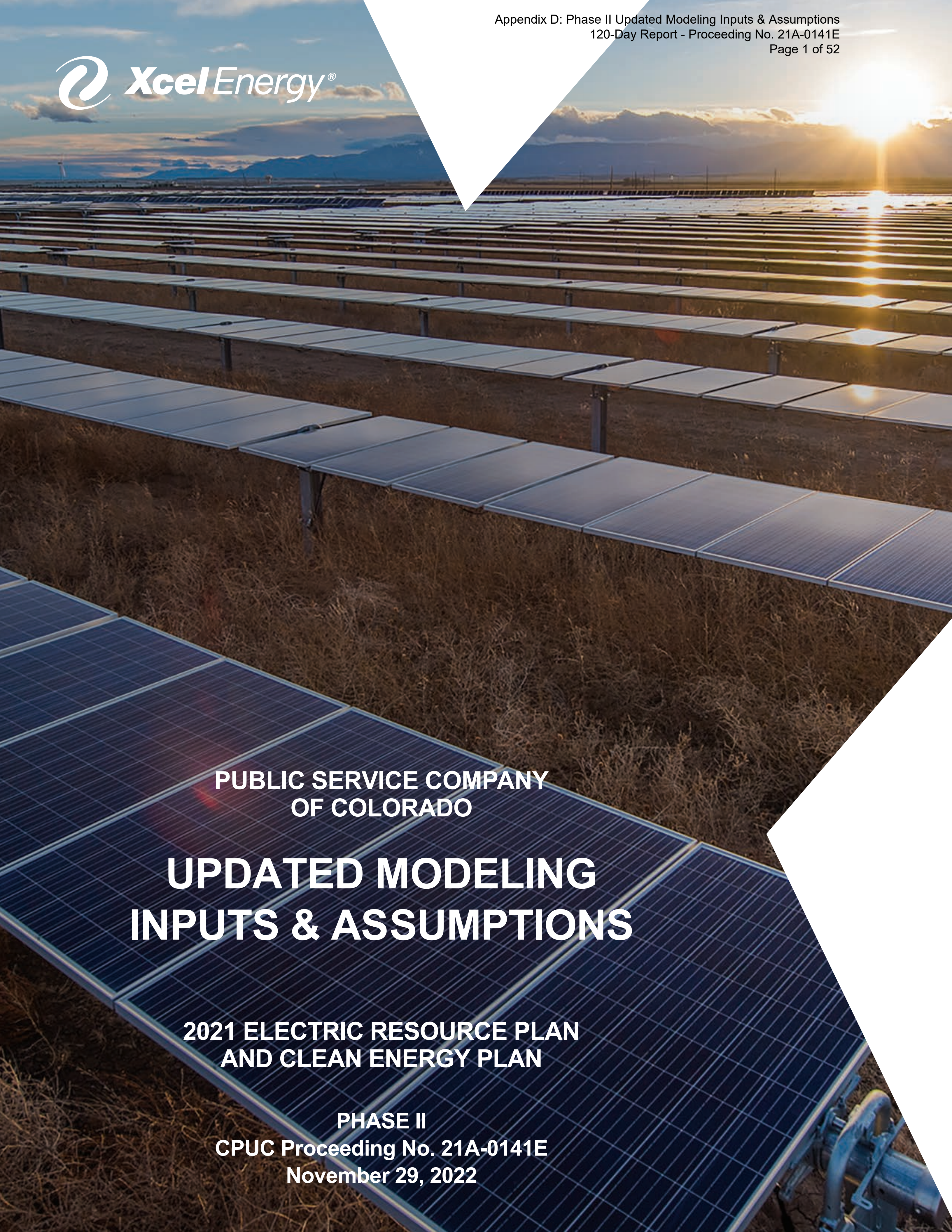

PUBLIC SERVICE COMPANY
OF COLORADO

UPDATED MODELING INPUTS & ASSUMPTIONS

2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN

PHASE II
CPUC Proceeding No. 21A-0141E
November 29, 2022

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2021 ERP & CEP MODELING INPUTS AND ASSUMPTIONS UPDATE

Introduction

As part of its 2021 Electric Resource Plan and Clean Energy Plan ("2021 ERP & CEP") filed in Proceeding No. 21A-0141E, Public Service Company of Colorado ("Public Service" or the "Company") provided a list of modeling assumptions in Section 2.14 of Volume 2 filed on March 31, 2021. This list included both discrete values for certain assumptions or, in some cases, the methodologies to be used to develop the values.

In its 2021 ERP & CEP Phase I Decision (Decision Nos. C22-0459 and C22-0559, collectively referred to as the "Phase I Decision"), the Commission either: (1) approved the assumptions and methodologies as originally set forth in Section 2.14 of Volume 2 of the 2021 ERP & CEP; (2) approved assumptions and methodologies set forth in the Updated Non-Unanimous Partial Settlement Agreement (filed on April 26, 2022); or (3) modified certain assumptions and methodologies.

Paragraph 316 of the Commission's Phase I Decision (C22-0459) requires as follows:

> Consistent with past practice, we order Public Service to file, prior to issuing the all-source RFPs, a complete list of the modeling inputs and assumptions consistent with the presentation in Section 2.14 of Volume 2 and indicate which parameters were updated for bid evaluation and selection purposes. To the extent that any parameters are still to be updated after the RFPs are issued but prior to the Phase II resource evaluation, the Company should identify the parameters in the list that need to be updated and provide the updated values in the 120-Day Report. These updates should be consistent with the Commission's other rulings in the Phase I decision.

Accordingly, consistent with Section 2.14 of Volume 2 of the 2021 ERP & CEP and the Commission's Phase I Decision, the updated modeling assumptions and/or methodologies to be used in Phase II are presented below. As required by paragraph 316 of Decision No. C22-0459, the Company has indicated which of the modeling assumptions have been updated since the Phase I filing (designated in the assumption header as "Updated") and those that have not changed since the Phase I filing (designated in the header as "No Change"). The table numbers in this modeling assumptions update document correspond with the respective table numbers in Volume 2, Technical Appendix, Rev. 2 of the Company's Phase I filing. New tables in this modeling assumptions update document that do not have a corresponding table in Volume 2 are labeled sequentially as "Table MAU" (Modeling Assumptions Update).

1. Capital Structure and Discount Rate (Updated)

The rates shown in Table 2.14-1 are used to calculate the capital revenue requirements of generic resources. The after-tax WACC of 6.42% 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	43.90%	3.71%	1.63%	1.23%
Common Equity	55.69%	9.30%	5.18%	5.18%
Short-Term Debt	0.41%	1.79%	0.01%	0.01%
Total			**6.82%**	**6.42%**

2. Gas Price Forecasts (Updated)

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; Wood Mackenzie and IHS Markit provide data out to 2050, S&P Global through 2040, and NYMEX through 2034. 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. High and low gas price sensitivities adjust the annual growth rate up and down by 50 percent from the base gas price starting in year 2025 when the long-term fundamentals-based forecasts are blended with the market information (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	4C On-Peak	4C Off-Peak	Midway On-Peak	Midway Off-Peak	CIG RM	4C On-Peak	4C Off-Peak	Midway On-Peak	Midway Off-Peak
2022	$1.77	$5.57	$62.48	$51.88	$49.79	$40.99	$5.57	$62.48	$51.88	$49.79	$40.99	$5.57	$62.48	$51.88	$49.79	$40.99
2023	$1.58	$5.54	$49.47	$42.80	$40.23	$33.57	$5.54	$49.47	$42.80	$40.23	$33.57	$5.54	$49.47	$42.80	$40.23	$33.57
2024	$1.51	$4.69	$38.54	$35.25	$32.15	$28.53	$4.69	$38.54	$35.25	$32.15	$28.53	$4.69	$38.54	$35.25	$32.15	$28.53
2025	$1.55	$3.90	$37.18	$34.77	$32.34	$29.52	$3.51	$33.42	$31.25	$29.07	$26.53	$4.30	$40.95	$38.29	$35.61	$32.50
2026	$1.59	$4.13	$35.16	$34.57	$31.37	$29.57	$3.61	$30.74	$30.22	$27.42	$25.85	$4.67	$39.78	$39.11	$35.48	$33.45
2027	$1.62	$4.28	$33.50	$34.75	$30.83	$30.00	$3.68	$28.76	$29.83	$26.46	$25.76	$4.93	$38.59	$40.03	$35.50	$34.56
2028	$1.66	$4.38	$32.72	$35.35	$31.11	$31.60	$3.72	$27.79	$30.02	$26.42	$26.84	$5.09	$38.08	$41.15	$36.21	$36.78
2029	$1.70	$4.29	$31.00	$34.32	$30.46	$31.60	$3.60	$26.05	$28.85	$25.60	$26.56	$5.04	$36.45	$40.35	$35.82	$37.15
2030	$1.77	$4.28	$29.50	$34.58	$30.04	$32.14	$3.60	$24.82	$29.09	$25.27	$27.04	$5.03	$34.66	$40.63	$35.29	$37.77
2031	$1.80	$4.37	$28.81	$34.11	$29.24	$31.74	$3.64	$24.00	$28.41	$24.35	$26.43	$5.18	$34.19	$40.48	$34.70	$37.66
2032	$1.83	$4.44	$29.28	$34.60	$28.93	$32.11	$3.67	$24.18	$28.58	$23.90	$26.52	$5.32	$35.03	$41.40	$34.62	$38.42
2033	$1.91	$4.57	$29.84	$36.18	$29.36	$33.33	$3.72	$24.32	$29.48	$23.92	$27.16	$5.54	$36.19	$43.88	$35.60	$40.42
2034	$1.97	$4.71	$29.70	$36.42	$29.14	$33.38	$3.78	$23.83	$29.21	$23.38	$26.77	$5.80	$36.58	$44.85	$35.89	$41.11
2035	$2.04	$4.88	$30.08	$37.43	$29.35	$34.55	$3.85	$23.71	$29.50	$23.13	$27.23	$6.12	$37.69	$46.90	$36.77	$43.29
2036	$2.10	$5.03	$29.66	$37.19	$28.79	$34.49	$3.91	$23.04	$28.88	$22.36	$26.79	$6.39	$37.71	$47.28	$36.60	$43.85
2037	$2.17	$5.19	$30.34	$38.16	$29.41	$35.57	$3.97	$23.19	$29.17	$22.48	$27.19	$6.71	$39.18	$49.29	$37.99	$45.94
2038	$2.24	$5.37	$30.60	$39.00	$29.74	$36.53	$4.04	$23.00	$29.31	$22.35	$27.45	$7.06	$40.18	$51.21	$39.06	$47.97
2039	$2.31	$5.60	$31.89	$40.52	$30.48	$37.41	$4.12	$23.48	$29.83	$22.44	$27.54	$7.51	$42.73	$54.29	$40.84	$50.13
2040	$2.39	$5.83	$33.21	$42.14	$32.22	$39.50	$4.21	$23.97	$30.41	$23.25	$28.51	$7.97	$45.38	$57.57	$44.02	$53.97
2041	$2.46	$6.06	$33.57	$42.72	$32.64	$40.03	$4.29	$23.77	$30.25	$23.11	$28.35	$8.43	$46.72	$59.46	$45.43	$55.71
2042	$2.54	$6.26	$34.50	$43.53	$33.57	$40.93	$4.36	$24.04	$30.34	$23.40	$28.53	$8.85	$48.78	$61.55	$47.47	$57.88
2043	$2.61	$6.44	$34.98	$44.04	$33.91	$41.66	$4.43	$24.03	$30.25	$23.29	$28.62	$9.24	$50.17	$63.15	$48.63	$59.75
2044	$2.69	$6.71	$35.99	$45.25	$35.01	$43.03	$4.52	$24.22	$30.46	$23.56	$28.97	$9.82	$52.66	$66.22	$51.23	$62.97
2045	$2.77	$6.93	$37.45	$47.34	$35.73	$44.91	$4.59	$24.82	$31.37	$23.67	$29.76	$10.30	$55.65	$70.35	$53.09	$66.74
2046	$2.85	$7.12	$38.23	$47.59	$36.28	$44.90	$4.65	$24.99	$31.11	$23.72	$29.35	$10.72	$57.57	$71.67	$54.64	$67.61
2047	$2.94	$7.38	$38.54	$48.53	$36.29	$45.60	$4.74	$24.75	$31.17	$23.31	$29.29	$11.31	$59.05	$74.36	$55.60	$69.87
2048	$3.02	$7.67	$39.30	$49.06	$36.79	$45.65	$4.83	$24.77	$30.92	$23.19	$28.77	$11.96	$61.34	$76.58	$57.43	$71.25
2049	$3.11	$7.95	$40.59	$50.54	$37.64	$47.16	$4.92	$25.12	$31.28	$23.30	$29.19	$12.63	$64.49	$80.30	$59.81	$74.94
2050	$3.20	$8.24	$42.59	$52.92	$39.83	$49.78	$5.01	$25.90	$32.18	$24.22	$30.27	$13.32	$68.86	$85.56	$64.40	$80.48

