Agenda 17-24; Item No. 2A Draft Order for discussion at agenda

THIS ORDER IS NOT A FINAL ORDER AND MAY BE SUBSTANTIALLY REVISED PRIOR TO ENTRY OF A FINAL ORDER BY THE PUBLIC UTILITIES COMMISSION OF NEVADA

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of Sierra Pacific Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.	Docket No. 24-02026
Application of Sierra Pacific Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of gas customers and for relief properly related thereto.	Docket No. 24-02027

At a special session of the Public Utilities Commission of Nevada, held at its offices on September 17, 2024.

PRESENT: Chair Hayley Williamson
Commissioner Tammy Cordova
Commissioner Randy J. Brown
Assistant Commission Secretary Trisha Osborne

[PROPOSED] ORDER

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The Public Utilities Commission of Nevada ("Commission") makes the following findings and conclusions:

I. INTRODUCTION

On February 23, 2024, Sierra Pacific Power Company d/b/a NV Energy ("Sierra") filed with the Commission an application, designated as Docket No. 24-02026 ("Application in Docket No. 24-02026"), for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.

On February 23, 2024, Sierra filed with the Commission an application, designated as Docket No. 24-02027 ("Application in Docket No. 24-02027" and together with the Application in Docket No. 24-02026, the "Applications"), for authority to adjust its annual revenue requirement for general rates charged to all classes of gas customers and for relief properly related thereto.

II. SUMMARY

The Commission grants in part Sierra's Applications as modified by this Order.

III. PROCEDURAL HISTORY

- On February 23, 2024, Sierra filed the Applications.
- Sierra filed the Applications pursuant to the Nevada Revised Statues ("NRS") and the Nevada Administrative Code ("NAC") Chapters 703 and 704, including, but not limited to, NRS 704.100, NRS 704.110, NAC 703.2201 through 703.2481, NAC 703.535, NAC 703.2715, NAC 704.6502 through NAC 704.6546, NAC 704.655 through NAC 704.665, NAC 704.673 through 704.680, and Assembly Bill 524 (2023). Pursuant to NRS 703.196 and NAC 703.527 et seq., Sierra requests that certain material in the Applications receive confidential treatment.
- The Regulatory Operations Staff of the Commission ("Staff") participates as a matter of right pursuant to NRS 703.301.
- On March 4, 2024, the Nevada Bureau of Consumer Protection ("BCP") filed a Notice of Intent to Intervene pursuant to Chapter 228 of the NRS in Docket Nos. 24-02026 and 24-02027.
- On March 7, 2024, the Commission issued a Notice of Application for Authority to Adjust Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and Notice of Prehearing Conference in Docket No. 24-02026 and a Notice of Application for Authority to Adjust Annual Revenue Requirement for General Rates Charged to All Classes of Gas Customers and Notice of Prehearing Conference in Docket No. 24-02027.
- On March 12, 2024, the Commission issued a corrected Notice of Application and Notice of

Prehearing Conference in Docket No. 24-02027.

- On March 15, 2024, Walmart Inc. ("Walmart") filed a Petition for Leave to Intervene ("PLTI") in Docket No. 24-02026.

- On March 21, 2024, Google LLC ("Google") filed a PLTI in Docket No. 24-02026.

- On March 22, 2024, the Smart Energy Alliance ("SEA") filed a PLTI in Docket No. 24-02026.

- On March 25, 2024, EP Minerals, LLC; Heavenly Valley, Limited Partnership; Nevada Cement Company; Nugget Sparks, LLC d/b/a Nugget Casino Resort; Premier Magnesia, LLC; Prime Healthcare Services – Reno, LLC d/b/a Saint Mary's Regional Medical Center, Inc.; and Renown Health (collectively, "Northern Nevada Industrial Electric Users" or "NNIEU") filed a PLTI in Docket No. 24-02026.

- On March 27, 2024, the Solar Energy Industries Association ("SEIA") filed a PLTI in Docket No. 24-02026; Nevadans for Clean Affordable Reliable Energy ("NCARE"), on behalf of members of Western Resource Advocates ("WRA") and the Southwest Energy Efficiency Project ("SWEEP"), filed a PLTI in Docket No. 24-02026; Peppermill Casinos Inc. ("Peppermill") filed a PLTI in Docket No. 24-02026; and Caesars Enterprise Services, LLC ("Caesars") filed a PLTI in Docket No. 24-02026.

- On March 29, 2024, the Presiding Officer held a prehearing conference. Sierra, Staff, BCP, Walmart, Google, SEA, NNIEU, SEIA, NCARE, Peppermill, and Caesars made appearances. A procedural schedule, PLTIs, consolidating dockets, discovery procedures, and a consumer session were discussed.

- On April 4, 2024, SEIA filed an amendment to its PLTI.

- On April 8, 2024, the Commission issued a Notice of Hearing and an Order granting the PLTIs of Walmart, Google, SEA, NNIEU, SEIA, NCARE, Peppermill, and Caesars.

- On April 11, 2024, the Commission issued a Corrected Notice of Hearing.

- On April 17, 2024, the Presiding Officer issued a Procedural Order consolidating Docket Nos. 24-02026 and 24-02027 for hearing purposes; establishing that the hearings in these dockets would occur in three phases: (1) Cost of Capital; (2) Revenue Requirement; and (3) Rate Design; adopting a procedural schedule; and adopting a discovery process.

- On April 18, 2024, Sierra filed an errata to its Applications.

- On April 22, 2024, Sierra filed its cost of capital certification filing.

- On April 30, 2024, the Presiding Officer issued Procedural Order No. 2, order seeking clarification from Sierra on certain issues.

- On May 10, 2024, Sierra filed a comment in response to Procedural Order No. 2.

- On May 13, 2024, Sierra filed its revenue requirement certification filing. On this same day, the Commission issued a Notice of Consumer Sessions.

- On May 17, 2024, Sierra filed an amendment to its revenue requirement certification filing.

- On May 20, 2024, the Presiding Officer issued Procedural Order No. 3, seeking clarification from Sierra on certain issues in the Applications.

- On May 21, 2024, Caesars, Peppermill, SEA, Staff, BCP, and Walmart filed direct testimony for the cost of capital phase.

- On May 24, 2024, Sierra filed its rate design certification filing.

- On June 4, 2024, the Commission held two consumer sessions.

- On June 5, 2024, the Presiding Officer issued Procedural Order No. 4, establishing hearing procedures for the cost of capital phase.

- On June 7, 2024, Sierra filed rebuttal testimony for the cost of capital phase.

- On June 11, 2024, NCARE filed a motionrequesting to be excused from the first two phases of the hearing and to appear remotely for the first phase of hearing for the purposes of memorializing NCARE's request to be excused. On this same day, NNIEU filed a letter noting that NNIEU does not intend to participate in the cost of capital phase of the hearing and accordingly requests to be excused from appearing at the cost of capital phase.

- On June 13, 2024, the Commission held a third consumer session.

- On June 14, 2024, SEA, Caesars, and Peppermill jointly filed a motion requesting remote appearance for witness Lance D. Kaufman. On this same day, Sierra filed a response to Procedural Order No. 3, and filed two errata – one for its revenue requirement certification, and one for its rebuttal testimony.

- On June 18, 2024, BCP filed an errata to its direct testimony for the cost of capital phase of the hearing.

- On June 24, 2024, the Presiding Officer issued Procedural Order No. 5, granting remote appearances for the witness of SEA, Caesars, and Peppermill and also excusing NCARE and NNIEU from participation in the cost of capital phase of the hearings.

