Unit 3 in 2020.

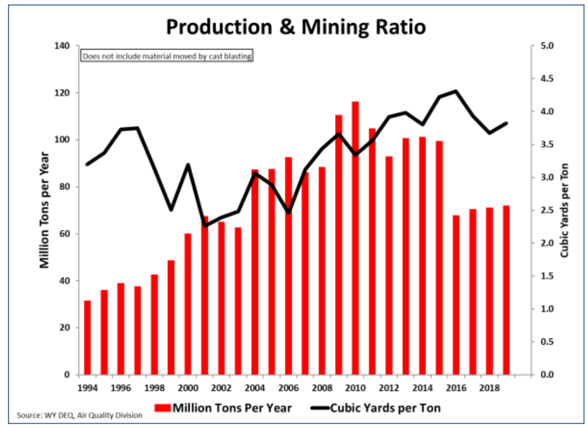
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Grand Total
							(1,000 tons)							
BELLE AYR MINE														
Arapahoe	0.00	0.00	0.00	0.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12
Comanche	2,602.59	2,889.47	2,346.42	2,530.11	2,645.00	2,472.16	2,542.79	2,318.66	2,911.48	2,851.84	2,595.63	1,609.20	1,101.50	31,416.84
Pawnee	14.64	14.27	0.00	111.38	14.13	14.13	0.00	0.00	0.00	0.00	0.00	0.00	168.87	337.41
	2,617.23	2,903.73	2,346.42	2,641.49	2,659.25	2,486.28	2,542.79	2,318.66	2,911.48	2,851.84	2,595.63	1,609.20	1,270.37	31,754.37

Available data from Contura's last annual report, prior to selling Belle Ayr and Eagle Butte to Blackjewel, indicates Belle Ayr reserves at the end of 2017 were 278.4 MT. Assuming Belle Ayr continues to produce at levels presented in Table 4, these reserves will keep the mine operating past 2040. In 2011, Alpha Natural Resources (an ESM predecessor) applied for the 253 MT, Belle Ayr West LBA. The application was later withdrawn for this tract but may be resubmitted in the future. If applied for and acquired, the reserves in this tract will extend the mine life past 2050.

Black Thunder Mine

The Black Thunder mine was opened by ARCO in 1977 and purchased by Arch in 1998. In addition to expansion of the original Black Thunder mine, the purchase of the adjoining North Rochelle and Jacobs Ranch mine from Triton Coal Co., a Shell Oil subsidiary, and Rio Tinto in 2004 and 2009 respectively, took Black Thunder's production up to 116 MT in 2010, making it the largest coal mine in the world. Production dropped to 99.5 MT in 2015. In 2016 Arch reduced the mine's production to 67.9 MT to, as they described it, "right-size" the mine. Production fell to 50.2 MT in 2020. Labor productivity peaked at 53.4 TPMH in 2001 and dropped to 24.8 TPMH in 2020. Black Thunder's mining ratio has varied over the years with a peak of 3.7:1 BCYT in 1996 and 1997 before falling to 2.3:1 BCYT in 2001. Since then, the ratio has trended upward reaching 4.3:1 BCYT in 2016 and 3.8:1 BCYT in 2020.





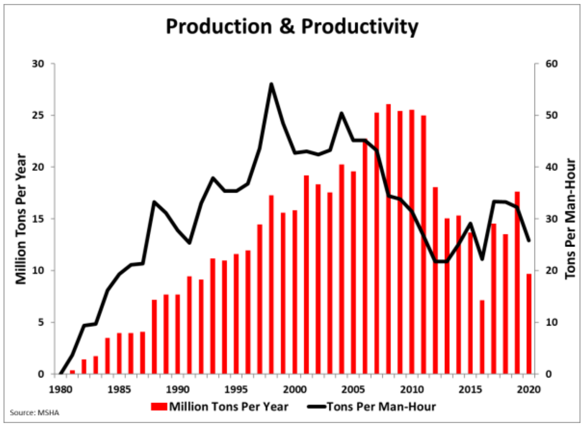
EIA-923 data indicates PSCo has purchased 18.3 MT of coal from the Black Thunder mine since 2008 with virtually all of it being delivered to the Comanche plant since 2014. Deliveries to the Comanche plant were curtailed by outages caused by issues with the turbine and generator in Unit 3 in 2020.

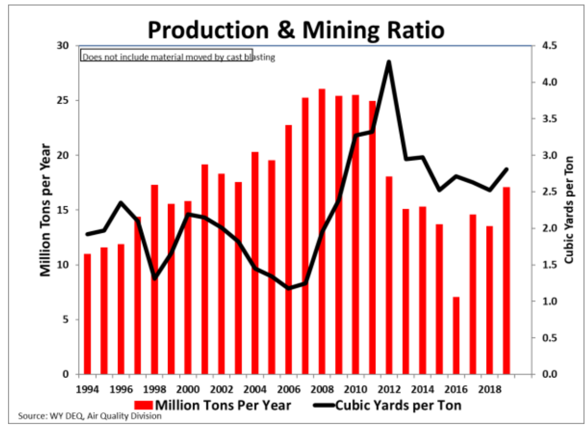
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Grand Total
							(1,000 tons)							
BLACK THUNDER														
Arapahoe	600.91	517.01	434.70	421.56	464.69	394.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2,833.19
Comanche	0.12	190.15	0.00	648.73	690.12	1,362.72	912.81	1,383.49	1,635.69	1,690.06	2,480.24	2,698.08	1,472.32	15,164.51
Pawnee	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.00	14.09	0.00	0.00	0.00	14.21
Valmont	75.11	197.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	272.12
	676.14	904.17	434.70	1,070.29	1,154.81	1,757.03	912.81	1,383.61	1,635.69	1,704.15	2,480.24	2,698.08	1,472.32	18,284.03

Arch reported Black Thunder's reserves were 698 MT at the end of 2020. Assuming Black Thunder produces at the levels presented in Table 4, these reserves will keep the mine operating until 2036. If Black Thunder acquires the adjacent 468 MT, North Hilight LBA the mine life will be extended past 2050. An additional 969 MT of reserves have been identified in the West Jacobs Ranch tract which was applied for in 2006. The application was withdrawn in 2014 but may be reapplied for if the BLM coal leasing program is resumed.

Buckskin Mine

The Buckskin mine was opened by Triton Coal Company, a Shell Oil subsidiary, in 1980. After passing through several hands, it was purchased, along with the North Rochelle mine and other assets, by Arch in 2004. It was promptly sold to Kiewit. Production peaked at 26.1 MT in 2008. Production fell to 18.1 MT in 2012, as Buckskin mined through a "geologic anomaly", and took another plunge to 7.1 MT in 2016 before recovering to 14.5 MT in 2017. Buckskin production jumped to 17.6 MT in 2019 when Buckskin sold coal to several Blackjewel customers that needed to replace coal lost due to the Belle Ayr and Eagle Butte mine closures. Production fell to 9.7 MT in 2020. Labor productivity peaked at 56.0 TPMH in 1998 and dropped to 21.7 TPMH in 2012 and 2013. By 2017, productivity recovered to 33.4 TPMH before falling to 25.8 in 2020. The mining ratio hit an all-time high of 4.3:1 BCYT in 2012, again, associated with the "geologic anomaly" before dropping to 2.5:1 BCYT in 2015. In 2019, the mining ratio was 2.8:1 BCYT.