**Coal prices are delivered prices, while gas and market prices are hub prices.*

3. Firm Fuel Charges (No Change)

The Company will apply a levelized charge of $11.98/kW-year 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. Following bid submittal in Phase II, the Company will review and estimate, as necessary, the firm fuel costs for proposed projects based on the bid characteristics.

4. Market Prices (Updated)

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 tie 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 On and Off-peak power price forecasts provided by Wood Mackenzie, IHS Energy and S&P Global.

Annual average values for the Four Corners Market and Midway are summarized in Table 2.14-2 above and have zero CO_2 cost assumptions

5. Coal Price Forecasts (Updated)

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 Wood Mackenzie 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 above.

6. Reserve Margin (No Change)

Consistent with the updated Planning Reserve Margin study approved in Phase I, resource need is determined by applying an ~19% planning reserve margin (“PRM”) to 2023-2026 forecast annual peak load and an 18% PRM thereafter. Annual peak load is determined from the 50th percentile demand forecast.

7. Surplus Capacity Credit (No Change)

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 on 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 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

8. Seasonal Capacity Purchases (Updated)

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 cost-effective bids are received in Phase II with in-service dates and capacity that meet the firm capacity need for summer 2024, such bids will be utilized rather than the generic purchase.

9. Emissions Price Forecasts (Updated)

CO2 Price Forecast

Base modeling assumptions are either a $0/ton CO_2 proxy price or the Social Cost of Carbon ("SCC"). The SCC values utilized are shown in Table 2.14-4 below. The Company will utilize a SCC value beginning at $69.33/short ton in 2020. The SCC values will be based upon the February 2021 update to the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990, published by the Federal Interagency Working Group on Social Cost of Greenhouse Gases, and will use the 2.5 percent discount rate from that publication. The Company will use the values from the cited report, converted to dollars per short ton and expressed in nominal dollars.

Methane Price Forecast

A repricing sensitivity scenario will apply the social cost of methane ("SCM") to the natural gas fuel supply to account for upstream methane leakage and methane emissions from combustion. As with the SCC described above, the Company will utilize the federal government's most recent assessment of the SCM (February 2021),[1] using the value calculated at a 2.5 percent discount rate. Converted to nominal dollars pers short ton, the SCM value begins at $1771.92/short ton in 2020.

To estimate upstream methane emissions, the Company will utilize the methodology and assumptions similar to those provided by Guidehouse Inc. in Proceeding No. 22A-0309EG. The Company will assume a methane leakage rate of 0.25% (similar to the 0.2089% system leakage rate from Guidehouse Inc. and consistent with the range of methane leakage rates required in the Phase I Decision), and a conversion rate of 47,790,860 Btu per short ton CH4, derived from the U.S. Environmental Protection Agency (EPA).[2] To estimate methane emissions from combustion, the Company will assume the U.S. EPA's emissions factor of 2.3 pounds of CH4 per million standard cubic feet of natural gas fired.[3]

[1] February 2021 update to the "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990"
[2] US Environmental Protection Agency - Coal Mine Methane Units Converter; https://www.epa.gov/cmop/coal-mine-methane-units-converter
[3] US Environmental Protection Agency - AP 42, Fifth Edition, Volume I Chapter 1: External Combustion Sources – 1.4 Natural Gas Combustion
https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-fifth-edition-volume-i-chapter-1-external-0

Table 2.14-4: CO2 Cost Forecast

CO2 Costs ($ per short ton)		
Year	**$0 CO2**	**SCC**
2021	$0.00	$71.92
2022	$0.00	$74.59
2023	$0.00	$77.34
2024	$0.00	$80.17
2025	$0.00	$83.08
2026	$0.00	$86.08
2027	$0.00	$89.16
2028	$0.00	$92.33
2029	$0.00	$95.60
2030	$0.00	$98.95
2031	$0.00	$102.47
2032	$0.00	$106.09
2033	$0.00	$109.81
2034	$0.00	$113.64
2035	$0.00	$117.57
2036	$0.00	$121.62
2037	$0.00	$125.79
2038	$0.00	$130.07
2039	$0.00	$134.47
2040	$0.00	$139.00
2041	$0.00	$143.62
2042	$0.00	$148.36
2043	$0.00	$153.24
2044	$0.00	$158.25
2045	$0.00	$163.41
2046	$0.00	$168.70
2047	$0.00	$174.15
2048	$0.00	$179.74
2049	$0.00	$185.48
2050	$0.00	$191.39

10. Inflation / Construction Escalation Rates (No Change)

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 IHS 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.

11. DSM Forecasts (Updated)

On July 1, 2022 the Company filed its DSM Strategic Issues application in Proceeding No. 22A-0309EG, which seeks, in part, approval of its 2024-2028 demand response goals. Additionally, the Company provided a longer-term forecast of demand response goals through 2030. The specific goals and forecasts were developed in conjunction with a demand response potential study conducted by the Brattle Group during the spring of 2022. At the time of the Phase II RFP issuance, the DSM Strategic Issues proceeding is pending approval by the Colorado Public Utilities Commission. As part of Decision No. C22-0459 in Proceeding No. 21A-0141E, the Commission ordered the Company to conduct a reoptimized sensitivity assuming 200 MW of incremental demand response capacity in increments of 25 MW per year between 2023 and 2027. However, the Company's proposed demand response goals in the DSM Strategic Issues proceeding and reflected in the Base case assumptions in the Phase II modeling exceed the assumptions in the Commission's required sensitivity analysis. Accordingly, the Company believes the best course that is most consistent with the Phase I Decision is to conduct the sensitivity analysis only if the Commission issues an order in Proceeding No. 22A-0309EG with increased demand response goals relative to those proposed by the Company. Otherwise, the Company will have a base forecast that assumes lower demand response goals than the goals proposed in Proceeding No. 22A-0309EG, with a sensitivity analysis more in-line with the Company's proposal in its DSM Strategic Issues proceeding. The Company's approach avoids that outcome while capturing higher levels of demand response goals, consistent with the general direction of the Phase I Decision.

Table 2.14-6: Demand Response Goals (MW)

Demand Response (MW)		
Year	Un-Adjusted for Reserve Margin	Adjusted for Reserve Margin
2022	496	585
2023	516	616
2024	538	641
2025	563	671
2026	597	711
2027	631	745
2028	679	801
2029	725	856
2030	767	905
2031	767	905
2032	767	905
2033	767	905
2034	767	905
2035	767	905
2036	767	905
2037	767	905
2038	767	905
2039	767	905
2040	767	905
2041	767	905
2042	767	905
2043	767	905
2044	767	905
2045	767	905
2046	767	905
2047	767	905
2048	767	905
2049	767	905
2050	767	905

12. Transmission Network Upgrade Costs (No Change)

Estimates of transmission network upgrades costs for the Phase I and II 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; the entire cost of the required upgrade will be assigned to the relevant portfolio(s). 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 ("CPCN") at the time of the bid evaluation. See Section 3 in the Request for Proposal ("RFP") documents for additional process detail including information for bids proposing to interconnect to the Colorado's Power Pathway transmission project.

13. Transmission Interconnection Costs (No Change)

Estimates of transmission interconnection costs for the Phase I and II 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 RFP documents for additional process detail.