- On June 26, 2024, the cost of capital phase of the hearings was held. Sierra, Staff, BCP, Walmart, SEA, Peppermill, and Caesars made appearances. NNIEU, NCARE, SEIA, and Google were excused from the cost of capital phase of the hearings.

- On July 3, 2024, Sierra filed its rebuttal testimony for the revenue requirement phase of the hearing.

- On July 5, 2024, Staff, SEA, NNIEU, Peppermill, Walmart, and BCP filed their direct testimony for the rate design phase of the hearing.

- On July 10, 2024, the Commission issued Procedural Order No. 6, establishing hearing procedures for the revenue requirement phase. On this same day, Sierra filed a motion requesting remote appearances for the revenue requirement phase of hearing.

- On July 11, 2024, BCP and SEA each filed a motion requesting remote appearances for the revenue requirement phase of hearing. On this same day, NNIEU and Walmart filed a request to be excused from the revenue requirement phase of hearing.

- On July 12, 2024, SEIA filed a motion ("SEIA's Motion") requesting the remote appearance of a witness for the revenue requirement phase of hearing.

- On July 15, 2024, the Presiding Officer issued Procedural Order No. 7, seeking additional information related to the disclosure of confidential materials.

- On July 16, 2024, the Presiding Officer issued Procedural Order No. 8, granting remote appearances for certain witnesses and excusing Walmart and NNIEU from the revenue requirement phase of the hearings.

- On July 17, 2024, Sierra filed a motion requesting a remote appearance for a witness. On this same day, BCP filed executable work papers.

- On July 18, 2024, Staff filed supplemental testimony.

- On July 19, 2024, Sierra filed its rate design testimony.

- On July 22, 2024, Sierra filed supplemental revenue requirement testimony.

- On July 22, 2024, Sierra filed a response to Procedural Order No. 7. That same day, the revenue requirement phase of the hearings was held. Sierra, SEA, SEIA, Caesars, Google, Peppermill, BCP, and Staff made appearances.

- On July 25, 2024, Walmart, SEA, and NCARE all filed motions for remote witness appearances in the rate design phase of the hearings.

- On July 29, 2024, NNIEU filed a motion for its witness to appear remotely in the rate design phase of the hearings.

- On July 31, 2024, Peppermill and SEIA filed motions for remote witness appearances in the rate design phase of the hearings.

- On August 1, 2024, Staff filed an errata to its rate design testimony.
- On August 5, 2024, BCP filed a motion for its witness to appear remotely in the rate design phase of the hearings. On this same day, Staff filed an errata to its revenue requirement testimony, and the Presiding Officer issued Procedural Order No. 9, establishing hearing procedures for the rate design phase.
- On August 6, 2024, the Presiding Officer issued Procedural Order No. 10, granting remote appearances for the witnesses of Walmart, SEA, NCARE, NNIEU, SEIA, Peppermill, and BCP.
- On August 8, 2024, Staff filed an errata to its rate design testimony.
- On August 9, 2024, NNIEU filed executable workpapers for its rate design testimony.
- On August 12, 2024, the rate design phase of the hearings was held. Walmart, Google, SEA, NCARE, NNIEU, Peppermill, SEIA, Caesars, BCP, and Staff all made appearances.
- On August 13, 2024, SEIA filed an errata to its rate design testimony.
- On August 14, 2024, NCARE filed executable workpapers for its rate design testimony.
- On August 20, 2024, Sierra, SEA, NNIEU, NCARE, SEIA, Peppermill, BCP, and Caesars all filed legal briefs. On this same day, Google, Walmart, and Staff filed letters indicating they would not be filing legal briefs.
- On August 27, 2024, SEIA, Sierra, Staff, BCP, and SEA all filed reply briefs. On this same day, Google and Walmart filed letters indicating they would not be filing reply briefs.

IV. COST OF CAPITAL

Sierra's Position

1. In its Application in Docket No. 24-02026, Sierra requests an increase in its authorized rate of return ("ROR") for its electric operations from the current rate of 7.14 percent to a proposed rate of 7.95 percent based on the cost of debt, cost of equity, and capital structure. (Ex. 101 at 7.) In its Application in Docket No. 24-02027, Sierra requests an increase in its authorized ROR for its gas operations from the current rate of 5.75 percent to a proposed rate of 7.95 percent based on the cost of debt, cost of equity, and capital structure. (Ex. 112 at 7.) For both its gas and electric operations, Sierra requests an increase in its return on equity ("ROE")

from 9.5 percent to 10.4 percent, and a capital structure of 44.6 percent debt and 55.4 percent equity. (*Id.*; Ex. 101 at 7.) Through its Certification filing, Sierra requests that the Commission establish an ROR for its gas and electric operations, reflecting its February 29, 2024, capital structure of 44.81 percent debt and 55.19 percent equity, a cost of debt of 4.89 percent, and an authorized ROE of 10.40 percent – resulting in an ROR equal to 7.93 percent. (Ex. 120 at 11.)

2. Sierra requests an ROE of 10.40 percent. (Ex. 134 at 85; Ex. 135 at 85.) Sierra states that, to arrive at its requested ROE, it applied several traditional estimation methodologies to a proxy group of comparable utilities, including the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and the Bond Yield Risk Premium ("BYRP" or "Risk Premium"). (Ex. 134 at 2; Ex. 135 at 2.) Sierra explains that it utilized four primary proxy groups in its analyses: (1) a proxy group of electric utilities; (2) a proxy group of natural gas utilities; (3) a combination of the proxy groups of electric and natural gas utilities ("Combined Gas and Electric"); and (4) a proxy group of utilities that own both electric and natural gas operations ("Combination Utilities"). (Ex. 134 at 3; Ex. 135 at 3.)

3. The results of Sierra's analyses are summarized in the following tables:

Natural Gas Only Proxy Group			
Constant Growth DCF - Mean			
	Mean Low	**Mean**	**Mean High**
30-Day Average	9.89%	10.84%	12.02%
90-Day Average	9.72%	10.67%	11.85%
180-Day Average	9.53%	10.48%	11.66%
Constant Growth DCF - Median			
	Median Low	**Median**	**Median High**
30-Day Average	10.03%	10.30%	11.92%
90-Day Average	9.97%	10.24%	11.70%
180-Day Average	9.95%	10.22%	11.38%
CAPM			

	Current 30-Day Avg. Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.47%	11.43%	11.37%
Bloomberg Beta	10.72%	10.65%	10.56%
Long-term Avg. Beta	10.43%	10.35%	10.25%
ECAPM			
	Current 30-Day Avg. Treasury Bond Yield	**Near-Term Blue Chip Forecast Yield**	**Long-Term Blue Chip Forecast Yield**
Value Line Beta	11.74%	11.71%	11.67%
Bloomberg Beta	11.18%	11.13%	11.06%
Long-term Avg. Beta	10.96%	10.90%	10.83%

(Ex. 134 at 86; Ex. 135 at 86.)