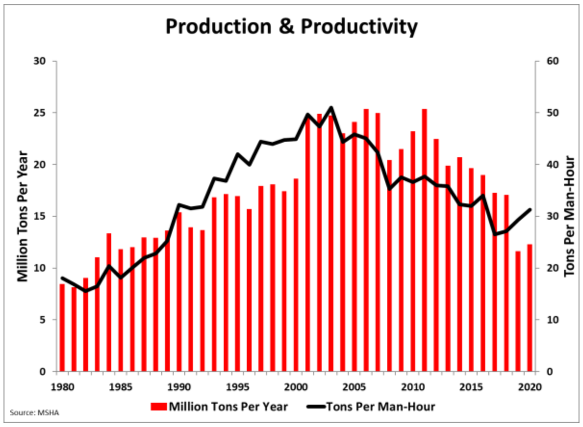
EIA-923 data indicates PSCo has purchased 10.4 MT of coal from the Buckskin mine since 2008 with virtually all of it being delivered to the Pawnee plant.

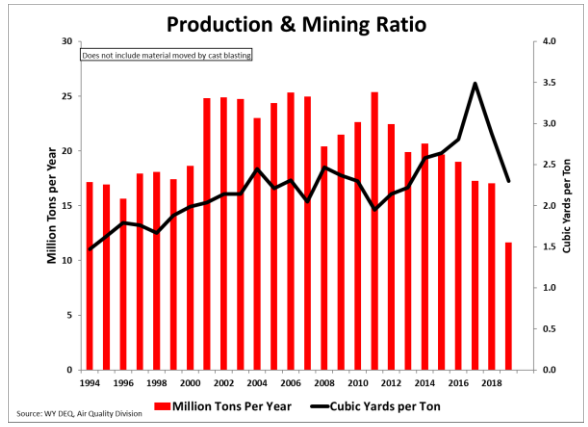
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Grand Total
							(1,000 tons)							
BUCKSKIN MINE														
Comanche	0.00	0.00	0.00	0.00	169.07	0.22	0.12	0.12	0.57	0.22	0.00	0.00	0.00	170.31
Pawnee	0.00	0.00	212.21	0.00	931.03	1,123.98	963.96	1,335.51	780.25	1,264.65	1,172.72	1,446.98	977.96	10,209.24
	0.00	0.00	212.21	0.00	1,100.10	1,124.19	964.08	1,335.64	780.82	1,264.86	1,172.72	1,446.98	977.96	10,379.55

Being an employee-owned company, Kiewit does not report reserves at the Buckskin mine. However, analysis of the mine permit application filed with the Wyoming Department of Environmental Quality—Land Quality Division, and actual production over the last several years, Buckskin's reserves have been estimated at 111 MT at the end of 2020. Assuming Buckskin produces at the levels presented in Table 4, these reserves will keep the mine operating until 2031. An additional 148 MT of reserves have been identified in the Hay Creek II tract which was offered for sale in 2006 and resulted in an unsuccessful bid of $0.21/ton. The tract may be reapplied for in the future if the BLM coal leasing program is resumed. If applied for and acquired, the reserves in this tract may extend the mine life past 2040.

Eagle Butte Mine

The Eagle Butte mine was opened by AMAX Coal in 1978. The mine has changed hands several times and is now owned by ESM. Production at Eagle Butte peaked at 25.4 MT in both 2006 and 2011. Production fell to 12.3 MT in 2020. Labor productivity peaked at 51.10 TPMH in 2003 and dropped to 31.3 TPMH in 2020. In 2011, the mining ratio was 2.0:1. By 2017 it had risen to 3.5:1 before falling to 2.3:1 in 2019.





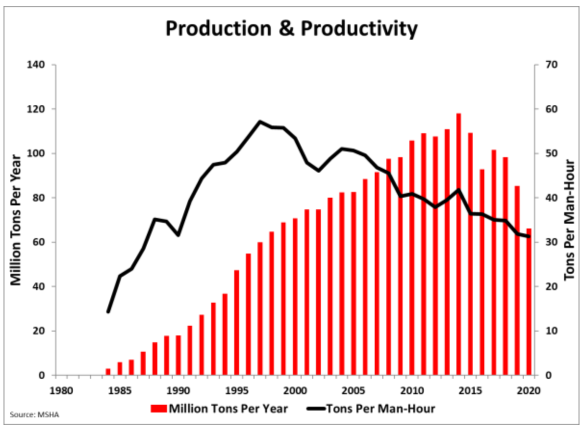
EIA-923 data indicates PSCo has purchased 13.9 MT of coal from the Eagle Butte mine since 2008 with virtually all of it being delivered to the Pawnee plant.

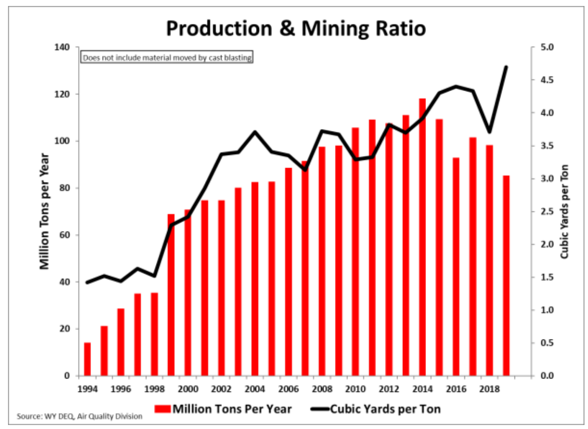
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Grand Total
							(1,000 tons)							
EAGLE BUTTE MINE														
Comanche	30.13	0.12	0.24	0.35	0.12	0.11	0.00	0.11	0.12	0.24	0.00	0.00	0.00	31.53
Pawnee	2,173.63	1,100.98	1,614.75	1,625.57	1,068.28	835.28	489.12	1,078.77	963.59	716.82	965.07	291.90	916.52	13,840.28
	2,203.76	1,101.10	1,614.98	1,625.92	1,068.40	835.39	489.12	1,078.88	963.71	717.05	965.07	291.90	916.52	13,871.81

Available data from Contura's last annual report prior to selling Belle Ayr and Eagle Butte to Blackjewel indicates that Eagle Butte's reserves at the end of 2020 were 272 MT. Assuming Eagle Butte continues to produce at levels presented in Table 4, these reserves will be depleted in 2043. Eagle Butte is hemmed in by the Rawhide mine to the north, the Dry Fork mine to the east, and the City of Gillette and its municipal airport on the south. To the west and northwest, it runs into bluffs which will lead to a significant increase in its mining ratio.

North Antelope Rochelle Mine

The NARM mine was originally opened by Peabody as two mines: North Antelope in 1984 and Rochelle in 1985. The mines were eventually merged into a single operation in 1999. In 2005. Peabody leased the West Roundup LBA from the BLM. In 2006, Arch and Peabody exchanged 60 MT blocks of coal with Peabody receiving 60 MT of reserves that Arch had acquired in its purchase of Triton Coal (North Rochelle and Buckskin mines) in 2004. Along with the reserves, Peabody acquired the surface facilities, loadout, now known as NARM-North, and rail associated with Triton's North Rochelle mine. Arch received 60 MT of coal from the West Roundup LBA. Peabody combined the coal reserves and other assets acquired in the exchange with other tracts held by Peabody as the School Creek property. In 2012, the School Creek property was combined with NARM under the same MSHA number. The first production from the property took place in 2013. Production at NARM peaked at 118 MT in 2014 before falling to 92.9 MT and 101.6 MT in 2016 and 2017, respectively. Production fell to 66.1 MT in 2020. Labor productivity peaked at 57.2 TPMH in 1997 and fell to 31.3 TPMH in 2020. In 2000, the mining ratio was 2.4:1 BCYT. By 2020 it had risen to 4.7:1 BCYT.





NARM reports an average coal specification of 8,800 Btu/lb. However, they ship a range of products with a small amount of 8,300 to 8,400 Btu/lb. coal to 9,000 Btu/lb. The coal is shipped through two loadouts: North Antelope Rochelle and NARM North (which ships coal from the School Creek property). It appears that the lower Btu product, less than 8,600 Btu/lb., is mined along the School Creek outcrop and shipped through the NARM North loadout.