14. Generation Capacity Credit for Wind Resources (No Change)

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 II modeling purposes incremental, generic wind resources receive generation capacity credit as shown in Table 2.14-7. The Company will use the EnCompass ELCC curve functionality to assign ELCC's to generic wind.

Table 2.14-7: Phase II Average ELCC Applied to Generic Wind

MW Range	ELCC
0-1000 MW	19.4%
1001-2000 MW	14.5%
> 2000 MW	11.3%

For initial Phase II portfolio selection purposes, 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 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 use the EnCompass ELCC curve functionality to assign ELCC's to wind bids.

Table 2.14-8: Phase II Average ELCC Applied to Incremental Wind

MW Range	ERZ-1	ERZ-2	ERZ-3	ERZ-5 (50%)	ERZ-5 (44%)
0-250	15.9%	12.8%	33.6%	24.2%	17.6%
251-500	13.1%	11.4%	28.6%	21.0%	15.8%
501-1000	10.0%	10.3%	22.6%	17.7%	13.4%
1001-2000	6.9%	8.6%	13.4%	12.9%	9.8%
2001-3000	5.0%	7.1%	6.1%	9.5%	7.5%

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; descriptions of each of the four ERZs shown in the table are included in the Renewable RFP documents. 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.

15. Generation Capacity Credit for Solar Resources (Updated)

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 II modeling purposes, incremental, generic utility solar resources receive generation capacity credit as shown in Table 2.14-9; the values in the table have been updated to align with the final ELCC study values. The Company will use the EnCompass ELCC curve functionality to assign ELCCs to generic solar resources.

Table 2.14-9: Phase II Average ELCC Applied to Generic Utility Solar

MW Range	ELCC
0-1000 MW	21.1%
1001-2000 MW	10.7%
> 2000 MW	5.4%

For initial Phase II portfolio selection purposes, 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 is provided in Table 2.14-10; descriptions of the relative geographic areas of each of the six solar resource zones shown in the table are included in the Renewable RFP documents. The Company will use the EnCompass ELCC curve functionality to assign ELCCs to solar bids.

Table 2.14-10: Phase II Average ELCC Applied to Incremental Utility Solar

MW Range	MTN	NFR	SE	SFR	SLV	WS
0-100	21.4%	33.5%	29.3%	15.4%	28.4%	36.3%
101-250	18.4%	30.5%	26.1%	13.9%	24.7%	30.5%
251-500	14.2%	26.2%	21.2%	11.1%	18.8%	24.5%
501-1000	8.7%	16.8%	12.9%	7.6%	10.0%	14.4%
1001-2000	5.2%	7.3%	6.8%	5.2%	5.5%	6.2%
2001-3000	3.6%	3.2%	3.7%	3.7%	4.1%	2.9%

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.

16. Generation Capacity Credit for Hydro and Storage Resources (Updated)

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 91.8%, and (3) the storage components of solar hybrid facilities acquired prior to the 2022 All-Source Solicitation receive 60.5% generation capacity credit.

Consistent with the Commission's Phase I Decision and the results of the updated storage ELCC study required therein through approval of the Updated Non-Unanimous Partial Settlement Agreement (updated storage ELCC study attached as Attachment A to these Updated Modeling Assumptions), incremental standalone and hybrid storage resources in Phase II will receive generation capacity credit during portfolio creation according to Table 2.14-12 below:

Table 2.14-12: Phase II Average ELCC Applied to Incremental Storage

MW Range	2-HR	4-HR	8-HR
0-500	83%	89%	91%
>500	58%	70%	77%

The updated storage ELCC study report documents multiple modeling assumptions that impact the result and/or differ from those utilized in the consultant's prior analyses and could have resulted in unexpectedly high values, the Company may conduct sensitivity analyses to determine if using incremental storage ELCC values consistent with

Attachment A to the Company's Statement of Position (developed consistent with the Non-Unanimous Partial Settlement Agreement terms), as compared to the values in the updated storage ELCC study, result in materially different portfolios of resources. The results of any such sensitivity analyses would be presented and documented in the 120-Day Report. Values from Attachment A of the Company's Statement of Position and the Updated Settlement Agreement are shown in Table MAU-1 below:

Table MAU-1: Phase II Average ELCC Applied to Incremental Storage – Sensitivity Case

MW Range	2-HR	4-HR	8-HR
0-500	38.6%	60.0%	88.3%
>500	26.9%	40.0%	49.3%

17. Resource Acquisition Period (Updated)

The RAP extends from 2021 through 2030; however, the Company will not acquire in this Proceeding any resources with in-service dates after December 31, 2028 (Decision No. C22-0459, ¶165).

18. Planning Period (No Change)

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.

19. SO2 Effluent Costs and Allocations (No Change)

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.

20. NO_x Effluent Costs and Allocations (No Change)

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.

21. Mercury Effluent Costs and Allocations (No Change)

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.

22. Spinning Reserve Requirement (No Change)

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 is consistent with NWPP requirements, and as used in the Phase I modeling. The cost of spinning reserve is inherently embedded in the EnCompass model by assigning a spin requirement and the spinning capability of each resource.

23. Emergency Energy Costs (Updated)

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 is set at $50,000/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 $50,000/MWh costs were replaced in post-processing with more reasonable values of $2,000/MWh ($2020) escalating at 2%. If this value results in the model selecting emergency energy as an economic alternative, the value may need to be adjusted and any adjustments will be coordinated with the IE.

24. Wind/Solar Integration Costs and Storage Integration Credits (Updated)

Per Commission directive, the Company has discontinued the application of integration costs, both as an adder to the cost of wind and solar bids and as a credit to storage bids (Decision No. C22-0459, ¶ 257).

25. Owned Unit Modeled Operating Characteristics and Costs (No Change)

Company-owned units are 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

26. Thermal PPA Operating Characteristics and Costs (No Change)

PPAs 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

27. Renewable Energy PPA Operating Characteristics and Costs (No Change)

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. Emission rates for SO_2, NO_x, CO_2, Mercury and PM if applicable

28. Load Forecast (Updated)

Table 2.14-15 below provides the updated Base ERP forecast (the Company notes that Table 2.14-15 below consolidates and updates Table 2.14-15, Table 2.14-20, and Table 2.14-25 from Volume 2, Rev. 2). Both the energy and peak demands are higher than the Base forecast used in Phase I. Key drivers of the increase are the incorporation of the Company's Beneficial Electrification programs used in the DSM Strategic Issues filing and the addition of a new, large transmission-level customer that was not included in the Phase I forecast. The updated forecast also includes more embedded beneficial electrification than the forecast used in Phase I.[4]

The Company made no methodological changes to the Roadmap and Low scenarios, though both included updates to adjusted assumption values to reflect updated historical data.

[4] As directed by ¶178 of Decision No. C22-0459, the Company has corrected the mathematical error in its beneficial electrification forecast.

Table 2.14-1: Native Demand and Energy Forecast

	Base Forecast		Roadmap Forecast		Low Forecast	
Year	Demand (MW)	Energy (GWh)	Demand (MW)	Energy (GWh)	Demand (MW)	Energy (GWh)
2022	7,150	34,017	7,163	34,368	7,150	34,017
2023	7,140	33,906	7,160	34,401	7,100	33,760
2024	7,195	34,410	7,231	35,054	7,123	34,044
2025	7,259	35,028	7,289	35,897	7,154	34,478
2026	6,990	34,760	7,044	35,902	6,859	34,047
2027	7,066	35,507	7,119	37,047	6,902	34,600
2028	7,165	36,409	7,263	38,334	6,938	35,277
2029	7,279	37,260	7,396	39,532	7,009	35,922
2030	7,402	38,334	7,553	40,975	7,094	36,793
2031	7,527	39,475	7,639	42,444	7,177	37,721
2032	7,685	40,880	7,793	44,221	7,264	38,877
2033	7,836	42,045	7,975	45,758	7,367	39,825
2034	7,954	43,121	8,130	47,266	7,451	40,713
2035	8,058	44,105	8,260	48,706	7,522	41,519
2036	8,152	45,106	8,329	50,216	7,550	42,298
2037	8,276	46,080	8,488	51,665	7,631	43,063
2038	8,388	47,142	8,579	53,260	7,707	43,922
2039	8,508	48,169	8,748	54,807	7,794	44,777
2040	8,606	49,134	8,908	56,324	7,832	45,537
2041	8,709	49,982	9,046	57,345	7,905	46,246
2042	8,802	50,856	9,123	58,397	7,980	47,011
2043	8,642	50,342	9,167	58,008	7,803	46,396
2044	8,716	51,177	9,277	58,973	7,826	47,046
2045	8,795	51,941	9,164	59,672	7,882	47,695
2046	8,871	52,777	9,538	60,404	7,945	48,442
2047	8,945	53,637	9,669	61,068	8,006	49,211
2048	9,020	54,542	9,878	61,826	8,028	49,924
2049	9,094	55,268	10,150	62,338	8,079	50,529
2050	9,207	56,532	10,128	62,950	8,179	51,671

29. Prospective New Load (Updated)

To recognize that several potentially significant actions that would affect the load forecast are currently in various stages of development, the Company will conduct an additional high load sensitivity that will add a large unspecified retail and/or wholesale load increase that might occur prior to or near the conclusion of Phase II. The added load is shown in Table MAU-2 below:

Table MAU-2: Prospective New Load Forecast

Year	Peak (MW)	Energy (GWh)
2022	371	2,030
2023	382	2,091
2024	393	2,154
2025	405	2,218
2026	417	2,285
2027	430	2,353
2028	442	2,424
2029	456	2,497
2030	469	2,572
2031	484	2,649
2032	498	2,728
2033	513	2,810
2034	528	2,894
2035	544	2,981
2036	561	3,071
2037	577	3,163
2038	595	3,258
2039	612	3,355
2040	631	3,456
2041	650	3,560
2042	669	3,667
2043	689	3,777
2044	710	3,890
2045	731	4,007
2046	753	4,127
2047	776	4,251
2048	799	4,378
2049	823	4,509
2050	848	4,645

30. Base Distributed Energy Resource Forecasts (Updated)

The Behind the Meter solar and Community Solar Gardens inputs are based on the most recent Company forecasts which include the projected installation of capacity and forecasted market adoption from the 2022-25 RE Plan (Proceeding No. 21A-0625EG). Behind the Meter solar is modeled assuming a degradation of half of one percent annually. Community Solar Gardens are modeled assuming a degradation of half of one percent annually and a 20-year contract life.