Electric Only Proxy Group			
Constant Growth DCF - Mean			
	Mean Low	**Mean**	**Mean High**
30-Day Average	8.94%	10.15%	11.28%
90-Day Average	8.88%	10.09%	11.22%
180-Day Average	8.69%	9.90%	11.03%
Constant Growth DCF - Median			
	Median Low	**Median**	**Median High**
30-Day Average	8.77%	10.08%	11.24%
90-Day Average	8.69%	9.95%	11.21%
180-Day Average	8.58%	9.76%	10.02%
CAPM			
	Current 30-Day Avg. Treasury Bond Yield	**Near-Term Blue Chip Forecast Yield**	**Long-Term Blue Chip Forecast Yield**
Value Line Beta	11.71%	11.68%	11.64%
Bloomberg Beta	10.92%	10.86%	10.78%
Long-term Avg. Beta	10.59%	10.51%	10.41%
ECAPM			
	Current 30-Day Avg. Treasury Bond Yield	**Near-Term Blue Chip Forecast Yield**	**Long-Term Blue Chip Forecast Yield**
Value Line Beta	11.92%	11.90%	11.87%
Bloomberg Beta	11.33%	11.28%	11.22%
Long-term Avg. Beta	11.08%	11.02%	10.95%

(Ex. 134 at 86-87; Ex. 135 at 86-87.)

Combination Utilities Proxy Group			
Constant Growth DCF - Mean			
	Mean Low	**Mean**	**Mean High**
30-Day Average	9.62%	10.25%	10.87%
90-Day Average	9.59%	10.22%	10.84%
180-Day Average	9.41%	10.05%	10.66%
Constant Growth DCF - Median			
	Median Low	**Median**	**Median High**
30-Day Average	9.58%	9.89%	10.51%
90-Day Average	9.64%	9.95%	10.46%
180-Day Average	9.46%	9.76%	10.27%
CAPM			
	Current 30-Day Avg. Treasury Bond Yield	**Near-Term Blue Chip Forecast Yield**	**Long-Term Blue Chip Forecast Yield**
Value Line Beta	11.43%	11.39%	11.33%
Bloomberg Beta	10.71%	10.64%	10.55%
Long-term Avg. Beta	10.25%	10.17%	10.05%
ECAPM			
	Current 30-Day Avg. Treasury Bond Yield	**Near-Term Blue Chip Forecast Yield**	**Long-Term Blue Chip Forecast Yield**
Value Line Beta	11.71%	11.68%	11.64%
Bloomberg Beta	11.17%	11.12%	11.05%
Long-term Avg. Beta	10.83%	10.76%	10.68%

(Ex. 134 at 87; Ex. 135 at 87.)

Combined Gas and Electric Proxy Group			
Constant Growth DCF - Mean			
	Mean Low	**Mean**	**Mean High**
30-Day Average	9.16%	10.31%	11.45%
90-Day Average	9.07%	10.22%	11.37%
180-Day Average	8.88%	10.03%	11.17%
Constant Growth DCF - Median			
	Median Low	**Median**	**Median High**
30-Day Average	9.37%	10.09%	11.29%

90-Day Average	9.03%	10.04%	11.26%
180-Day Average	8.77%	9.89%	11.05%
CAPM			
	Current 30-Day Avg. Treasury Bond Yield	**Near-Term Blue Chip Forecast Yield**	**Long-Term Blue Chip Forecast Yield**
Value Line Beta	11.65%	11.62%	11.58%
Bloomberg Beta	10.88%	10.81%	10.73%
Long-term Avg. Beta	10.55%	10.48%	10.38%
ECAPM			
	Current 30-Day Avg. Treasury Bond Yield	**Near-Term Blue Chip Forecast Yield**	**Long-Term Blue Chip Forecast Yield**
Value Line Beta	11.88%	11.85%	11.82%
Bloomberg Beta	11.30%	11.25%	11.19%
Long-term Avg. Beta	11.05%	11.00%	10.92%

(Ex. 134 at 87-88; Ex. 135 at 87-88.)

Bond Yield Risk Premium			
	Current 30-Day Avg. Treasury Bond Yield	**Near-Term Blue Chip Forecast Yield**	**Long-Term Blue Chip Forecast Yield**
Results - electric	10.68%	10.55%	10.38%
Results - natural gas	10.51%	10.38%	10.22%
Results - combination electric and natural gas	10.26%	10.42%	10.55%

(Ex. 134 at 88; Ex. 135 at 88.)

4. Sierra represents that it has historically provided separate capital structures for its gas and electric operations with corresponding disaggregated debt costs for the determination of separate ROEs for gas and electric operations. (Ex. 136 at 14; Ex. 137 at 14.) Nonetheless, Sierra notes that, from a liquidity management perspective, Sierra does not financially manage its gas and electric operations separately and Sierra is instead viewed as a single financial entity for the purpose of determining capital needs in support of both gas and electric operations. (*Id.*) Therefore, Sierra asserts that its gas and electric operations should be consolidated for the

purposes of determining Sierra's capital investments and return on capital investments. (Ex. 136 at 14-15; Ex. 137 at 14-15.)

Walmart's Position

5. Walmart argues that the Commission should thoroughly and carefully consider the impact on customers when examining the requested revenue requirement and ROE, in addition to all other facets of this case, to ensure that any increase in Sierra's rates is the minimum necessary to provide safe, adequate, and reliable service while also providing Sierra the opportunity to recover its reasonable and prudent costs and earn a reasonable return on its investment. (Ex. 600 at 3-4.) Walmart recommends that the Commission closely examine Sierra's proposed revenue requirement and ROE increases in light of the customer impact of the resulting revenue requirement, recent rate case ROEs approved by the Commission, and recent ROEs approved by other commissions nationwide. (*Id.* at 4.)

6. Walmart states that—if using Sierra's proposed rate base, cost of debt, and capital structure—the impact of changing Sierra's currently-approved ROE of 9.5 percent to Sierra's proposed ROE of 10.4 percent is approximately $14.4 million. (*Id.* at 6.)

7. Walmart notes that the Commission has issued orders with stated ROEs in two dockets since 2021 with an average approved ROE of 9.5 percent. (*Id.*) Walmart states, therefore, that Sierra's proposed 10.4-percent ROE is counter to recent Commission actions regarding ROE. (*Id.* at 7.)

8. Walmart notes that, according to S&P Global Market Intelligence, the average of the 115 reported electric utility ROEs authorized by commissions to investor-owned utilities in 2021, 2022, 2023, and so far in 2024, is 9.5 percent. (*Id.*) The range of reported authorized electric ROEs for the period is 7.36 percent to 11.45 percent, and the median authorized electric

ROE is 9.5 percent. (*Id.*) Accordingly, Walmart reasons that Sierra's proposal of an ROE of 10.4 percent is counter to broader electric industry trends. (*Id.*)

9. Walmart notes that the average authorized ROE for vertically-integrated utilities in 2021 was 9.54 percent, 9.60 percent in 2022, 9.71 percent in 2023, and 9.67 percent so far in 2024. (*Id.* at 8.) Walmart therefore argues that Sierra's proposed total ROE of 10.4 percent is counter to broader electric industry trends and would be the fourth-highest approved ROE (out of 84) since 2021. (*Id.*) Walmart notes that the difference in revenue requirement between the proposed 10.4-percent ROE and a 9.62-percent ROE is approximately $12.5 million. (*Id.* at 8-9.) Walmart states that, while decisions of other state regulatory commissions are not binding on this Commission, recently-authorized ROEs in other jurisdictions can provide a general gauge of reasonableness for the various cost-of-equity analyses presented in this case. (*Id.* at 9.)

SEA, Caesars, and Peppermill's Position

10. SEA, Caesars, and Peppermill (collectively, "SCP") recommend that the Commission adopt a 50-percent equity and 50-percent debt hypothetical capital structure, a 9.25-percent cost of equity, a 4.89-percent cost of debt, and a 7.07-percent weighted average cost of capital. (Ex. 700 at 1-2.)