PSCo has purchased ~775,000 tons of coal from NARM since 2008. This was a 2017/2018 Comanche test burn of 8,550 Btu coal, shipped out of NARM-N, and a 2019 test burn of 8,800 Btu coal.

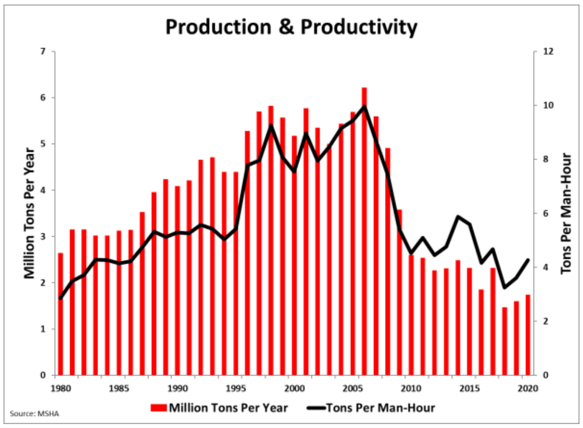
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Grand Total
							(1,000 tons)							
NORTH ANTELOPE ROCHELLE MINE														
Comanche	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28.20	141.20	605.74	0.00	775.13
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28.20	141.20	605.74	0.00	775.13

Peabody reported NARM's reserves were 1,544 MT at the end of 2020. Assuming NARM produces at the levels presented in Table 4, these reserves will keep the mine operating past 2040. An additional 1,001 MT of reserves have been identified in the Antelope Ridge tract which was applied for in 2011 by Peabody. The application was withdrawn in 2015 but can be reapplied for in the future if the BLM coal leasing program is resumed. If applied for and acquired, the reserves in this tract will extend the mine life well past 2050.

Colorado Uinta Basin

Colowyo Mine

The Colowyo mine was originally opened in 1977 by WR Grace. Kennecott, a subsidiary of Rio Tinto, purchased the mine in 1993. In 2006, Kennecott's parent company, Rio Tinto Energy America, eliminated use of the name Kennecott. Rio Tinto sold the mine to Tri-State in 2011. Production at Colowyo peaked at 6.2 MT in 2006. Production fell off to 2.6 MT in 2010 as it lost customers and 100% of its production began going to the Craig Station. In 2015, 2016 and 2017 the mine produced 2.3, 1.9 and 2.3 MT, respectively. Colowyo produced 1.7 MT in 2020. Labor productivity peaked at 10.0 TPMH in 2006 and has fallen to 4.3 TPMH in 2020. Based on mine permit documents, the mining ratio was expected to average 7.2:1 as mining moved into the Collom pit.



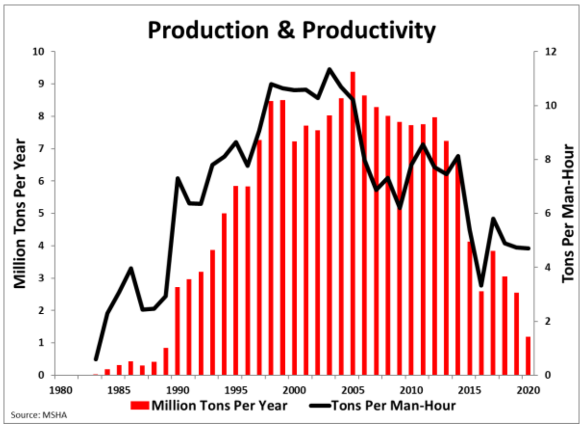
EIA-923 data indicates virtually all Colowyo's coal has gone to the Craig station since 2010. Tri-State owns 24% of units 1 and 2 at the Craig Station and 100% of unit 3. PSCo owns 9.7% of units 1 and 2 and all PSCo's coal supply for the Craig Station comes from the Colowyo mine in recent years.

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Grand Total
	(1,000 tons)													
COLOWYO MINE														
Public Service Co of Colorado														
Cherokee	11.19	106.15												117.34
Tri-State G & T Assn, Inc														
Craig	2,590.82	3,166.11	2,576.23	2,340.47	2,295.43	2,170.88	2,375.22	2,357.85	2,177.32	1,919.76	1,206.50	1,711.76	1,703.05	28,591.40
	2,602.01	3,272.26	2,576.23	2,340.47	2,295.43	2,170.88	2,375.22	2,357.85	2,177.32	1,919.76	1,206.50	1,711.76	1,703.05	28,708.74

Colowyo recently developed the Collom coal leases as they completed mining in their South Taylor pit which is now closed. Reserves in the Collom coal leases are estimated at 89 MT. South Taylor and Collom are part of a larger Logical Mining Unit containing 246 MT (including underground reserves). At a production rate of 2 MTY, the Collom leases have a remaining reserve life of over 40 years. Units 1 and 2 at the Craig Station will be retired by 2025 and 2028, respectively, and Unit 3 will be retired by 2030.

Foidel Creek/Twentymile

The Foidel Creek Mine (commonly referred to as Twentymile) is an underground, longwall mine that was opened in 1983 and purchased by Peabody in 2004. The mine's production peaked at 9.4 MT in 2005 and has since fallen as low as 1.2 MT in 2020. Labor productivity peaked at 11.3 TPMH in 2003, making it one of the largest and most productive underground mines in the country at that time. Since 2003, productivity has dropped as low as 3.3 TPMH in 2016 before rebounding to 5.8 TPMH in 2017. Productivity was 4.7 TPMH in 2020. Historically, the Foidel Creek mine produced coal in the Wadge seam. In 2015, work began to develop the lower Wolf Creek seam while mining in the Wadge Seam was completed. In 2016, the mine began producing in the Wolf Creek seam. The rebound in productivity in 2017 marks the completion of the move from the Wadge seam to the Wolf Creek seam.



EIA-923 data shows many customers Foidel Creek has had over the years. In addition to the customers reported on the EIA-923, Foidel Creek has served industrial markets and the export market. Over the last three years, as the mine's production has fallen, PSCo plants have taken the bulk of the tons reported in the EIA-923 report with the Hayden power plant being the largest single buyer. PSCo is the majority owner and operator of the Hayden Generating Station, owning about 75% of Unit 1 and 37.5% of Unit 2.

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Grand Total
							(1,000 tons)							
FOIDEL CREEK MINE														
Cherokee	1,414.93	1,563.38	1,142.48	1,571.14	1,432.50	1,227.62	1,460.53	965.47	741.12	436.48	0.00	0.00	0.00	11,955.64
Hayden	1,702.57	1,491.35	1,588.55	1,488.18	1,192.26	1,320.71	1,509.39	1,404.50	1,104.83	1,340.69	1,106.08	1,235.99	1,138.78	17,623.87
Valmont	285.09	195.06	272.54	147.90	165.92	244.52	229.91	450.69	393.17	55.23	0.00	0.00	0.00	2,440.02
	3,402.58	3,249.79	3,003.58	3,207.22	2,790.68	2,792.85	3,199.82	2,820.66	2,239.12	1,832.39	1,106.08	1,235.99	1,138.78	32,019.54

Peabody's 2020 Annual Report indicates 4 MT of reserves at the Twentymile mining complex at the end of 2019, down from 28 MT at the end of 2018. In May 2019, Peabody suspended work on an LBA for the Foidel Creek mine which would have added an estimated 4.68 million tons to the mine's reserves. At current production rates, Foidel Creek's reserves will be depleted in about three years. Peabody has a large additional reserve in the vicinity of the Foidel Creek mine, the Sage Creek mine. The Sage Creek mine has reported reserves of 105 MT and initial mine development work has been completed. With PSCo's announced plans to retire Hayden Unit 1 by 2027 and Unit 2 by 2028,[4] it is unlikely Peabody will invest in additional work developing these reserves unless other market opportunities appear for the mine.