Table 2.14-18: Distributed Solar Nameplate Capacity Forecast

Distributed Solar (Nameplate MW)			
Year	Behind the Meter	Community Gardens	Total
2022	577	117	694
2023	675	143	818
2024	779	237	1,017
2025	888	324	1,211
2026	982	361	1,343
2027	1,066	458	1,524
2028	1,157	638	1,794
2029	1,253	639	1,892
2030	1,339	695	2,034
2031	1,417	751	2,168
2032	1,499	806	2,305
2033	1,583	862	2,445
2034	1,671	914	2,585
2035	1,761	964	2,725
2036	1,851	1,013	2,865
2037	1,944	1,067	3,010
2038	2,038	1,109	3,147
2039	2,135	1,148	3,283
2040	2,230	1,176	3,406
2041	2,324	1,216	3,540
2042	2,421	1,242	3,663
2043	2,518	1,271	3,789
2044	2,615	1,238	3,853
2045	2,711	1,212	3,923
2046	2,807	1,230	4,037
2047	2,903	1,194	4,097
2048	3,000	1,083	4,083
2049	3,099	1,133	4,232
2050	3,200	1,133	4,332

Table 2.14-19: Distributed Solar Firm Capacity Forecast

Distributed Solar (Firm MW)			
Year	Behind the Meter	Community Gardens	Total
2022	219	72	290
2023	139	59	198
2024	155	87	243
2025	172	112	284
2026	185	122	307
2027	197	148	345
2028	208	193	401
2029	221	193	413
2030	231	206	437
2031	240	218	458
2032	249	230	479
2033	257	241	499
2034	266	251	518
2035	274	261	535
2036	282	270	552
2037	290	279	569
2038	297	286	583
2039	304	292	596
2040	310	297	606
2041	315	303	618
2042	320	306	626
2043	324	310	635
2044	328	310	639
2045	331	310	642
2046	334	313	647
2047	336	313	649
2048	337	313	650
2049	338	321	659
2050	338	321	659

31. High Distributed Energy Resource Forecasts (Included in Low Load Scenario) (Updated)

Table 2.14-23: Distributed Solar Forecast (Nameplate MW)

Distributed Solar (Nameplate MW)			
Year	Behind the Meter	Community Gardens	Total
2022	577	117	694
2023	678	143	821
2024	791	237	1,028
2025	908	324	1,232
2026	1,017	371	1,388
2027	1,125	492	1,617
2028	1,245	717	1,963
2029	1,380	719	2,099
2030	1,511	790	2,301
2031	1,643	860	2,503
2032	1,789	930	2,719
2033	1,942	999	2,942
2034	2,104	1,066	3,171
2035	2,275	1,130	3,405
2036	2,452	1,193	3,645
2037	2,636	1,261	3,897
2038	2,828	1,317	4,145
2039	3,028	1,370	4,398
2040	3,227	1,411	4,638
2041	3,430	1,465	4,895
2042	3,641	1,505	5,146
2043	3,856	1,547	5,403
2044	4,075	1,528	5,602
2045	4,293	1,515	5,808
2046	4,514	1,538	6,051
2047	4,740	1,493	6,233
2048	4,972	1,353	6,325
2049	5,210	1,416	6,626
2050	5,458	1,416	6,874

Table 2.14-24: Distributed Solar (Firm MW)

Distributed Solar (Firm MW)			
Year	Behind the Meter	Community Gardens	Total
2022	219	72	290
2023	140	59	199
2024	157	87	245
2025	175	112	287
2026	190	125	315
2027	205	157	362
2028	220	211	431
2029	236	211	447
2030	250	226	477
2031	264	241	505
2032	277	254	532
2033	290	267	557
2034	302	279	581
2035	313	289	602
2036	322	299	621
2037	329	309	638
2038	335	317	652
2039	338	323	662
2040	339	328	667
2041	339	335	673
2042	339	339	678
2043	339	343	682
2044	339	343	682
2045	339	343	682
2046	339	345	684
2047	339	345	684
2048	339	345	684
2049	339	353	692
2050	339	353	692

32. Resource Need (Updated)

The Company's updated resource capacity need (Base Load Forecast) is provided below.

Table 2.14-14: Resource Capacity Need Forecast with Base Load Forecast

Year	2023	2024	2025	2026	2027	2028	2029	2030
CAPACITY NEED (MW)	**183**	**388**	**398**	**433**	**840**	**1,556**	**1,802**	**1,880**

As required by Paragraph 166 of Decision No. C22-0459, the Company's updated Loads and Resources table is provided below.

Table 2.12-1: Public Service Summer Loads & Resources Table

PSCo Summer L&R Table (MW)	2023	2024	2025	2026	2027	2028	2029	2030
Owned Coal	1,655	1,655	1,655	773	773	675	500	500
Purchased Coal	-	-	-	-	-	-	-	-
Total Coal-Fired Generation	**1,655**	**1,655**	**1,655**	**773**	**773**	**675**	**500**	**500**
Owned Gas Steam	310	310	310	815	815	505	505	505
Owned Gas Combined Cycle	1,914	1,914	1,914	1,914	1,914	1,914	1,914	1,914
Purchased Gas Combined Cycle	299	51	51	-	-	-	-	-
Owned Gas Combustion Turbine	1,065	1,065	1,065	1,065	894	894	894	894
Purchased Gas Combustion Turbine	756	756	756	730	457	236	236	236
Total Gas-Fired Generation	**4,344**	**4,096**	**4,096**	**4,525**	**4,080**	**3,549**	**3,549**	**3,549**
Owned Storage	275	275	275	275	275	275	275	275
Purchased Storage	136	136	136	136	136	136	136	136
Purchased Biomass	3	-	-	-	-	-	-	-
Owned Hydro	14	14	14	14	14	13	13	13
Purchased Hydro	18	18	17	17	9	-	-	-
Owned Solar	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Purchased Solar	576	609	606	603	600	594	591	588
Purchased BTM Solar	139	155	172	185	197	208	221	231
Purchased Community Solar	59	87	112	122	148	193	193	206
Owned Wind	147	147	147	147	147	147	147	147
Purchased Wind	401	401	401	393	383	316	316	313
Firm Transmission Import	-	-	-	-	-	-	-	-
Total Renewable/Other Generation	**1,770**	**1,844**	**1,882**	**1,894**	**1,911**	**1,884**	**1,894**	**1,911**
TOTAL ACCREDITED CAPACITY	**7,769**	**7,595**	**7,632**	**7,192**	**6,764**	**6,109**	**5,943**	**5,960**
Native Load Forecast - Fall2022	7,140	7,195	7,259	6,990	7,066	7,165	7,279	7,402
Demand Response	(516)	(538)	(563)	(597)	(631)	(679)	(725)	(767)
FIRM OBLIGATION LOAD	**6,624**	**6,657**	**6,696**	**6,393**	**6,435**	**6,486**	**6,554**	**6,635**
Target Planning Reserve Margin	1,279	1,278	1,286	1,221	1,158	1,168	1,180	1,194
IREA & HCEA Backup Reserves	48	48	48	11	11	11	11	11
TOTAL PLANNING RESERVE MARGIN TARGET	**1,327**	**1,326**	**1,334**	**1,232**	**1,169**	**1,178**	**1,191**	**1,205**
Actual Reserve Margin	1,144	938	936	800	329	(378)	(611)	(675)
CAPACITY POSITION: LONG/(SHORT)	**(183)**	**(388)**	**(398)**	**(433)**	**(840)**	**(1,556)**	**(1,802)**	**(1,880)**

A comparison of this updated Loads and Resources forecast to the most recent Loads and Resources forecast provided in Proceeding No. 22V-0388E as Figure 2 of the Verified Petition filed on September 2, 2022 and subsequently cited in the Joint Statement of Position, filed November 21, 2022, is shown below:

UPDATED PSCo CAPACITY POSITION (MW)

		2022	2023	2024	2025	2026	2027	2028	2029	2030
Docket 22V-0388E	**CAPACITY POSITION: LONG/(SHORT)**	**24**	**(49)**	**(270)**	**(348)**	**(429)**	**(933)**	**(1,767)**	**(2,086)**	**(2,231)**
	Load Forecast	15	(45)	(21)	1	35	76	103	131	168
	Demand Response	(31)	(45)	(23)	2	11	45	93	139	161
	Reserves	(3)	(17)	(8)	1	9	22	35	49	59
	Total Load Forecast & Reserve Changes	(18)	(107)	(52)	4	55	142	231	319	388
	Gas CC	(1)	(1)	-	-	-	-	-	-	-
	Gas CT	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
	Storage	-	-	(30)	(30)	(30)	(30)	(30)	(30)	(30)
	Solar	-	-	(48)	(48)	(47)	(47)	(47)	(47)	(46)
	Solar BTM	23	18	29	34	36	36	36	36	36
	Solar Community	(39)	(43)	(16)	(9)	(16)	(7)	22	7	5
	Total Resource Changes	(19)	(27)	(66)	(54)	(59)	(49)	(21)	(35)	(37)
Phase II	**CAPACITY POSITION: LONG/(SHORT)**	**(13)**	**(183)**	**(388)**	**(398)**	**(433)**	**(840)**	**(1,556)**	**(1,802)**	**(1,880)**
	DELTA	*(37)*	*(134)*	*(118)*	*(50)*	*(4)*	*93*	*211*	*284*	*351*

Key updates for the Phase II Loads and Resources forecast include: (1) updating the load forecast to the most recent vintage and assumptions as described in Section 28; (2) updating the DSM and Demand Response forecast as described in Section 11; (3) updating the Distributed Energy Forecasts as described in Section 30; and (4) incorporating the best information currently available to the Company that the Front-Range Midway project will most likely not proceed to construction and in-service.

33. Market Purchases and Sales Carbon Rate (No Change)

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.