11. SCP recommends a 9.25-percent cost of equity based on the application of the DCF model, the CAPM, and the ECAPM. (*Id.* at 2.) SCP states that the primary difference between Sierra's approach to ROE and SCP's approach to ROE is that SCP's focus is on the ROE required by Sierra to attract capital, and Sierra favors forecasts of expected returns. (*Id.* at 2-3.) SCP states that the returns for equity markets are expected to be lower in the future than they have been historically, citing forecasts from Charles Schwab for large and small company stocks to be 6.2 and 6.3 percent on average over the next ten years. (*Id.* at 3.)

12. SCP states that its cost of equity analysis shows that near-term investors can expect returns in the range of 8.5 to 9.5 percent, which is above expected market returns. (*Id.* at 4.) However, the current ROE of 9.5 percent is inconsistent with expectations about long-run returns. (*Id.*) SCP recommends that the Commission begin moving returns toward long-run expectations now to smooth the transition to lower expected equity returns. (*Id.*) SCP states that in addition to providing proper signals to investors, its recommendation considers the equity ratio of the proxy group. (*Id.* at 4.) SCP argues that a 9.5-percent ROE might be reasonable for a company with 42-percent equity, but it is too high for a company with 50-percent equity, as proposed by SCP. (*Id.*) SCP argues that should the Commission approve of Sierra's requested equity ratio of 55.19 percent, that equity ratio should be paired with an ROE of 8.85 percent, as the ROE reflects the lower risk associated with Sierra's excessive equity ratio. (*Id.*)

13. SCP recommends that the Commission gradually reduce Sierra's ROE to prevent investors from holding ill-conceived forecasts about authorized ROEs exceeding necessary ROEs and receiving shocks when such forecasts turn out to be incorrect. (*Id.* at 6). SCP states that it is important for investors to have accurate expectations about regulatory treatment. (*Id.*)

14. SCP states that its recommended ROE is consistent with the authorized ROE for many financially sound utilities, allows for a smooth transition to a lower ROE by preventing investors from having too-high expectations, and allows Sierra investors to obtain returns in excess of those necessary for investments of comparable risk. (*Id* at 7.)

15. SCP states that the impact of its ROE recommendation is a reduction to Sierra's revenue requirement of $17.6 million, and its capital structure recommendation reduces Sierra's revenue requirement by $7.8 million, which together reduces Sierra's revenue requirement by $25.3 million relative to the certification filing. (*Id.*)

16. SCP recommends a 9.25-percent ROE based on the application of the DCF model, the three-stage DCF model, the CAPM, and the ECAPM. (*Id.*) SCP states that 9.25 percent is slightly above the midpoint of the 8.5- to 9.5-percent ROE and is consistent with a 50-50 capital structure. (*Id.* at 8.) SCP argues that should the Commission approve Sierra's requested equity ratio of 55 percent, the Commission should also reduce the ROE to 8.85 percent. (*Id.*)

17. SCP states that its DCF models estimate an ROE range from 8.92 to 9.54 percent, which is derived from Sierra's combination proxy group and a growth rate that reflects average growth over the short and long run. (*Id.* at 12.) SCP argues that Sierra's constant growth model assumes that 1-to-5-year growth forecasts continue indefinitely, which is implausible. (*Id.*) SCP states that its growth rate is more accurate because it assumes a growth rate of 1 to 30 years, which balances near- and long-term expectations. (*Id.* at 13.)

18. SCP provides two long-term growth scenarios, one based on the long-term forecast for US gross domestic product, and the other based on 30-year treasury bond yields. (*Id.*) The table below summarizes the results of these models:

Constant Growth DCF		
30 Day Average	8.92%	9.51%
90 Day Average	8.99%	9.48%
180 Day Average	8.95%	9.51%
Average	8.95%	9.50%
Three Stage DCF		
30-Day Average	9.21%	9.54%
90-Day Average	9.17%	9.50%

180-Day Average	8.97%	9.30%
Average	9.12%	9.45%

(*Id.* at Table LK-3.)

19. SCP states that its CAPM models estimate an ROE range from 8.32 percent to 9.17 percent, which differ from Sierra's CAPM models as the two respected beta inputs are different, and Sierra's risk premium is too high due to its reliance on a biased selection of market forecasts. (*Id.* at 14-15.) SCP states that Sierra's reliance on a beta of one is flawed, and that leads to grossly excessive forecast bias in both the near and long term and tends to over-inflate a utility's cost of capital. (*Id.* at 15, 20.)

20. SCP argues that the utility industry's average beta is 0.672, significantly lower than Sierra's beta of one. (*Id.* at 26.) SCP states that its recommended betas reduce the estimation of Sierra's cost of capital relative to Sierra's estimate. (*Id.*)

21. SCP states that Sierra's higher forecasted risk premiums are higher than other available estimates of risk premium due to its use of a DCF model comprised of S&P 500 growth forecasts, which are limited to S&P firms with growth forecasts between 0 and 20 percent. (*Id.*) SCP argues that these limits are arbitrary and biased because they do not include companies with negative growth forecasts. (*Id.* at 27.) SCP argues that this leads to a risk premium for Sierra 60 percent higher than the average of other institutions. (*Id.*) SCP states that Sierra's models also assume consistent 20-percent growth for all firms in the model, which is unsustainable. (*Id.* at 28.)

22. SCP states that market surveys of investors and other experts, plus historical market data, reveal Sierra's proposed equity risk premium is unreasonably high. (*Id.*) SCP argues that historically, risk premiums for companies similar to Sierra have an equity risk

premium of 4.47 to 5.13 percent. (*Id.* at 30.) SCP states that the best way to decipher forward risk is to look at the implied equity premium of the trailing 12 months. (*Id.*) SCP states that the January 2024 trailing 12-month implied equity risk premium is 4.6 percent, substantially lower than Sierra's forecast of 7.7 percent. (*Id.*)

23. SCP states that its ECAPM models estimate an ROE range from 8.81 percent to 9.75 percent. SCP does not recommend placing weight behind this model because it contains questionable assumptions. (*Id.* at 32.)

24. SCP states that market conditions are largely irrelevant when determining whether cost of equity should be increased or decreased, and as such, SCP is not persuaded by Sierra's arguments regarding market conditions in relation to the cost of equity. (*Id.* at 32-33.)

25. SCP states that Sierra has had no problems attracting capital, and the fact that Sierra is proposing to increase capital spending indicates an investor appetite for Sierra's existing ROE. (*Id.* at 33.) SCP believes that Sierra might be arguing for overcapitalization to increase net income, known as the Averch-Johnson effect. (*Id.*)

26. SCP argues that Sierra's effort to increase its equity ratio indicates that its current ROE is excessive, and that it is using biased methodologies to shift costs to customers. (*Id.* at 35.) SCP states that Sierra's preference for new generation to be company-owned is an indication of overcapitalization to increase net income. (*Id.*)

27. SCP disagrees with Sierra's assertion that the Sierra Solar project should be considered when establishing cost of capital. (*Id.* at 36.) SCP states that Sierra could have secured a solar power purchase agreement ("PPA") without exposing its own equity to risk, and that Sierra's decision to invest equity in the project is a manifestation of the Averch-Johnson effect. (*Id.*) SCP argues that while the Sierra Solar project increases Sierra's risk, that increase in

risk is self-imposed. (*Id.*) SCP argues that increasing returns when the company intentionally increases financial risk would cause an upward spiral in ROE and cost increases to customers. (*Id.*)

28. SCP states that the DCF, CAPM, and ECAPM models result in a broad range of ROE estimates, but they all overlap to one degree or another within the range of 8.5 to 9.5 percent. (*Id.* at 37.) SCP reiterates its recommendation for an ROE of 9.25 percent, which reduces Sierra's revenue requirement by $17.6 million relative to the certification filing. (*Id.*)

29. SCP recommends the use of a hypothetical capital structure of 50-percent common equity to 50-percent debt, based on a midpoint between Berkshire Hathaway Energy's ("BHE") capital structure and Sierra's certification capital structure. (*Id.* at 38.)