[4] Xcel Energy - Xcel Energy announces retirement of Hayden power plant

Risk Factors

Bankruptcies

Five PRB producers have gone through bankruptcy proceedings: Arch (2015-2016), Alpha (2015-2016), Peabody (2016-2017), Blackjewel (2019) and Cloud Peak (2019). In three cases (Arch, Peabody and Alpha) the bankruptcy was brought on by excess debt triggered by investment in the metallurgical coal business when the price of metallurgical coal spiked to historically high prices. When the sales price and demand for metallurgical coal dropped along with the overall demand for coal, the companies were saddled with debt they could not service. The Cloud Peak bankruptcy was triggered by a series of adverse events including nesting golden eagles, severe thunderstorms, investments in Young's Creek and the Crow leases, and falling prices for exported thermal coal.

Arch exited bankruptcy in October 2016 with long-term debt reduced by $4.5 billion. In 2019, Arch reported a profit of $233.8. million and an EBITDA of $363.2 million. In 2020, Arch reported a loss of -$344.6 million and an EBITDA of $23.7 million. Arch is now restructuring the company through a phased strategic pivot away from its thermal assets to its steel and metallurgical assets.

After emerging from bankruptcy in 2017 Peabody's debt was reduced by over $5 billion. Peabody reported a net income of $693 million from April 2 through December 31, 2017 and an EBITDA of $1,145.3 million for the same period. In 2019 Peabody reported a loss of -$185.1 million and an EBITDA of $883.0 followed by a loss of -$1,873.8 and an EBITDA of $258.8 in 2020. $1,418.1 million of the 2020 loss is attributed to a non-cash asset impairment charge related to the North Antelope Rochelle mine.

In July 2016, Contura Energy was formed by the creditors of ANR to manage the core metallurgical and thermal coal assets, including ANR's PRB mines, in connection with its restructuring. Contura emerged from bankruptcy in June 2016 and began trading on the Over-The-Counter market (CNTE) in August 2017. In December 2017, Contura transferred the Belle Ayr and Eagle Butte mines to Blackjewel LLC, paying Blackjewel $21 million to take over the mines and assume reclamation and other liabilities. Blackjewel was privately held and financial data is not available for this company.

Blackjewel filed for bankruptcy in July 2019. The mines were sold to ESM in October 2019. ESM is a privately controlled LLC and financial data is not available for this company.

In November 2019, Cloud Peak's mines were sold to NTEC for $15.7 million in cash plus a promissory note for $40 million. NTEC is an LLC owned by the Navajo Nation and financial data is not available for this company

Except for the Belle Ayr and Eagle Butte mines which were idled by Blackjewel, all the PRB mines owned by these companies continued to operate without interruption during bankruptcy and both mines returned to production after bankruptcy.

Alternate Coal Sources

This analysis has focused on current reserves, reserves in pending LBAs, and other identified reserves associated with each of the mines operating in the PRB with a focus on mines currently selling coal to PSCo. The analysis has made certain assumptions regarding future production for each of the mines. The primary assumption is that there will be no power plant retirements other than those listed in Table 1. This is a conservative assumption because it does not consider the possibility of additional plant retirements which would extend the life of current reserves.

A review of Table 4 shows that Black Thunder and Buckskin will require additional reserves in 2036 and 2031, respectively. In 2020, these two mines supplied 2.5 MT to PSCo with 1.5 MT going to Comanche and 1.0 MT going to Pawnee. Additional reserves have been identified but will have to be acquired for these mines to continue producing past the listed dates. If the additional reserves are acquired, these mines will continue to operate past 2040.

If Black Thunder and Buckskin reserves are depleted earlier than projected, PSCo will have to look to other mines in the PRB to supply Comanche and Pawnee for their remaining operating years. However, this may not be an issue as according to PSCo's February 2021 Clean Energy Plan announcement,[5] Pawnee is scheduled to be converted to natural gas by 2028 and Comanche's Unit 3 is scheduled to be retired in 2040 but with a significant reduction in operating hours after 2030. In 2020, Comanche and Pawnee collectively received 4.6 MT. The most likely alternate sources for this coal are the NARM, Antelope, Belle Ayr, Caballo and Cordero Rojo mines.

In Colorado, there are two jointly owned plants supplied by the Colowyo, Trapper and Foidel Creek/Twentymile mines. These mines supplied the Hayden and Craig power plants with 4.5 MT in 2020. All units at these plants, at which PSCo has an ownership share, are scheduled to be retired by the end of 2028, except for Craig Unit 3 which is scheduled to operate until 2030. Colowyo and Trapper are the main suppliers to Craig but Foidel Creek/Twentymile has been burned at Craig as well. The Colowyo mine becomes the most likely alternate supplier of the Hayden plant if the Foidel Creek/Twentymile mine is not able to supply the plants' fuel requirements. Arch's West Elk coal has been burned at Hayden and is another possible supplier.

[5] Our Energy Future (xcelenergy.com)

Conclusions

Powder River Basin

US and PRB coal production peaked in 2008 when 1,172 MT were produced in the US and 451.7 MT were produced in the PRB. By 2020, production had fallen to 524 MT nationwide and 210 MT in the PRB due to the financial crash of 2008, the success of fracking in producing low-cost gas, state mandated renewable energy portfolios, and tax credits given to wind and solar energy projects, all of which resulted in the retirement of a number of power plants. Additional plant retirements have been announced that are expected to reduce PRB production to 161 MT by 2040. As coal burning units are retired, mine lives are extended because of the decreased demand.

In 2020, PSCo purchased 4.6 MT from four of the 12 PRB mines. These mines produced 83.4 MT in 2020, with production expected to fall to 60.9 MT in 2040. In 2035, when most of PSCo's coal fired units are expected to be retired, these mines are expected to produce 66.0 MT. Mines that produced coal for PSCo in 2020 currently hold reserves of 1,319 MT and have access to an additional 1,297 MT of identified but unleased coal. At projected production rates, the four mines currently supplying PSCo will deplete their currently held reserves in 11 to over 20 years. With the acquisition of additional identified reserves, the mine lives will be extended another 20 years.

In addition to the four mines that supplied PSCo in 2020, there are five additional mines that are potential suppliers for PSCo. These mines produced 116.8 MT in 2020 and are projected to produce 92.7 MT in 2040. They currently hold 1,150 MT of reserves and have access to an additional 2,741 MT of identified reserves. Beyond the specific reserves identified in this analysis, there are additional reserves in the PRB, as identified in the USGS *Coal Geology and Assessment of Coal Resources and Reserves in the Gillette Coal Field, Powder River Basin, Wyoming* published in 2015, that can extend coal production in the PRB by more than 80 years.

While all the major PRB producers have gone through bankruptcy, two have emerged from bankruptcy and continue to operate their mines and NTEC continues to operate the Cloud Peak mines. Belle Ayr and Eagle Butte continue to operate despite going through two bankruptcies. Except for the Blackjewel bankruptcy, all mines continued to operate while in bankruptcy and no shipments were missed.

Based on current production costs and the historic trends in stripping costs in the PRB, coal prices should remain competitive in the foreseeable future.

The railroads serving the PRB have made significant investments in the rail transportation infrastructure and have sufficient capacity to meet expected demand. Rail rates in recent rail transportation contract renewals in other regions have trended downward, lowering coal unit dispatch pricing.

Colorado

The Hayden and Craig power plants purchased 4.5 MT of coal from three Colorado mines in 2020. The three mines currently supplying the plants are Colowyo, Foidel Creek/Twentymile and Trapper. These mines produced a total of 5.0 MT in 2020. Trapper is captive to the Craig plant while Colowyo and Foidel Creek/Twentymile both have rail access to the Craig and Hayden plants. Reserves at Colowyo and Foidel Creek/Twentymile are 94 MT which is adequate to supply the two power plants for 25 years. In addition to the reserves at the two producing mines, Peabody has done mine development work on the Sage Creek project, near the Foidel Creek/Twentymile mine. Reserves at the Sage Creek project may exceed 100 MT. Additional coal may also be available from the West Elk mine in Colorado.