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 CO2 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

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	-	-

34. Generic Resources Cost and Performance (Updated)

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).[5]

Generic resources serve multiple purposes in the Phase II ERP:

- Generic solar, wind, 4-hour duration battery storage, and gas-fired thermal resources will be available to the EnCompass model when creating the locked tail during the post-RAP periods, and
- Will be available to the model for resource optimization in 2029 and 2030 (for purposes of the "safe harbor" demonstration as contemplated in the Updated Non-Unanimous Partial Settlement Agreement).

For portfolio selection in the Phase II competitive acquisition, generic resource options in 2023-2028 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 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 2021 NREL Annual Technology Baseline ("ATB").[6] 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 II modeling, the battery generic was represented using a 50 MW size/block and an assumed 365-round trip cycles per year. An assumption of a 30% capital cost reduction from the 2021 NREL ATB costs was assumed to reflect impacts of the Inflation Reduction Act ("IRA") through 2037. This adjustment was made consistent with the Company's Phase I modeling approach.

[5] Grid upgrade costs are not included in the generic costs presented; grid upgrade costs are site-specific.
[6] Available at: https://atb.nrel.gov/electricity/2021/data

Wind Generic

Generic costs for a 200 MW land-based wind generic were obtained from the 2021 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 2.14-32 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-year book life. 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 in the IRA following the release of the 2021 ATB, projects with in-service dates through 2037 were modeled with: (1) a 100% PTC and (2) Debt Fraction, WACC Nominal and WACC Real values set to 2024 values, consistent with Paragraph 217 of Decision No. C22-0459 and Paragraph 92 of Decision No. C22-0559.

Solar Generic

Generic costs for a 100 MW PV utility solar generic were obtained from the 2021 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 2.14-32 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. The following adjustments were made to the base ATB model:

- Annual NCF was adjusted to match a Colorado resource at 28%,
- 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 in the IRA following the release of the 2021 ATB, projects with in-service dates through 2037 were modeled with: (1) a 30% ITC, and (2) Debt Fraction, WACC Nominal and WACC Real set to 2023 values consistent with Paragraph 217 of Decision No. C22-0459 and Paragraph 92 of Decision No. C22-0559.

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	25	25	25	25
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
2022	$7.62	$9.70	$14.21	$12.26
2023	7.75	9.87	14.48	12.49
2024	7.88	10.05	14.74	12.72
2025	8.02	10.23	15.02	12.95
2026	8.16	10.42	15.29	13.19
2027	8.30	10.60	15.58	13.44
2028	8.44	10.80	15.87	13.69
2029	8.59	10.99	16.16	13.94
2030	8.74	11.19	16.46	14.20
2031	8.89	11.39	16.77	14.46
2032	9.04	11.60	17.08	14.73
2033	9.20	11.81	17.40	15.01
2034	9.36	12.03	17.73	15.29
2035	9.53	12.25	18.06	15.57
2036	9.70	12.47	18.40	15.86
2037	9.87	12.70	18.74	16.16
2038	10.04	12.94	19.10	16.46
2039	10.22	13.17	19.46	16.77
2040	10.40	13.42	19.82	17.09
2041	10.59	13.67	20.20	17.41
2042	10.78	13.92	20.58	17.74
2043	10.97	14.18	20.97	18.07
2044	11.17	14.44	21.37	18.42
2045	11.37	14.71	21.77	18.76
2046	11.58	14.98	22.18	19.12
2047	11.78	15.26	22.61	19.48
2048	12.00	15.55	23.04	19.85
2049	12.22	15.84	23.47	20.23
2050	12.44	16.13	23.92	20.61
2051	12.66	16.43	24.38	21.01
2052	12.89	16.74	24.84	21.41
2053	13.13	17.06	25.32	21.81
2054	13.37	17.38	25.80	22.23
2055	13.62	17.70	26.30	22.66

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.

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
2022	$ 1,300	$ 1,330	$39.28	$18.43	$8.99
2023	1,270	1,310	38.78	17.94	9.54
2024	1,230	1,290	38.28	17.46	9.21
2025	1,190	1,260	37.69	16.97	8.87
2026	1,140	1,240	37.30	16.39	8.77
2027	1,100	1,220	36.81	15.81	8.66
2028	1,050	1,190	36.33	15.13	8.54
2029	1,000	1,160	35.75	14.46	8.42
2030	940	1,130	35.18	13.78	8.29
2031	950	1,140	35.71	13.81	8.30
2032	960	1,150	36.24	13.74	8.30
2033	980	1,170	36.69	13.78	8.30
2034	990	1,180	37.23	13.72	8.29
2035	1,000	1,190	37.78	13.76	8.27
2036	1,010	1,200	38.34	13.70	8.36
2037	1,020	1,210	38.90	13.65	8.40
2038	1,030	1,220	43.76	36.30	10.06
2039	1,040	1,230	44.34	36.75	10.09
2040	1,050	1,240	45.01	37.20	10.10
2041	1,060	1,250	45.59	37.66	10.11
2042	1,070	1,260	46.28	38.12	10.12
2043	1,080	1,270	46.88	38.49	10.12
2044	1,090	1,280	47.58	38.95	10.11
2045	1,100	1,290	48.28	39.43	10.10
2046	1,110	1,310	48.89	39.90	10.08
2047	1,120	1,320	49.61	40.38	10.05
2048	1,130	1,330	50.33	40.86	10.01
2049	1,140	1,340	50.97	41.34	9.96
2050	1,150	1,350	51.70	41.83	9.90
2051	1,160	1,360	52.30	42.20	9.90
2052	1,170	1,370	52.90	42.70	9.90
2053	1,180	1,380	53.60	43.10	9.90
2054	1,190	1,390	54.30	43.60	9.90
2055	1,200	1,400	54.90	44.10	9.90

Notes

1) Capital costs are the NREL 2021 ATB Overnight Capital Costs inflated at 2%/yr from 2019 to the in-service year.

2) Levelized energy costs are the NREL 2021 ATB levelized energy costs calculated over the assumed book life inflated at 2%/yr from 2019 to the in-service year. Wind energy costs assume 100% PTC through 2037 and 0% thereafter. Solar energy costs assume 30% ITC through 2037 and 10% ITC thereafter. Wind and solar energy costs assume a $250/kW transmission adder for all years.

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 2019 to the in-service year. The calculation also assumes that the battery qualifies for a 30% ITC through 2037.

Attachment A - Updated Storage ELCC Study Report

ASTRAPÉ CONSULTING
innovation in electric system planning

PSCo Effective Load Carrying Capability Assessment

Final Report

11/8/2022

PREPARED FOR

Public Service Company of Colorado ("PSCo")

PREPARED BY

Kevin Carden
Cole Benson
Astrapé Consulting

Contents

EXECUTIVE SUMMARY

Astrapé Consulting was engaged by Public Service Company of Colorado (PSCo) to use SERVM (Strategic Energy Risk Valuation Model) to analyze the effective load carrying capability (ELCC) of the following energy storage resources listed in Table 1.

Table 1: Results Summary

Duration	Capacity (MW)	Average ELCC	Incremental ELCC
2-Hour	125	95.6%	95.6%
2-Hour	250	91.3%	87.0%
2-Hour	500	83.4%	75.5%
2-Hour	1,000	69.4%	55.4%
2-Hour	2,000	49.1%	28.8%
2-Hour	3,000	39.0%	18.8%
4-Hour	125	97.1%	97.1%
4-Hour	250	94.3%	91.5%
4-Hour	500	88.9%	83.5%
4-Hour	1,000	79.0%	69.1%
4-Hour	2,000	62.3%	45.6%
4-Hour	3,000	50.0%	25.4%
8-Hour	125	97.3%	97.3%
8-Hour	250	95.2%	93.1%
8-Hour	500	91.2%	87.2%
8-Hour	1,000	83.7%	76.2%
8-Hour	2,000	70.4%	57.1%
8-Hour	3,000	59.8%	38.6%

INPUT SUMMARY AND METHODS

The energy storage resources were modeled with an 86% cycle efficiency, a 1% maintenance rate, a 5% forced outage rate, and they were dispatched in a manner to preserve reliability. The ELCCs provided are relative to a dispatchable resource which also has a 5% forced outage rate and is assumed to received 100% capacity accreditation. This is appropriate since PSCo's reserve margin target is based on installed capacity.

The study utilized 2014-2019 historical load and renewable profiles provided by PSCo along with the following 2030 resource mix listed in Table 2.

Table 2: 2030 Resource Mix

Unit Category	Capacity (MW)
PPA CC	327
PPA SC	989
PSC CC	1,836
PSC Coal	1,529
PSC SC	805
Hydro	87
Distributed Solar	1,820
PPA Solar	2,524
Solar	222
PPA Wind	3,774
PSC Wind	1,350
Wind	100
Battery Storage	275
DR	605
Hydro	87
Total	**17,194**