30. SCP argues that Sierra is misrepresenting the capital structure of the proxy group, as Sierra's equity ratio is more than 10 percent higher than the average actual equity ratio. (*Id.*) SCP further states that the use of BHE's capital structure would be inappropriate as ROE estimates reflect the risk of the holding company, not the operating company. (*Id.* at 40.)

31. SCP states that a hypothetical capital structure of 50-percent equity and 50-percent debt decreases the cost of equity by 0.8 to 1.4 percent per 10 percent increase in equity ratio, and Sierra's requested equity ratio is 5 percent higher than the proxy group's holding company. (*Id.*) SCP states that if the Commission finds in favor of SCP's cost of capital models, but selects Sierra's proposed equity ratio, the ROE should be reduced to 8.85 percent. (*Id.*)

32. SCP states that a capital structure that is weighted at over 55 percent equity is unreasonable and not in line with other similarly situated utilities, and it would result in an unnecessary cost burden to customers. (*Id.* at 43.) SCP believes that there is no risk of a credit downgrade as far as capital structure goes, so nothing that the Commission does in this part of

the case will result in one. (*Id.*) SCP believes its proposed capital structure would reduce Sierra's revenue requirement by $7.8 million relative to its certification filing, thus saving customers money. (*Id.* at 44.)

33. SCP concludes by proposing a reduced weighted average cost of capital for Sierra from 7.93 percent to 7.08 percent. (*Id.*)

BCP's Position

34. BCP provides a summary of its cost-of-equity estimates for Sierra's gas operations in the following table:

Cost of Equity Estimates

Model	Range	Midpoint
DCF	9.64% - 9.71%	9.68%
Two-Stage DCF	9.46% - 9.77%	9.62%
CAPM	9.22% - 9.28%	9.25%
ECAPM	9.45% - 9.50%	9.47%
Bond Risk Premium	9.97%	9.97%
Reasonable Range of All Models	9.40% - 9.7%	9.55%
Risk Adjustment	-0.20%	-0.20%
Recommended Range and Estimate	9.20% - 9.50%	9.35%

(Ex. 400 at 4.)

35. Based on the foregoing analyses, BCP recommends a 9.35 percent ROE for Sierra's gas operations. (*Id.* at 7.) BCP explains, however, that if Sierra's requested 55.19-percent equity capital structure is adopted, the ROE should be adjusted (reduced) by 20 basis points for Sierra's lower financial risk. (*Id.* at 5.) BCP states that when the 9.35-percent ROE recommendation is combined with BCP's proposed capital structure of 55.19-percent equity and 44.19-percent debt, along with a 4.80-percent cost of long-term debt, it results in a recommended

overall weighted average return on rate base investment of 7.31 percent, which is consistent with current market capital costs in the utility industry and consistent with just and reasonable rates for consumers. (*Id.* at 7.)

36. BCP provides a summary of its cost-of-equity estimates for Sierra's electric operations in the following table:

Model	**Range**	**Midpoint**
DCF Model	9.86% - 9.88%	9.87%
Two-stage DCF	9.74% - 9.77%	9.76%
CAPM	9.63% - 9.83%	9.73%
ECAPM	9.76% - 9.91%	9.84%
Bond Risk Premium	10.27%	10.27%
Reasonable Range of All Models	9.70% - 9.90%	9.80%
Risk Adjustment	-0.30%	-0.30%
Recommended ROE	9.40% - 9.60%	9.50%

(*Id.* at 6.)

37. Based on these foregoing analyses, BCP recommends a 9.50-percent ROE for Sierra's electric operations in this case. (*Id.* at 4.) BCP explains, however, that if Sierra's requested 55.19-percent equity capital structure is adopted, the ROE should be adjusted (reduced) by 30 basis points for considerations of financial risks relative to the comparable risk of electric companies. (*Id.*) BCP states that when the 9.50-percent ROE recommendation is combined with BCP's proposed capital structure of 55.19-percent equity and 44.19-percent debt, it results in a recommended overall weighted average return on rate base investment of 7.44 percent, which is consistent with current market capital costs in the utility industry and consistent with just and reasonable rates for consumers. (*Id.* at 7.)

38. BCP recommends a consolidated (gas and electric) capital structure of 44.19 percent long-term debt capital, 0.63 percent customer deposits, and 55.19 percent equity capital, along with a downward financial risk adjustment for equity costs. (*Id.* at 7.)

39. BCP recommends a long-term debt cost for Sierra's gas operations of 4.80 percent, and it recommends that the Commission reject Sierra's proposed rate-base allocator for tax-exempt bonds. (*Id.* at 10.) BCP also recommends a long-term debt cost for Sierra's electric operations of 4.90 percent, and it recommends that the Commission reject Sierra's proposed rate-base allocator for tax-exempt bonds. (*Id.*)

40. BCP further recommends a customer-deposit cost rate of 5.24 percent, which is consistent with Sierra's request. (*Id.*) BCP recommends an overall cost of capital applied to rate-base investment of 7.44 percent for electric customers and an overall cost of capital applied to rate-base investment of 7.31 percent for gas customers. (*Id.*) BCP states that Sierra's cash flows and liquidity at these rates will increase over current levels. (*Id.*)

41. BCP argues that Sierra's proposed 7.93-percent overall cost of capital, gas and electric cost rates of 4.80 percent debt, and consolidated gas and electric 10.4-percent equity is excessive and should not be used. (*Id.* at 10-11.) BCP states that correcting Sierra's proposed consolidation of long-term debt costs and equity costs will eliminate cross-subsidization between electric and gas customers, and correcting the 10.4 percent return for equity shareholders avoids an overstatement of the required return on equity to attract equity capital. (*Id.* at 11.)

42. BCP notes that roughly 27 percent of Sierra's requested annual $95 million increase for electric customers is driven by requested changes in cost of capital, which makes capital costs a significant driver for the $95 million annual electric rate proposal. (*Id.* at 12.) BCP notes that another (smaller) cost driver is system investment, which has increased by about

$89 million, or four percent, over the last rate case. (*Id.*) BCP further notes that other cost-drivers include higher costs for day-to-day operations, increases in depreciation expenses, and increased staffing transition from COVID levels. (*Id.*)

43. BCP also notes that Sierra is projecting a revenue deficiency of about $11 million for its gas customers, and that Sierra's requested rate of return of 7.93 percent amounts to about $6 million of the annual $11 million request, or about 55 percent. (*Id.* at 13.) BCP therefore argues that cost of capital is a key cost-driver for the gas rate increase proposed (*Id.* at 14.)

44. BCP argues that while Sierra has filed gas and electric rate cases in the past, the main difference in the present case is that Sierra filed two separate cost-of-service analyses – one for electric customers and one for gas customers—while only one cost of capital for long-term debt (4.89 percent) and cost of equity (10.4 percent) has been filed. (*Id.* at 14-15.) BCP states that this consolidated cost of capital approach is not consistent with Sierra's past filings or consistent with the Commission's past decisions on cost of capital. (*Id.* at 15.)