Table 4 – PRB Reserve Depletion

Table 4 - PRB Reserve Depletion

	Market Share	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Arch Resources																						
Black Thunder																						
2017 Production		50.2	48.0	48.0	47.2	46.1	45.0	44.2	43.4	42.7	41.1	39.9	39.5	37.9	37.9	37.9	37.9	37.9	36.8	33.9	33.3	33.3
Plant Retirements																						
Allen S King	0.8	0.3									0.3											
Clay Boswell		1.4																				
Comanche (CO)	0.6	1.5			0.3			0.4										0.8				
Coronado	0.2	0.5			0.1			0.1										0.3				
Dan E Karn	0.6	0.5				0.5																
Eckert Station		0.0																				
Edgewater	0.1	0.1			0.1																	
Genoa	1.0	0.5		0.5																		
Harrington	0.2	0.4						0.4														
Labadie	0.6	6.1																	2.9			
Limestone	0.2	0.9											0.9									
Michigan City	1.0	0.8									0.8											
Prairie Creek	0.2	0.0						0.0														
R M Schahfer	0.4	0.3		0.3																		
Ray D Nixon	0.5	0.4										0.4										
Rush Island	0.0	0.0																				
Sherburne County	0.8	2.1				0.7			0.7				0.8									
Sioux	0.1	0.1									0.1											
South Oak Creek	0.4	0.7					0.7															
Tolk	0.5	0.5																		0.5		
Trenton Channel	0.8	0.1			0.1																	
W A Parish	0.3	2.1																				
Plant Retirements Transferred From Coal Creek																						
Dave Johnson	0.5	1.6								1.6												
Edgewater	0.6	0.4			0.4																	
W A Parish	0.1	0.3																				
Future Production		50.2	48.0	47.2	46.1	45.0	44.2	43.4	42.7	41.1	39.9	39.5	37.9	37.9	37.9	37.9	37.9	36.8	33.9	33.3	33.3	33.3
Reserves (EOY)		698.0	650.0	602.0	554.8	508.6	463.7	419.4	376.1	333.4	292.2	252.3	212.8	174.9	137.1	99.2	61.4	491.1	454.3	420.4	387.1	353.7
Reserve Additions		West Jacobs Ranch-956 mmt																North Hilight LBA-467.6 mmt				
Coal Creek - Transfer market and retirements to Black Thunder																						
Production		2.1	2.0																			
Plant Retirements																						
Dave Johnson	0.5	1.6																				
Edgewater	0.6	0.4																				
W A Parish	0.1	0.3																				
Future Production		2.1	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reserves (EOY)		90.0	Reserves Abandoned																			
Reserve Additions		West Coal Creek-57 mmt																				

Table 4 - PRB Reserve Depletion

	Market Share	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Eagle Specialty Materials																						
Belle Ayr																						
Production		11.2	11.2	11.2	10.3	10.1	10.1	10.1	9.5	9.5	9.5	9.3	9.3	9.3	9.3	9.3	9.3	9.3	8.7	8.7	8.7	8.7
Plant Retirements																						
Baldwin Energy Complex	0.1	0.2						0.2														
Boardman	1.0	0.6		0.6																		
Burlington (IA)	0.4	0.3		0.3																		
Comanche (CO)	0.4	1.1			0.3			0.3										0.6				
Newton	0.0	0.0								0.0												
Pawnee	0.1	0.2									0.2											
Prairie Creek	0.2	0.1						0.0														
Rush Island	0.3	1.3																				1.3
Sioux	0.0	0.0									0.0											
Future Production		11.2	11.2	10.3	10.1	10.1	10.1	9.5	9.5	9.5	9.3	9.3	9.3	9.3	9.3	9.3	9.3	8.7	8.7	8.7	8.7	7.4
Reserves (EOY)		238.0	226.8	215.7	205.3	195.3	185.2	175.2	165.7	156.1	146.6	137.3	128.0	118.7	109.4	100.1	90.8	81.6	72.8	64.1	55.4	46.7
Reserve Additions		Belle Ayr West-253 mmt																				
Eagle Butte																						
Production		12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.2	12.2	12.2	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Plant Retirements																						
Baldwin Energy Complex	0.0	0.1						0.1														
Newton	0.0	0.0								0.0												
Pawnee	0.4	0.9									0.9											
Future Production		12.3	12.3	12.3	12.3	12.3	12.3	12.2	12.2	12.2	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Reserves (EOY)		272.0	259.7	247.4	235.1	222.8	210.5	198.2	185.9	173.7	161.5	150.2	138.9	127.6	116.2	104.9	93.6	82.3	71.0	59.7	48.4	37.0
Reserve Additions																						
Kiewit																						
Buckskin																						
Production		9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.3	9.3	9.3	8.3	8.3	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Plant Retirements																						
Baldwin Energy Complex	0.1	0.4						0.4														
Limestone	0.2	0.8											0.8									
Newton	0.0	0.0								0.0												
Pawnee	0.5	1.0									1.0											
W A Parish	0.4	2.6																				
Future Production		9.7	9.7	9.7	9.7	9.7	9.7	9.3	9.3	9.3	8.3	8.3	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Reserves (EOY)		111.0	101.3	91.6	81.9	72.2	62.5	52.8	43.5	34.1	24.8	16.5	156.2	148.7	141.2	133.7	126.2	118.7	111.3	103.8	96.3	88.8
Reserve Additions													Hay Creek II-148 mmt									

Table 4 - PRB Reserve Depletion

	Market Share	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Navajo Transitional Energy Company																						
Antelope																						
Production		19.8	19.8	19.8	19.8	19.8	19.8	19.6	19.5	19.5	19.2	18.2	18.2	17.1	17.1	16.1	16.1	16.1	16.1	15.4	15.4	15.4
Plant Retirements																						
Clay Boswell	0.2	0.2																				
Coronado	0.7	1.1													1.1							
Joppa Steam	0.0	0.0						0.0														
Labadie	0.1	1.3																	0.6			
Newton	0.2	0.4								0.4												
Prairie Creek	0.6	0.2						0.1														
Rawhide	1.0	1.0											1.0									
Rush Island	0.4	1.5																				1.5
Sioux	0.8	1.0									1.0											
South Oak Creek	0.1	0.2					0.2															
Trenton Channel	0.3	0.0			0.0																	
Future Production		19.8	19.8	19.8	19.8	19.8	19.6	19.5	19.5	19.2	18.2	18.2	17.1	17.1	16.1	16.1	16.1	16.1	15.4	15.4	15.4	13.9
Reserves (EOY)		429.0	409.2	389.4	369.6	349.8	330.0	310.4	290.9	271.4	252.2	234.1	215.9	198.8	181.7	165.6	149.6	133.5	117.5	102.0	86.6	71.1
Reserve Additions		West Antelope 3-441 mmt																				
Cordero																						
Production		9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8
Plant Retirements																						
Future Production		9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8
Reserves (EOY)		264.0	254.2	244.5	234.7	224.9	215.1	205.4	195.6	185.8	176.0	166.3	156.5	146.7	136.9	127.2	117.4	107.6	97.8	88.1	78.3	68.5
Peabody																						
Caballo																						
Production		11.6	11.6	11.6	11.6	11.6	11.6	11.6	10.7	10.7	10.4	10.4	10.4	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Plant Retirements																						
Baldwin Energy Complex	0.2	0.9						0.9														
Dave Johnston	0.1	0.4								0.4												
Limestone	0.0	0.1											0.1									
W A Parish	0.1	0.5																				
Future Production		11.6	11.6	11.6	11.6	11.6	11.6	10.7	10.7	10.4	10.4	10.4	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Reserves (EOY)		435.0	423.4	411.8	400.2	388.6	377.0	365.4	354.7	343.9	333.5	323.2	312.8	302.5	292.2	281.9	271.6	261.3	251.0	240.8	230.5	220.2
Reserve Additions																						