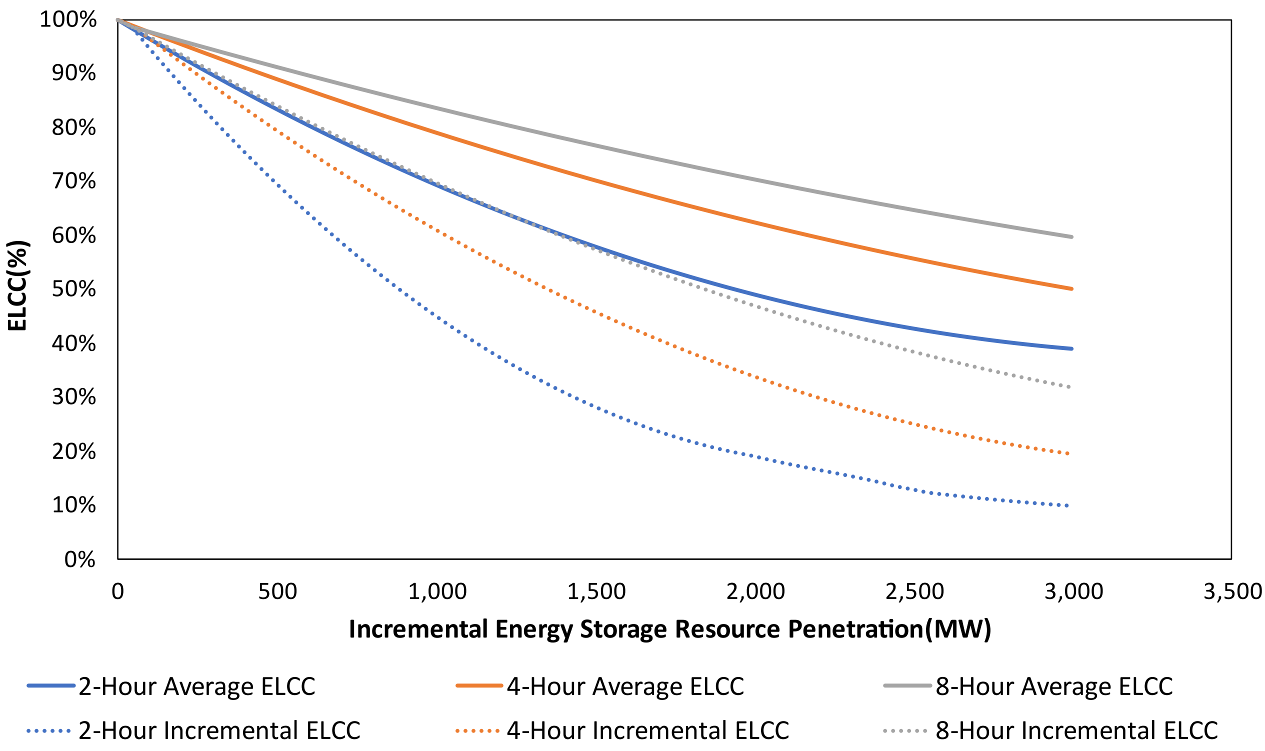
The base 2030 PSCo system was then calibrated to 0.1 LOLE by adding perfect capacity; this assumption/procedure is consistent with that from the PRM study conducted for PSCo. The energy storage resource was then added to the system and perfect capacity was removed until reliability returned to 0.1 LOLE. The ratio of the capacity removed to the capacity of the energy storage resource is the ELCC of the resource.

Dispatchable energy-limited resources are simulated consistent with their projected operation. Batteries and PSH are operated with a primary objective of supplying reliability, but also economically shifting load from high load periods to low load periods on non-constrained days. DR resources are modeled as emergency resources that are dispatched after all other dispatchable resources are committed. The current analysis also respects this emergency dispatch order.

RESULTS

Figure 1 below show the Average and Incremental ELCC of the 2-hour, 4-hour, and 8-hour energy storage resources as the penetration increases.

Figure 1: Average and Incremental ELCC Using 0.1 LOLE Metric



In addition to running the study where perfect capacity was removed until the LOLE returned to 0.1 LOLE, an additional run was performed where perfect capacity was removed until the total Expected Unserved Energy (EUE) returned to the amount seen in the 0.1 base case.[1] Figure 2 below shows the Average and Incremental ELCC of the 2-hour, 4-hour, and 8-hour energy storage resources as the incremental energy storage penetration increases in the additional EUE at 0.1 LOLE as a metric run. Figure 3 and Figure 4 below show the comparisons of Average and Incremental ELCC using both LOLE and EUE at 0.1 LOLE as the reliability metrics.

[1] Evolving best practices in resource adequacy include additional risk metrics such as EUE as opposed to a single focus on a LOLE target of 0.1.