45. BCP states that the last time Sierra filed a combined gas and electric rate case was Docket Nos. 16-06006 and 16-06007, and the authorized return on rate base was 6.65 percent, with an equity return of 9.6 percent, resulting in a 6.65-percent overall cost of capital. (*Id.* at 16.) BCP states that in the same consolidated proceeding, Sierra's cost of capital for its gas operations was 5.75 percent, with 9.5-percent ROE. (*Id.* at 17.) BCP states that Sierra's gas cost of long-term debt, along with a 5.75-percent cost of capital and a 9.50-percent cost of equity were all substantially below the authorized levels for Sierra's electric operations, with only the capital structure being the same for both electric and gas. (*Id.*)

46. BCP states that Sierra's 2013 consolidated gas and electric rate case filing (Docket Nos. 13-06002 and 13-06003) also resulted in Commission-approved lower long-term

debt costs, lower equity costs, and lower overall cost of capital for gas operations relative to the electric cost of capital. (*Id.* at 17-18.)

47. BCP states that Sierra has substantially increased the capital structure equity percentage 716 basis points from 48.03 percent in 2016 to 55.19 percent in the current proceeding, while also increasing long-term debt cost for gas customers from 2.30 percent to 4.89 percent. (*Id.* at 19.) BCP states that Sierra's proposed equity return has increased substantially for both gas (9.50 percent to 10.4 percent) and electric (9.50 percent to 10.40 percent) customers. (*Id.*)

48. BCP argues that Sierra's requested return on investment is overstated in light of current market capital cost, unsupported by its own analyses, and the requested capital structure of over a 55 percent equity ratio pushes shareholder profits even higher. (*Id.* at 20.) BCP further argues that Sierra is overstating the size of the base rate increase in this case, and that Sierra's decision to consolidate the equity and debt costs leads to substantial additional increases for gas customers. (*Id.*)

49. BCP cites to the *Bluefield*[1] and *Hope*[2] decisions issued by the United States Supreme Court as the basis for establishing rate of return. (*Id.* at 21.) BCP states that those cases established that a rate of return should be sufficient for maintaining financial integrity and capital attraction, and that a public utility is entitled to a return equal to that of investments of comparable risk. (*Id.*) BCP argues that it is the Commission's duty to ensure that rates are not excessive of actual costs or burdensome to the customer, while simultaneously being just and reasonable to the utility. (*Id.* at 22.)

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[1] *Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).
[2] *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1942).

50. BCP states that it favors the DCF methodology for estimating the cost of equity, while also employing the two-stage DCF to reflect different growth-rate assumptions. (*Id.* at 23.) BCP states that it has also employed the CAPM, ECAPM, and bond yield equity risk premium models to check the reasonableness of DCF results. (*Id.*)

51. BCP states that current capital market conditions reflect declining inflation, under a tighter monetary policy with higher federal funds rates, and higher interest rates set by the Federal Reserve. (*Id.* at 24.) BCP states that the Federal Reserve and the Federal Open Market Committee ("FOMC") noted in its May 1, 2024, meeting that inflation has eased over the past year but remains elevated. (*Id.* at 26.) BCP states that the FOMC expects inflation will average 2.4 percent for 2024, decline to 2.2 percent in 2025, and decline again to 2.0 percent in 2026. (*Id.* at 27.)

52. BCP argues that because interest rates are expected to decrease, other capital costs such as equity will also decrease, but they do not move in congruence with one another. (*Id.* at 28.) BCP argues that even if it is correct to conclude debt costs will decrease over the short-term, equity changes should be of significantly smaller magnitude. (*Id.* at 29.)

53. BCP expects interest rates to decrease before the end of 2024 and to continue to decline in 2025. (*Id.*) BCP favors the most current three-month average as the best approximation of interest rate levels, as it captures market expectations and trends of interest rates while avoiding any limited influences shorter durations may have on interest rates. (*Id.*)

54. BCP argues that capital costs remain low in comparison to historical levels, and that general economic data does not support substantially increasing capital costs. (*Id.* at 30.) BCP further argues that the average authorized ROE for gas and electric is around 9.6 percent, far lower than Sierra's proposed 10.4-percent ROE. (*Id.*)

55. BCP states that risks for Sierra are lower than the average electric and gas operation given cost-recovery through credit-supportive regulation and the proposed rate design increase to the fixed basic service charge. (*Id.* at 31.) BCP states that such an increase will result in an increased cash flow for Sierra, free from risks related to weather, economic conditions, or any other influence on an electricity charge, all while transferring risk to customers. (*Id.* at 32.)

56. BCP states that credit-rating agencies have weighed in on Sierra's rate mechanisms, with Standard and Poor's ("S&P") Credit Research Report designating Sierra as "lower risk." (*Id.* at 33.) BCP states that Moody's Investor Service ("Moody's") also views Sierra's regulatory framework as both traditional and supportive, and that the Commission's authorized returns for Sierra have also been credit-supportive. (*Id.*) BCP notes that Moody's did downgrade Sierra's outlook from "Stable" to "Negative" in February 2024, due to Sierra's substantial capital expansion program. (*Id.*) BCP also notes, however, that Sierra's parent company, Berkshire Hathaway Energy ("BHE"), has the ability to assist with financing these capital-heavy projects through equity infusions to maintain equity ratios and credit metrics. (*Id.*)

57. BCP states that Sierra can mitigate regulatory lag via the supportive regulatory process in Nevada and the timing of rate requests, and states that regulatory lag is built into the regulatory process to encourage the utility to control and monitor its costs. (*Id.* at 34.)

58. BCP argues that while Sierra does have a large new-facility construction program in place over the next few years, there is an expectation that cash-flow metrics will decline over the construction period until the facilities are included in rates. (*Id.* at 36.) BCP states that these two risks explain the Moody's downgrade described above, but given the temporary nature of increased construction costs, these risks may be lower than the average electric or gas operation with cost recovery through credit supportive regulation and the support of BHE ownership. (*Id.*)

59. BCP states that a higher equity return when combined with cost-recovery mechanisms can lead to excess profits and unreasonable rates, and that risk is addressed by these cost-recovery mechanisms. (*Id.*) BCP states that if risk is addressed by cost recovery mechanisms, a higher equity return authorization would overcompensate risk (*Id.*)

60. BCP states that it agrees with Sierra's selection of screening criteria for the comparable group analysis in this case, and that it employs the same 5-company gas utility group and the same 17-company electric group that Sierra has identified. (*Id.* at 37.)