Table 4 - PRB Reserve Depletion

	Market Share	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Peabody Continued																						
NARM																						
Production		66.1	66.1	66.1	65.1	62.9	62.2	61.3	54.4	54.2	50.8	50.6	50.2	50.0	50.0	49.8	49.8	49.8	49.8	48.7	48.1	48.1
Plant Retirements																						
Allen S King	0.2	0.4									0.1											
Baldwin Energy Complex	0.8	2.9						2.9														
Burlington (IA)	0.6	0.4		0.4																		
Clay Boswell	0.3	0.4																				
Coronado	0.1	0.2													0.2							
Dan E Karn	0.5	0.4				0.4																
Dave Johnston	0.4	1.0								1.0												
E D Edwards	1.0	1.9			1.9																	
Edgewater	0.3	0.2			0.2																	
Harrington	0.8	1.4						1.4														
Joppa Steam	1.0	2.6						2.6														
Kincaid Generation LLC	1.0	1.0								1.0												
Labadie	0.2	2.3																	1.1			
Martin Drake	1.0	0.1			0.1																	
Newton	0.8	1.4								1.4												
Oklaunion	1.0	0.5		0.5																		
R M Schahfer	0.6	0.6		0.1																		
Ray D Nixon	0.5	0.4										0.4										
Rush Island	0.3	1.0																				1.0
Sherburne County	0.3	0.7				0.2			0.2				0.3									
Sioux	0.1	0.1									0.1											
South Oak Creek	0.5	0.8					0.8															
Tolk	0.5	0.5																		0.5		
Will County	1.0	0.1					0.1															
Future Production	-13.5	66.1	66.1	65.1	62.9	62.2	61.3	54.4	54.2	50.8	50.6	50.2	50.0	50.0	49.8	49.8	49.8	49.8	48.7	48.1	48.1	47.2
Reserves (EOY)		1,544.0	1,477.9	1,411.8	1,346.7	1,283.8	1,221.6	1,160.3	1,105.9	1,051.7	1,000.9	950.3	900.1	850.1	800.2	750.4	700.6	650.8	601.0	552.3	504.1	456.0
Reserve Additions	Antelope Ridge - 1001 mmt																					
Rawhide																						
Production		9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Plant Retirements																						
Limestone	0.5	2.0											2.0									
Newton	0.0	0.0								0.0												
Transalta Centralia Generation	1.0	1.5						1.5														
Future Production		9.5	9.5	9.5	9.5	9.5	9.5	7.9	9.5	9.5	9.5	9.5	7.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Reserves (EOY)		191.0	181.5	172.0	162.5	153.0	143.5	134.0	124.5	115.0	105.6	96.1	86.6	77.1	67.6	58.1	48.6	39.1	29.6	20.1	10.6	1.1
Reserve Additions																						

Table 4 - PRB Reserve Depletion

	Market Share	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Western Energy																						
Dry Fork																						
Production		3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Reserves (EOY)		224.0	220.1	216.2	212.2	208.3	204.4	200.5	196.5	192.6	188.7	184.8	180.8	176.9	173.0	169.1	165.1	161.2	157.3	153.4	149.4	145.5
Reserve Additions																						
Black Hills Energy																						
Wyodak																						
Production		3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Reserves (EOY)		183.0	179.3	175.5	171.8	168.1	164.3	160.6	156.8	153.1	149.4	145.6	141.9	138.2	134.4	130.7	126.9	123.2	119.5	115.7	112.0	108.3
Reserve Additions																						
Total Production		210.0	207.6	205.6	203.0	199.4	197.5	195.7	186.1	185.2	179.4	175.0	174.2	170.2	170.2	169.0	169.0	169.0	167.4	162.8	161.7	161.7
Total Reserves		4,679.0	4,383.4	4,177.7	3,974.8	3,775.4	3,577.9	3,382.2	3,196.1	3,010.9	2,831.5	2,656.5	2,630.4	2,460.1	2,289.9	2,120.9	1,951.9	2,250.5	2,083.1	1,920.3	1,758.7	1,597.0

Wyoming Powder River Basin Federal Coal Lease Status

2019 Tons Produced = 266.7 million tons (down 9.1% (26.4 MM tons) from 2018)

Source (Production Figures):
MSHA Production Tons as of 2/4/2020

Source (Permit Capacity Figures):
openair.wy.gov January 13, 2020

Coordinate data above is accurate to varying degrees — UTM meters NAD'27

Landlines = WY CADNSDI V2 Rail = Digitized from 71/2 min quads. Roads = GPS
Leases = GCDB, I−90 = digitized 7/12 min quad, cities = digitized 71/2 min quads

Legend

- BLM Coal Lease
- Town Buffers Buffalo 2015 RMP
- Lease By Application
- Coal Lease Sale Tract
- Lease Mod
- State Coal Lease (selected leases)
- LMU Mine has a Logical Mining Unit
- Coal Developement Potential Buffalo as 2015 ammended & Casper 2007 RMP
- 59 State Highway
- BNSF Burlington Northern/Sante Fe R.R.
- UP Union Pacific
- Approx. Mined Out/Depleted Areas

**Affected Area displayed for Black Thunder
**Coal Creek Mined Out Area not updated

SCALE
1 0 0.5 1 2 4
Miles

This map is meant for orientation only

NO WARRANTY IS MADE BY THE BUREAU OF LAND MANAGEMENT AS TO THE ACCURACY, RELIABILITY, COMPLETENESS OF THESE DATA FOR INDIVIDUAL USE OR AGGREGATE USE WITH OTHER DATA.

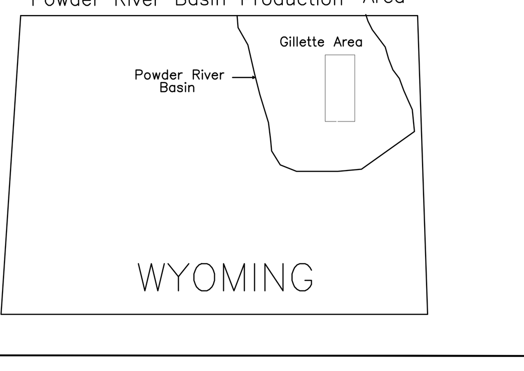
Electronic copies of this map are available at:
http://www.wy.blm.gov/minerals/coal/prb/prb_maps.htm
The filename is PRB_Coal_Lease_Status_Map.dwg and .dxf

UNITED STATES DEPARTMENT OF THE INTERIOR BUREAU OF LAND MANAGEMENT Solid Minerals Group Casper, Wyoming	
Federal Coal Lease Status	
Created 1/8/01	Updated: 2/4/2020
UTM METERS—NAD27 plot 33:175000	File: S:Coal-Geo\PRB coal lease Map\wo-map16_utm.dwg

Landlines are from several sources and include digitized and PLSS data and may not match due to resurveys, etc.

N

Powder River Basin Production Area



Mixed Integer Programming (MIP) in EnCompass

EnCompass utilizes mixed integer programming to determine the optimal solution to capacity expansion, unit commitment, and economic dispatch problems.

Economic Dispatch

The economic dispatch problem seeks to minimize total production costs given a commitment schedule of which units are online and offline in every interval (usually one hour). EnCompass formulates this as a linear problem by using a piecewise-linear representation of unit heat and emission rates, and either a zonal or DC (linearized) powerflow model for transmission. Constraints applied for the economic dispatch include load and ancillary service requirements, transmission limits, fuel limits, environmental limits, storage limits and efficiencies, capacity factor (energy) limits, ramp rates, and resource capacity limits for energy and ancillary services.