Figure 2: Average and Incremental ELCC Using EUE at 0.1 LOLE Metric

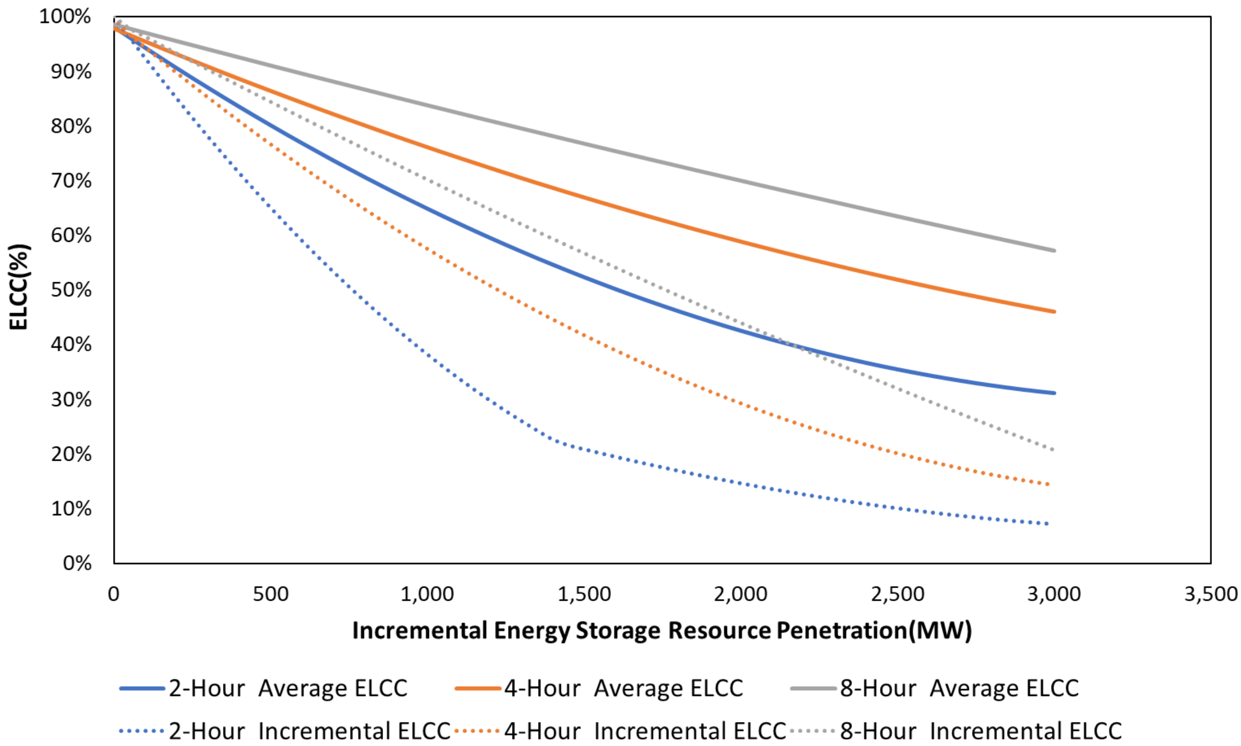


Figure 3: Average ELCC Using 0.1 LOLE and EUE at 0.1 Metrics

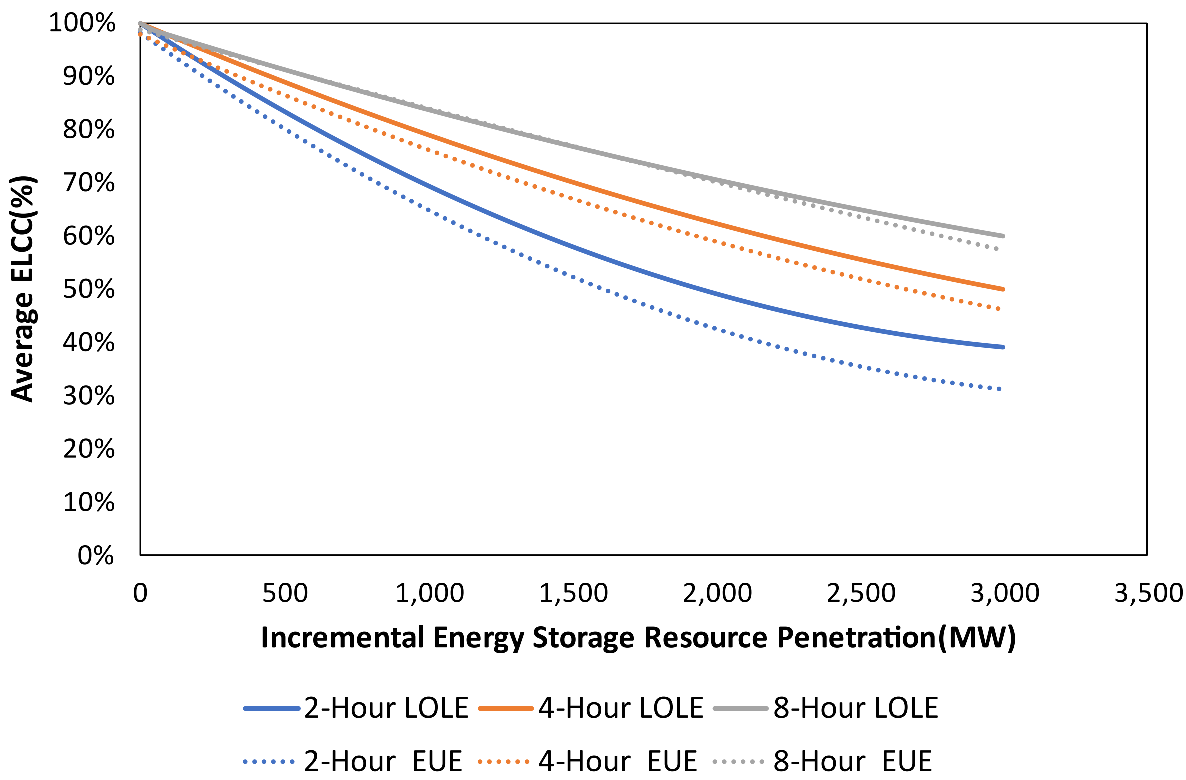
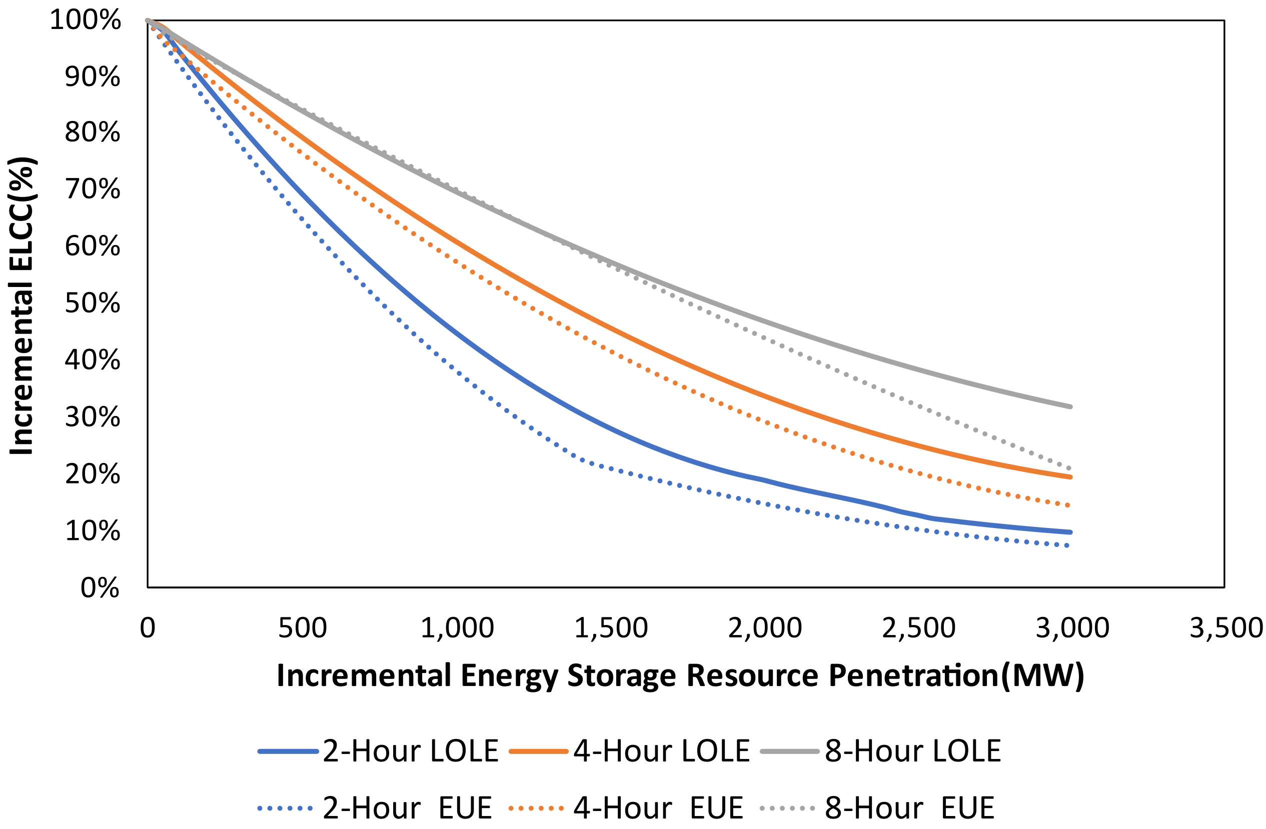
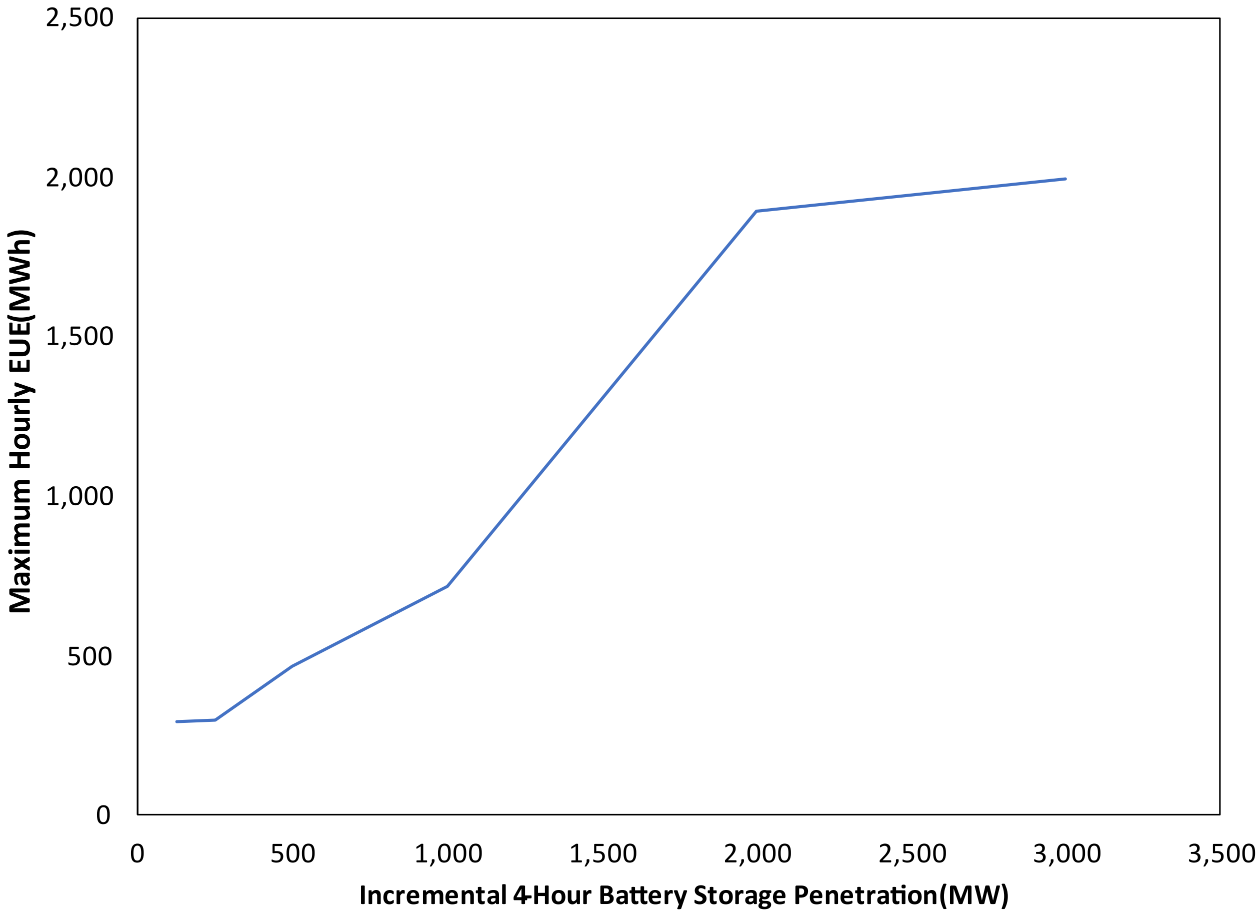


Figure 4: Incremental ELCC Using 0.1 LOLE and EUE at 0.1 Metrics



As the penetration of short duration battery storage increases, adequate capacity is maintained to be compliant with the 0.1 LOLE target. Even though the frequency of events remains the same, the larger penetration of short duration batteries leads to increased hourly EUE during these events as shown below in Figure 5. This is consistent with the findings in Figure 3 and Figure 4 where utilizing the EUE seen at 0.1 LOLE as the reliability metric results in a lower Average and Marginal ELCC for the higher penetrations of battery storage. Further, since the ELCC metric is produced from the weighted average simulations, it does not fully reflect the extreme jump in maximum hourly EUE shown in Figure 5. With 2,000 MW of incremental batteries, and with the system still at 0.1 LOLE, the largest hourly EUE is over 5 times larger than a system with 50 MW of incremental batteries. So, a system with incremental CT capacity and a system with incremental battery capacity could both meet the 0.1 LOLE requirement, but the system with higher battery penetration would be exposed to much larger hourly EUE events.

Figure 5: Maximum Hourly EUE as Function of 4-hr Battery Penetration



RESULTS TABLE

Table 3: Results

Duration	Capacity (MW)	Average ELCC	Incremental ELCC
2-Hour	125	95.6%	95.6%
2-Hour	250	91.3%	87.0%
2-Hour	500	83.4%	75.5%
2-Hour	1,000	69.4%	55.4%
2-Hour	2,000	49.1%	28.8%
2-Hour	3,000	39.0%	18.8%
4-Hour	125	97.1%	97.1%
4-Hour	250	94.3%	91.5%
4-Hour	500	88.9%	83.5%
4-Hour	1,000	79.0%	69.1%
4-Hour	2,000	62.3%	45.6%
4-Hour	3,000	50.0%	25.4%
8-Hour	125	97.3%	97.3%
8-Hour	250	95.2%	93.1%
8-Hour	500	91.2%	87.2%
8-Hour	1,000	83.7%	76.2%
8-Hour	2,000	70.4%	57.1%
8-Hour	3,000	59.8%	38.6%

APPENDIX

Table 4: Average ELCC (LOLE Method)

Incremental Capacity (MW)	2-Hour	4-Hour	8-Hour
50	98%	99%	99%
100	96%	98%	98%
150	95%	97%	97%
200	93%	95%	96%
250	91%	94%	95%
300	90%	93%	94%
350	88%	92%	94%
400	86%	91%	93%
450	85%	90%	92%
500	83%	89%	91%
550	82%	88%	90%
600	80%	87%	90%
650	79%	86%	89%
700	77%	85%	88%
750	76%	84%	87%
800	75%	83%	87%
850	73%	82%	86%
900	72%	81%	85%
950	71%	80%	84%
1,000	69%	79%	84%
1,050	68%	78%	83%
1,100	67%	77%	82%
1,150	66%	76%	82%
1,200	65%	75%	81%
1,250	63%	74%	80%
1,300	62%	74%	79%
1,350	61%	73%	79%
1,400	60%	72%	78%
1,450	59%	71%	77%
1,500	58%	70%	77%
1,550	57%	69%	76%
1,600	56%	68%	75%
1,650	55%	68%	75%
1,700	54%	67%	74%
1,750	53%	66%	74%
1,800	52%	65%	73%
1,850	51%	65%	72%
1,900	51%	64%	72%
1,950	50%	63%	71%
2,000	49%	62%	70%

2,050	48%	62%	70%
2,100	48%	61%	69%
2,150	47%	60%	69%
2,200	46%	60%	68%
2,250	46%	59%	68%
2,300	45%	58%	67%
2,350	44%	58%	66%
2,400	44%	57%	66%
2,450	43%	56%	65%
2,500	43%	56%	65%
2,550	42%	55%	64%
2,600	42%	54%	64%
2,650	41%	54%	63%
2,700	41%	53%	63%
2,750	41%	53%	62%
2,800	40%	52%	62%
2,850	40%	52%	61%
2,900	40%	51%	61%
2,950	39%	50%	60%
3,000	39%	50%	60%