61. BCP states that in its constant-growth DCF analysis, the gas utility comparable group mean and median results fall in a range of 9.64 percent to 9.71 percent, with about a 9.68-percent midpoint. (*Id.* at 44.) BCP states that in its constant-growth DCF analyses for the electric utility comparable group, mean and median results fall in a range of 9.86 percent to 9.88 percent, with a 9.87-percent midpoint. (*Id.*) BCP states that it also conducted a two-stage non-constant-growth DCF analysis and found that gas utility comparable group mean and median results indicate a cost-of-equity range of 9.46 percent to 9.77 percent, with a 9.62-percent midpoint. (*Id.* at 46.) BCP states that the two-stage non-constant-growth DCF analysis found the electric utility group mean and median results indicate a cost-of-equity range of 9.74 percent to 9.77 percent, with a 9.76-percent midpoint. (*Id.*)

62. BCP states that it performed a bond yield equity risk premium analysis to evaluate the risk/return differential between the authorized gas and electric utility ROE relative to 30-year U.S. Treasury bond yields for the period 1981 through 2023. (*Id.* at 52.) BCP states that the resulting risk premium range of results for the gas utility group is 9.97 percent, and the electric utility group is 10.27 percent. (*Id.*) BCP states that it performed CAPM analyses yielding an equity return range for the gas utility group of 9.22 percent to 9.28 percent, with a 9.25-percent

midpoint with the equity return range for the electric utility group of 9.63 percent to 9.83 percent, with a 9.73-percent midpoint. (*Id.* at 51.) BCP states that it also performed ECAPM analyses yielding an equity return range for gas utility groups of 9.45 percent to 9.50 percent, with a 9.47 percent midpoint. (*Id.* at 52.) BCP states that its ECAPM analyses yielding an equity return range for electric utility groups are 9.76 percent to 9.91 percent with a midpoint of 9.84 percent. (*Id.*)

63. BCP states that it has concerns regarding Sierra's proposed capital structure. (*Id.* at 56.) BCP is mainly concerned about the use of a single consolidated capital structure and resulting 7.93-percent rate of return to be earned on both gas and electric rate-base investment. (*Id.*) BCP notes that while the capital structure ratios for debt and equity have been historically the same for gas and electric, the debt and equity cost rates have been established independently and not consolidated, as proposed by Sierra. (*Id.*) BCP notes that under Sierra's consolidated approach, all bonds are allocated to gas and electric operations based on the respective rate-base allocator. (*Id.* at 57.)

64. BCP states that the rate-base allocator in this proceeding is 8.52 percent for gas operations and 91.48 percent for electric operations, meaning 8.52 percent of all outstanding bonds and the contractual interest obligations are assigned to gas operations, and 91.48 percent of bonds and their contractual costs are assigned to electric operations, assuring that the long-term debt costs are equal in this case, at 4.89 percent for both gas and electric. (*Id.*)

65. BCP argues that three tax-exempt bonds at issue—Washoe County Series 2016B, Washoe County Series 2016C, and Washoe County Series 2016F—totaling $165,230,000 should be allocated based on the historical allocation, which reflects the purpose of each of these bonds, and the projects developed from the original financing are still system assets, as the historical

allocator provides the simplicity that Sierra is asking for. (*Id.* at 60.) BCP recommends that tax-exempt debt be allocated employing the historical allocators, with gas at 4.80 percent and electric at 4.90 percent for long-term debt costs. (*Id.* at 61.)

66. BCP states that Sierra's proposed 55.19-percent equity ratio is higher than comparable gas and electric utilities' current authorized levels of equity, and that Sierra's financial risk is lower than comparable companies. (*Id.* at 62.)

67. BCP states that if the Commission accepts Sierra's proposed capital structure with 55.19-percent equity ratio, the equity return should be reduced to address Sierra's lower financial risk. (*Id.* at 64.) BCP states that the current average comparable electric utility equity ratio is 52.3 percent, and the current average comparable gas equity ratio is 53.59 percent, both of which are below Sierra's request. (*Id.*)

68. BCP recommends a capital structure of 55.19-percent equity and 44.81-percent debt for both Sierra electric and gas, but BCP employs different long-term debt rates and different equity costs for gas and electric, which reflect Sierra's respective costs and risks for gas and electric. (*Id.* at 66-67.) BCP recommends an overall cost of capital for gas of 7.31 percent, and a cost of capital for electric of 7.44 percent. (*Id.* at 67.)

69. BCP argues that based on the recent ratings reports from both Moody's and S&P, Sierra is not in danger of losing current credit ratings, and BCP's recommendations will not cause Sierra's financial integrity to diminish. (*Id.* at 69.)

70. BCP points out that Sierra's proposed equity ratio reflects a substantial upward increase in equity capital, which was accomplished by suspending dividends in 2022 and equity infusions of approximately $400 million by its parent company. (*Id.* at 55.) BCP notes that this increased equity ratio alone will result in approximately $8.35 million of added profits to

shareholders and cost consumers about $12.8 million in annual revenue requirement. (*Id.*) Accordingly, BCP recommends that the Commission deny Sierra's proposed equity ratio and maintain the 51.29-percent December 31, 2022, historical test-year end equity ratio in this case. (*Id.* at 56.) BCP provides that Sierra's proposed equity ratio substantially exceeds the comparable group equity average while Sierra's financial risk is less than the comparable group. (*Id.* at 59.)

71. BCP takes issue with Sierra's DCF analyses. (*Id.* at 69.) Particularly, BCP argues that it is inappropriate for Sierra to use wide-ranging model results rather than the current market conditions, business or financial risk considerations, or other specific risk considerations. (*Id.* at 70.) BCP is also concerned about a 10.4-percent return on equity for both Sierra's electric and gas operations, as gas operations have generally lower risks than vertically-integrated electric companies. (*Id.*) BCP argues that the DCF, CAPM, and ECAPM models used by Sierra only recommend the 10.4-percent equity return because none of their models considers risk factors. (*Id.* at 71.)

72. BCP argues that a 10.4-percent return on equity for Sierra is unreasonable because Sierra's own historical data and financial models demonstrate that a 10.4-percent return is overstated for both electric and gas operations. (*Id.* at 72.) BCP also notes that even with changes to interest rates and inflation, no regulatory authority in the country has authorized an equity return above 10 percent. (*Id.*) Also, interest rates and inflation are expected to decline going forward, which does not support Sierra's recommendation to increase the Sierra equity returns. (*Id.*)

73. BCP states that its recommendation of increasing equity ratio from 52 percent to 55.19 percent provides Sierra about $7.3 million of increased pre-tax cash flow annually on a $2.195-billion rate-base investment level. (*Id.* at 75.)

Staff's Position

74. Staff recommends that the Commission accept a capital structure in which the ratio of total debt to total capital is 47.60 percent and total equity to total capital is 52.40 percent. (Ex. 300 at 1.) Staff recommends that the Commission reject Sierra's proposal to use a consolidated cost of debt for Sierra's electric ("Sierra-E") division and Sierra's gas ("Sierra-G") division, while accepting Sierra's cost of debt at 4.90 percent for Sierra-E and 4.80 percent for Sierra G. (*Id.* at 1.) Staff recommends that the Commission adopt an allowed ROE of 9.50 percent, with a reasonable range of 9.20 percent to 9.90 percent for Sierra-E, and an allowed ROE of 9.40 percent with a reasonable range of 9.10 percent to 9.90 percent for Sierra-G, with a resulting ROR of 7.31 percent for Sierra-E and 7.21 percent for Sierra-G. (*Id.* at 1-2.)

75. Staff summarizes its recommendations in the following table:

	Fraction	**Cost of Capital**	**Weighted ROR**
Electric Division			
Total Debt	47.60%	4.90%	2.33%
Common Equity	52.40%	9.50%	4.98%
All Capital Sources	**100.00%**		**7.31%**
Gas Division			
Total Debt	47.60%	4.80%	2.28%
Common Equity	52.40%	9.40%	4.93%
All Capital Source	**100.00%**		**7.21%**

(Ex. 300 at 2.)