Linear programming is a fast, robust, and well-established process that will always return an optimal solution if the problem is feasible (i.e., the constraints are not conflicting). EnCompass uses "soft" constraints for load balance, ancillary services, and certain transmission limits by allowing the limits to be violated subject to input penalties (unserved load and curtailment penalties). In this way, the problem will always be feasible, and any limit violations are reported. In most cases, there is only a single optimal solution. However, if there are multiple units with identical costs, the selection of which units to dispatch is arbitrary. EnCompass will always produce the exact same solution for the same scenario. If a unit that was not dispatched is removed from the scenario, the structure of the problem changes, and a different dispatch of identical units could occur if a different route were taken to find an optimal solution.

When EnCompass is run using the "No Commitment" option, the minimum capacities of resources that are not must-run are relaxed, so that there is no unit commitment problem to solve. In this mode, any startup and no-load costs are converted to linear $/MWh costs using the input Expected Runtime (or if not set, the Minimum Uptime), and are added to a unit's energy and ancillary service costs. This option is the fastest way in which to run EnCompass.

Unit Commitment

The unit commitment problem extends the economic dispatch problem by allowing the selection of which units are online and offline in every interval, given a set of units with fixed commission and retirement dates. This selection uses integer, or whole-number, variables together with the continuous variables from the economic dispatch problem, which is why the methodology is referred to as a "mixed" integer program.

The unit commitment constraints that EnCompass applies includes minimum uptime, minimum downtime, maximum daily and weekly starts, and profiles for which intervals are allowed for unit starts and shutdowns. Fuel requirements and direct costs can be applied to starts and shutdowns, with the option to vary startup requirements based on cold, warm, and hot input definitions. Operating constraints can be applied across a group of units to model load pocket and voltage support requirements, as well as dependencies and other restrictions.

When EnCompass is run using the "Partial Commitment" option, all of the unit commitment costs and constraints are applied, but the number of units committed in any interval is allowed to be a continuous variable between 0 and 1. For example, if the optimal solution included a value of 0.3 for the number of units committed, this would incur 30% of the cost of a start and only allow the unit to dispatch up to 30% of its capacity. The unit would still have to be at least 30% committed for the minimum uptime, and once it goes below that cannot increase until the minimum downtime has passed. The Partial Commitment option turns the unit commitment problem into a linear problem, which makes it faster to solve than the "Full Commitment" option and provides more detail and constraints than the "No Commitment" option.

Capacity Expansion

The capacity expansion problem extends the unit commitment and economic dispatch problem by allowing the selection of new resources, transmission upgrades, and economic retirements. This selection uses also uses integer variables that represent the number of resource additions and retirements in each year. The economic carrying charge is used to represent capital costs for new projects, which increases at the rate of construction escalation and provides the same present value of annual revenue requirements over the book life.

Instead of firm reserve margin constraints, EnCompass uses capacity demand curves to incent meeting reserve margin targets. These can represent "high cliffs" where the penalty for falling short of the target reserve margin is very high ($10,000/kW-year) and then goes to 0 once the reserve margin is met; or they can be downward-sloping curves like those used in PJM, New York and New England for capacity markets.

Each project can have constraints on the maximum additions (incremental) per year, and the minimum and maximum active (cumulative) projects each year. Project Constraints can be used to set these constraints over a group of projects, which can include exclusivity and dependencies.

EnCompass includes a "Partial" optimization option which will allow the number of additions to be a continuous variable. For example, if the optimal solution included a value of 0.3 for the number of additions, this would incur 30% of the capital costs and only consider 30% of the capacity added. Over the operating life of the project, the number of active projects would be at least 30%. If the unit commitment option is "No Commitment" or "Partial Commitment" (which are the typical settings for capacity expansion), Partial project option turns the capacity expansion problem into a linear problem, which makes it faster to solve than the "Full" option. There is also a "Rounded" option which will automatically round up all additions and retirement to the next whole number, but this is typically only used for market-based capacity expansion over large regions. Finally, even with the "Full" option, individual projects can consider partial additions after an input year, which improves the overall runtime.

The MIP Process

If either the unit commitment or capacity expansion options are set to "Full", EnCompass will solve the problem using mixed integer programming. Unlike linear programming, it is not always feasible to find the global optimal solution to a mixed integer problem since the process requires evaluating numerous potential integer solutions. Instead, the problem is considered to be solved when the costs of the best integer solution found is within an input tolerance of the cost of the best remaining partial solution (known as the best bound). The tolerance is measured as the percent difference between the best solution and best bound, and in EnCompass the MIP Stop Basis is input as basis points (1/100th of 1%).

The MIP process first determines the best partial solution using linear programming, as if the option had been set to "Partial". The cost of this solution then becomes the initial best bound, since rounding partial variables up or down will only increase the costs from there. Then, the MIP will create and evaluate several subproblems to find integer solutions and eliminate other possibilities. When a better solution is found, this reduces the best solution cost; when a path is eliminated, this increases the best bound cost. The process continues until the gap between these two costs is within the input tolerance.

Consider a simple example of a one-year capacity expansion problem with three potential projects (P1, P2, and P3) where each project has a maximum of 1. The first step is to solve the partial problem, and assume it provides these results:

- Node 0: Cost = $15.5 million, P1 = 0.3, P2 = 0.8, P3 = 0

The best bound is now $15.5 million, and the MIP will now start to evaluate the subproblems by branching on the partial solutions. For example, two subproblems will be created, one with the constraint P1 = 0 and the other with the constraint P1 = 1. These subproblems are then solved using linear programming, and assume these results:

- Node 1: Cost = $16.1 million, P1 = 0, P2 = 1, P3 = 0
- Node 2: Cost = $15.8 million, P1 = 1, P2 = 0.4, P3 = 0.1

Note that the project results for Node 1 are now all integers, and we have our first feasible solution. Node 2 still has partial projects, so the best bound now increases to $15.8 million. The gap between the best solution and best bound is 1.9%. If the MIP Stop Basis was set to 200, the process will stop and return Node 1 as the best solution. Assume that the MIP Stop Basis is lower, and the process will now branch on Node 2 by setting P2 = 0 and P2 = 1:

- Node 3: Cost = $15.9 million, P1 = 1, P2 = 0, P3 = 0.3
- Node 4: Cost = $16.2 million, P1 = 1, P2 = 1, P3 = 0

Node 4 is a feasible integer solution, but has a higher cost than Node 1, so the process does not do anything else with Node 4 (that "branch has been pruned"). Node 3 is a partial solution, so the best bound increases to $15.9 million, leaving a gap of 1.3% with the best solution (Node 1). Assume that the MIP Stop Basis is less than 120, so the process will now branch on Node 3 by setting P3 = 0 and P3 = 1:

- Node 5: Cost = $15.9 million, P1 = 1, P2 = 0, P3 = 0
- Node 6: Cost = $16.3 million, P1 = 1, P2 = 0, P3 = 1