Table 5: Incremental ELCC (LOLE Method)

Incremental Capacity (MW)	2-Hour	4-Hour	8-Hour
50	98%	99%	99%
100	95%	97%	97%
150	91%	94%	95%
200	88%	92%	94%
250	85%	90%	92%
300	81%	88%	90%
350	78%	86%	89%
400	75%	84%	87%
450	72%	81%	86%
500	70%	79%	84%
550	67%	77%	83%
600	64%	76%	81%
650	61%	74%	80%
700	59%	72%	78%
750	56%	70%	77%
800	54%	68%	75%
850	52%	66%	74%
900	49%	64%	73%
950	47%	63%	71%
1,000	45%	61%	70%

1,050	43%	59%	69%
1,100	41%	58%	67%
1,150	39%	56%	66%
1,200	37%	55%	65%
1,250	36%	53%	63%
1,300	34%	52%	62%
1,350	32%	50%	61%
1,400	31%	49%	60%
1,450	29%	47%	59%
1,500	28%	46%	57%
1,550	27%	44%	56%
1,600	26%	43%	55%
1,650	25%	42%	54%
1,700	24%	41%	53%
1,750	23%	39%	52%
1,800	22%	38%	51%
1,850	21%	37%	50%
1,900	20%	36%	49%
1,950	20%	35%	48%
2,000	19%	34%	47%
2,050	18%	33%	46%
2,100	18%	32%	45%
2,150	17%	31%	44%
2,200	16%	30%	43%
2,250	16%	29%	43%
2,300	15%	28%	42%
2,350	15%	27%	41%
2,400	14%	27%	40%
2,450	13%	26%	39%
2,500	13%	25%	38%
2,550	12%	24%	38%
2,600	12%	24%	37%
2,650	11%	23%	36%
2,700	11%	22%	36%
2,750	11%	22%	35%
2,800	11%	21%	34%
2,850	10%	21%	34%
2,900	10%	20%	33%
2,950	10%	20%	32%
3,000	10%	19%	32%

Table 6: Average ELCC (EUE Method)

Incremental Capacity (MW)	2-Hour	4-Hour	8-Hour
50	96%	97%	98%
100	94%	95%	97%
150	92%	94%	96%
200	91%	93%	96%
250	89%	92%	95%
300	87%	91%	94%
350	85%	90%	93%
400	83%	89%	93%
450	82%	88%	92%
500	80%	86%	91%
550	78%	85%	90%
600	77%	84%	90%
650	75%	83%	89%
700	74%	82%	88%
750	72%	81%	87%
800	71%	80%	87%
850	69%	79%	86%
900	68%	78%	85%
950	66%	77%	85%
1,000	65%	76%	84%
1,050	63%	75%	83%
1,100	62%	74%	82%
1,150	61%	73%	82%
1,200	60%	72%	81%
1,250	58%	71%	80%
1,300	57%	70%	80%
1,350	56%	70%	79%
1,400	55%	69%	78%
1,450	53%	68%	77%
1,500	52%	67%	77%
1,550	51%	66%	76%
1,600	50%	65%	75%
1,650	49%	64%	75%
1,700	48%	64%	74%
1,750	47%	63%	73%
1,800	46%	62%	73%
1,850	45%	61%	72%
1,900	44%	60%	71%
1,950	43%	60%	71%
2,000	43%	59%	70%
2,050	42%	58%	69%

2,100	41%	57%	69%
2,150	40%	57%	68%
2,200	39%	56%	67%
2,250	39%	55%	67%
2,300	38%	55%	66%
2,350	37%	54%	65%
2,400	37%	53%	65%
2,450	36%	53%	64%
2,500	35%	52%	63%
2,550	35%	51%	63%
2,600	34%	51%	62%
2,650	34%	50%	62%
2,700	33%	49%	61%
2,750	33%	49%	60%
2,800	33%	48%	60%
2,850	32%	48%	59%
2,900	32%	47%	58%
2,950	31%	47%	58%
3,000	31%	46%	57%

Table 7: Incremental ELCC (EUE Method)

Incremental Capacity (MW)	2-Hour	4-Hour	8-Hour
0	100%	100%	100%
50	96%	97%	98%
100	92%	94%	96%
150	89%	92%	95%
200	85%	90%	93%
250	81%	87%	92%
300	78%	85%	90%
350	75%	83%	89%
400	71%	81%	87%
450	68%	79%	86%
500	65%	77%	84%
550	62%	75%	83%
600	59%	73%	81%
650	56%	71%	80%
700	53%	69%	79%
750	51%	67%	77%
800	48%	65%	76%
850	45%	63%	74%
900	43%	61%	73%
950	41%	59%	72%

1,000	38%	58%	70%
1,050	36%	56%	69%
1,100	34%	54%	67%
1,150	32%	52%	66%
1,200	30%	51%	65%
1,250	28%	49%	63%
1,300	26%	48%	62%
1,350	24%	46%	61%
1,400	23%	45%	59%
1,450	22%	43%	58%
1,500	21%	42%	57%
1,550	20%	40%	55%
1,600	19%	39%	54%
1,650	19%	38%	53%
1,700	18%	36%	52%
1,750	18%	35%	50%
1,800	17%	34%	49%
1,850	16%	33%	48%
1,900	16%	31%	47%
1,950	15%	30%	45%
2,000	15%	29%	44%
2,050	14%	28%	43%
2,100	14%	27%	42%
2,150	13%	26%	40%
2,200	13%	25%	39%
2,250	12%	24%	38%
2,300	12%	23%	37%
2,350	11%	23%	36%
2,400	11%	22%	34%
2,450	10%	21%	33%
2,500	10%	20%	32%
2,550	10%	19%	31%
2,600	9%	19%	30%
2,650	9%	18%	29%
2,700	9%	17%	27%
2,750	8%	17%	26%
2,800	8%	16%	25%
2,850	8%	16%	24%
2,900	8%	15%	23%
2,950	7%	15%	22%
3,000	7%	14%	21%

Astrapé had previously analyzed the ELCC of storage resources for PSCo and found a declining ELCC for energy-limited resources as shown in **Table 8**.

Table 8: 2020 ELCC Study Results

	2021	2023	2026	2030
	Capacity (MW)			
All Solar	908	2207	3226	4508
Wind	4124	4124	4624	5124
PSH + DR + Hybrid	848	1136	1155	1180
	Raw ELCC (MW)			
All Solar	629	838	1,237	1,515
Wind	585	742	820	966
PSH + DR + Hybrid	728	1,028	1,137	1,122
Sum	1,942	2,608	3,194	3,603
Portfolio	1,802	2,286	2,633	2,915
Diversity Benefit	-140	-322	-561	-688
	Allocated ELCC (MW)			
All Solar	547	699	1010	1233
Wind	551	665	682	778
PSH + DR + Hybrid	704	922	941	904
Sum	1,802	2,286	2,633	2,915
Portfolio	1,802	2,286	2,633	2,915
	ELCC (%)			
All Solar	60.2%	31.7%	31.3%	27.4%
Wind	13.4%	16.1%	14.7%	15.2%
PSH + DR + Hybrid	83.0%	81.2%	81.5%	76.6%
Combined ELCC	30.6%	30.6%	29.2%	27.0%

The 2020 study analyzed the reliability contribution of all non-dispatchable and energy-limited resources including solar, wind, PSH, DR, and hybrid solar and battery projects projected through 2030. Dispatchable energy-limited resources are simulated consistent with their projected operation. Batteries and PSH are operated with a primary objective of supplying reliability, but also economically shifting load from high load periods to low load periods on non-constrained days. DR resources are modeled as emergency resources that are dispatched after all other dispatchable resources are committed. The current analysis also respects this emergency dispatch order.

In the 2020 analysis, each group of technologies[2] was analyzed independently by removing one technology group at a time as well as analyzed as a portfolio for each study year. The sum of the ELCCs for the independent analysis was greater than the portfolio ELCC. This demonstrated a synergy between resource classes in that each resource was only able to contribute as much reliability value as demonstrated because the other technologies were already in the system. As an example, in 2030, the last in ELCC values summed to 3,603 MW while the portfolio ELCC provided only 2,903 MW. This 700 MW of synergy was then allocated to each technology group proportionally. The 2020 study showed that after the allocation process described, the ELCC of the PSH+DR+Hybrid resource tranche on the PSCo system was 76.6% in 2030. As a point of comparison, the results shown in this latest study show that the 4-Hour 500 MW battery storage level, which is incremental to the storage included in the 2020 study, has an average ELCC of 89%. While the ELCC of energy limited and non-dispatchable resources generally decline with penetration, changing the composition of the portfolio can affect this trend as can be seen in the variable wind ELCC in Table 8. Notwithstanding these effects, storage additions incremental to the portfolio identified in 2030 would be expected to monotonically decline and the increase in ELCC from 76.6% to 89% is surprising. The increase in incremental storage ELCC is driven by two effects: the method used to allocate diversity and unique limitations on the energy-limited portfolio. The diversity that drove the 2030 portfolio value to be much lower than last-in technology-specific ELCCs was allocated equally across all three technology classes. However, most of the diversity value was driven by wind and solar synergy. The large wind portfolio shifted the net load peak to earlier in the day so that solar could contribute more significantly to reliability. This means that solar and wind ELCCs are overstated in Table 8 and storage ELCC is understated. Secondarily, some unique constraints on the utilization of DR and PSH[3], as well as max combined output constraints on solar hybrid facilities limited the reliability value of storage resources.

Given that the only constraint modeled on incremental storage resources in this analysis was a duration limitation, any unique constraint on future resources should be considered when determining their ELCC. These constraints could include paired renewable charging limitations, daily or annual cycle limitations, depth of discharge constraints, interconnection limits, and others.

[2]Wind, solar, and energy-limited resources were the respective technology groups with energy-limited resources comprising pumped storage hydro, demand response and the battery portion of hybrid resources.

[3] Certain demand response programs' availability was limited to specific hours of each day. PSH is required to maintain a minimum dispatch which limits its ability to serve A/S. Batteries can serve A/S while dispatched around a baseline of 0 MW.