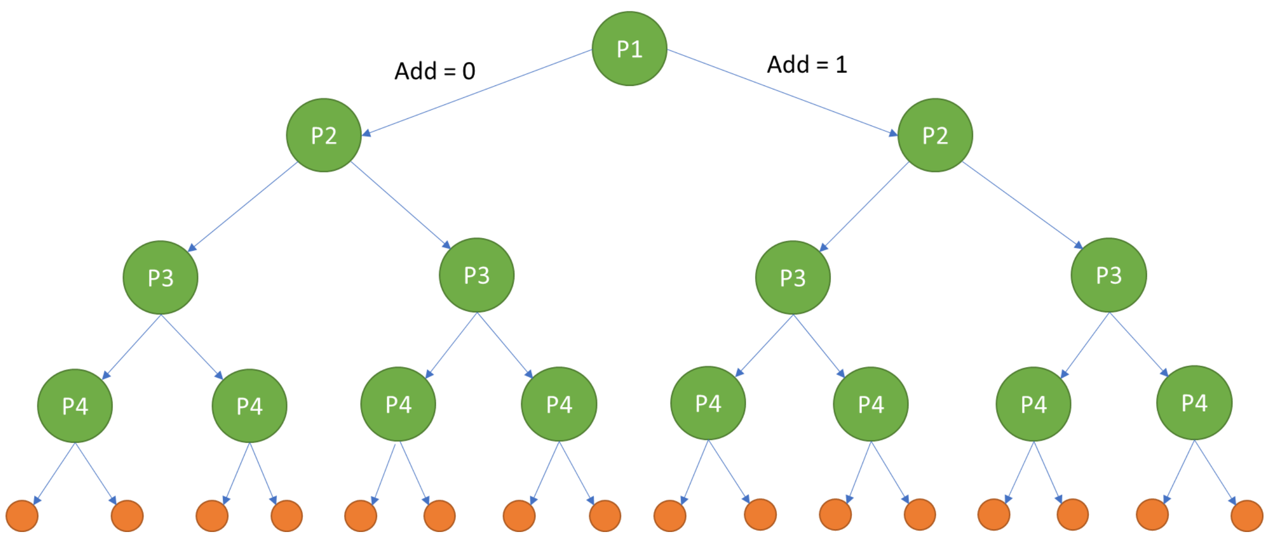
The process is now left with only integer solutions, so the best bound and best solution are both $15.9 million, the gap is 0%, and Node 5 is the optimal solution.

Objective Functions and the Unified Solution

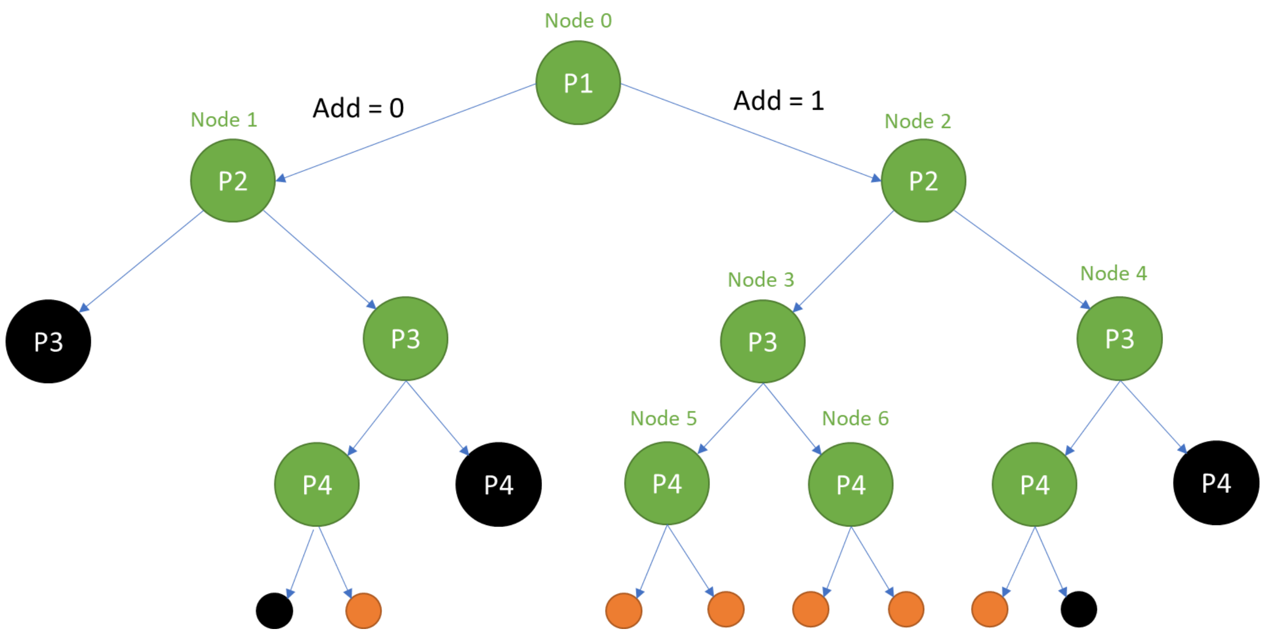
Models like Strategist and EGEAS use dynamic programming to enumerate all feasible nodes. Each node is run through a non-linear probabilistic sub-module to determine production costs, which are added to the capital costs to determine the selected objective function value. The objective function is then ranked across all those nodes to determine the optimal plan. In this simple problem, there were 2 x 2 x 2 = 8 nodes to evaluate with dynamic programming, and 7 nodes with mixed integer programming. In a typical multi-year expansion problem, there are usually thousands of integer variables that can take values larger than 1. This makes the number of nodes to evaluate with a dynamic program skyrocket and requires additional constraints to be imposed to bring that number down. With mixed integer programming, the number of nodes is manageable since only those nodes that show promise are evaluated and used to look for other nodes.

With dynamic programming, the objective function can be distorted between the production cost sub-module and the capacity expansion decision. For example, if the objective function is to minimize total utility costs plus emission externalities, the ranking of nodes may pick up externality costs from the production cost sub-module, even if that was not included in the commitment and dispatch objective function. With mixed integer programming, there is no decoupling of capacity expansion, unit commitment, and economic dispatch, so all three of these decisions work together to minimize the single selected objective function. As an example, given the objective function of minimizing total utility costs plus emission externalities, a low-cost alternative might be to displace a MWh from a higher emitting resource, such as a coal-fired unit, with a MWh from a lower emitting unit such as either renewable or gas-fired generation. Depending on the design of the model, a dynamic programming algorithm might recognize one, both or neither of these options and possibly not produce the most economical alternative. Conversely, a mixed integer model that co-optimizes production cost and capacity expansion will evaluate all options for minimizing the objective function.

To illustrate this further, assume a fourth potential project, P4, is considered. The dynamic programming approach builds a decision tree, with a branch for every project decision (add 0 or 1). The result is 16 feasible solutions, shown in the figure below as orange leaves on the tree, each of which must be evaluated with the production cost sub-module:



Because the mixed integer process uses a unified solution, it knows the change in costs as the tree is being built and can prune branches that will always produce higher-cost feasible solutions. In the figure below, those pruned branches are shown in black, and the nodes from the example above are identified:



Another key advantage is that in the MIP process, each node can be evaluated using the solution to the prior node as a starting point, greatly reducing the processing time required to evaluate new nodes. The non-linear production cost sub-module of the dynamic program cannot "learn" as it goes, and each feasible solution must be evaluated from scratch.

To minimize the size of the problem that must be solved, EnCompass does not include the variables, constraints, and costs of any decisions which are fixed. This means that if the selections of one project in a capacity expansion optimization is "frozen" and the case is run again, the objective function values will be lower since the capital and fixed operating costs of that frozen project are not included. Since the convergence threshold is a percentage of the objective function, that gap becomes tighter, and a different overall plan with a slightly lower cost may be chosen.

The structure of the problem can also impact the selection of which variables are branched and the path that is used to find solutions. For example, removing limits that are never binding or resources and projects that are never utilized does not change the underlying economics, but it does make the problem smaller, which could lead to different approaches and different solutions that are both within the convergence tolerance. For capacity expansion problems where the MIP Stop Basis is set to a low value like 50 (0.5%), multiple solutions that are within that threshold should be considered to have comparable costs over the multi-year optimization period.

Xpress Optimization Suite

EnCompass uses the Xpress Optimization Suite from FICO to solve the linear and mixed integer problems described above. The branch-and-bound process can be sped up considerably by making better choices on which variables to branch on, and by performing heuristic searches for additional nodes. Xpress uses these techniques and others to provide the best possible performance for solving mixed integer problems.

One of the key techniques to reduce runtime for large problems is parallelism. This allows multiple “leaf” nodes to be solved simultaneously, based on the number of available computing cores and memory. As a result, the solution path may be different when solving using one set of computing resources versus another. This could produce two different solutions that are both feasible and within the input gap threshold.