76. Staff states that Sierra is requesting the use of a consolidated capital structure for both its electric and gas divisions, and a capital structure of 44.81-percent debt and 55.19-percent total equity. (*Id.*) Staff states that Sierra is also requesting an ROE of 10.40 percent, 90 basis

points higher than its current ROE of 9.50 percent for both its electric and gas divisions, resulting in a requested ROR of 7.93 percent, which is 98 basis points higher than what the Commission authorized in December 2022 for Sierra-E and 218 basis points higher than what is authorized for Sierra-G. (*Id.* at 3.) Staff explains that this increase in the ROR comprises approximately $25.7 million of Sierra-E's overall $95-million requested increase, and approximately $7.6 million of Sierra-G's $11.1-million requested increase in this case. (*Id.*) Staff states that for Sierra-E, increases to the cost of debt comprise 22 basis points of the 98-basis-point increase, while the remaining 76 basis points of the increase to ROR are due to Sierra's requested increase to its authorized ROE. (*Id.*) Staff states that for Sierra-G, increases to the cost of debt comprise 99 basis points of the 216-basis-point increase, while the remaining 118 basis points are due to Sierra's requested increase to its authorized ROE. (*Id.* at 4.)

77. Staff summarizes its recommendations for Sierra's ROE in the following table:

Method	**Measure**	**Combination**	**Electric**	**Gas**	**E+G**
DCF (Constant Growth and Three-Stage)	Average	9.65%	9.77%	9.8%	9.79%
	Range	8.84% - 10.07%	9.08% - 10.12%	9.01% - 10.33%	9.07% - 10.15%
CAPM &ECAPM	Average	10.85%	10.85%	10.53%	10.79%
	Range	10.69% - 11.19%	10.55%- 11.18%	10.17% - 10.90%	10.48% - 11.13%
Allowed ROE/Bond Yield	Average	10.21% (E) 10.18% (G)	10.21%	10.18%	
Average		10.24%	10.28%	10.20%	10.26%
Average (excluding CAPM/ECAPM		9.93%	9.99%	10.03%	10.00%

(Ex. 300 at 5.)

78. Staff states that it has issues with Sierra's certified capital structure of 44.81 percent debt and 55.19 percent equity, with 44.19 percent long-term debt and 0.63 percent customer deposits. (*Id.* at 13.) First, Staff states that Sierra's equity ratio is significantly higher than the equity ratios of the proxy group companies, equity ratios awarded to gas and electric utility companies in the U.S., and equity ratios that have been previously authorized. (*Id.*) Also, Staff states that Sierra's equity ratio reflects several equity infusions and dividend payments that serve to balance its perceived requirements from credit rating agencies and impact on customer rates. (*Id.*) Staff notes that Sierra has been operating at a near-60 percent equity ratio since its general rate case in 2022. (*Id.*)

79. Staff states that Sierra's equity ratio is significantly higher than that of Staff's and Sierra's own proxy groups. (*Id.* at 14.) Staff summarizes Sierra's equity ratio as compared to Staff's proxy groups below:

	5-year Average	**2022**	**2023**
Sierra	56.4%	60.2%	62.2%
Proxy Group			
Combination	44.1%	44.3%	44.0%
Electric	44.9%	44.8%	44.2%
Gas	47.8%	46.4%	47.2%
Electric and Gas	45.4%	45.1%	44.8%

(Ex. 300 at 15.)

80. Staff additionally notes that S&P Global reported that the average authorized equity ratios in 2023 and 2022 were 51.15 percent and 50.36 percent respectively for electric utilities, and 52.45 percent and 51.38 percent, respectively, for gas utilities. (*Id.*) Staff further

notes that Sierra's own equity ratio for the certification period is about three to seven percent higher than equity ratios previously authorized by the Commission. (*Id.*)

81. Staff states that it does not have any issues with the specific equity contributions and dividends Sierra has issued and received, and it notes that such contributions and dividends were not common prior to Sierra's 2022 general rate case. (*Id.* at 17.) Staff argues that these actions show the extent to which Sierra can control its capital structure at any given time, for example by receiving $465 million in contributions in 2022 but issuing $400 million in debt and paying $100 million in dividends through September of 2023. (*Id.*) Staff notes that Moody's expects Sierra to receive in the near future over $1 billion in equity contributions from BHE. (*Id.*)

82. Staff recommends maintaining Sierra's equity ratio at 52.40 percent for several reasons – the previously-authorized equity ratios are much lower than the currently-requested one, Sierra's own forecasts of equity ratios for 2025-2027 are lower than the currently-requested one, the average authorized ratio of 2023 is 51.15 percent for electric utilities and 52.45 percent for gas utilities, and the average of all data points is more consistent with a 52.40-percent ratio. (*Id.*) Staff states that Sierra would not need to lower its equity ratio to match Staff's capital structure. (*Id.* at 19.)

83. Staff states that Sierra wishes to avoid a credit downgrade by estimating an additional cost of debt of $30 million over the next 30 years, which would increase Sierra's ROE by 0.1 percent. (*Id.*) Staff states that this results in an increased cost to ratepayers of $2.1 million every year for Sierra-E and $291,000 for Sierra-G. (*Id.*) Staff acknowledges that a utility must maintain its financial integrity, but having ratepayers pay more money now to prevent such a downgrade while increasing the cost of debt is illogical. (*Id.* at 20.)

84. Staff recommends that the Commission accept Staff's capital structure of 47.60-percent total debt and 52.40-percent total equity. (*Id.*)

85. Staff does not take issue with Sierra's cost of debt for Sierra as a whole or the electric and gas divisions, but it has two concerns about using a consolidated cost of debt for both divisions (*Id.* at 21.) Staff argues that Sierra has not provided adequate support for deviating from prior practices in previous general rate cases, and an incorrect application of the cost of debt may result in cross-subsidization between the gas and electric divisions. (*Id.* at 21-22). Staff additionally argues that Sierra is not required to file general rate cases for both electric and gas at the same time, and that it has full control over the timing of general rate cases for the electric and gas divisions, and Staff therefore recommends that each division's cost of debt be used to determine each division's ROR. (*Id.* at 22.)

86. Staff agrees that Sierra's certified cost of customer deposits is 5.24 percent, while recommending that the Commission approve a division-specific cost of debt for the gas and electric divisions as opposed to a consolidated cost of debt. (*Id.* at 23.)

87. Staff states that it has two issues with Sierra's proxy group and its screening criteria. (*Id.* at 17.) First, Staff states that Sierra has employed screening criteria not previously used, namely the criteria of company-owned generation contributing to at least 40 percent of sales and 60 percent of regulated operating income coming from regulated electric operations. (*Id.* at 18.) Staff states that Sierra's selected thresholds for its criteria are unclear, resulting in the exclusion of certain companies from the proxy group. (*Id.*)

88. Staff has three issues with Sierra's proxy groups – screening criteria that exclude certain companies solely on those criteria, certain screening criteria for electric utilities that are

more restrictive than Nevada Power Company's last general rate case with no explanation, and certain screening criteria for natural gas are restrictive. (*Id.* at 25-26.)

89. Staff elaborates that ten electric utilities are excluded from Sierra's proxy group based on the use of the company-owned generation criterion and the regulated electric operating income criterion, and some (if not all) of these companies have been used in Sierra's previous rate cases. (*Id.* at 27.) Staff explains that another natural gas utility is erroneously excluded from the proxy group based on just one criterion, and a further six combination (gas and electric) utilities are excluded from Sierra's proxy group based on the same two criteria mentioned above. (*Id* at 28.)

90. Staff provides its own proxy group as an alternative to Sierra's proxy group because Staff believes that Sierra's proxy group has too many screening criteria that were applied incorrectly and resulted in the inappropriate limitation of the size of Sierra's proxy group. (*Id.* at 29.) Staff states that it believes that removing some of Sierra's criteria balances the objectives of obtaining a sufficient sample size and a group that is comparable to the subject company, Sierra. (*Id.*)

91. Staff's constant-growth DCF results in an average ROE of 10.04 percent for combination utilities, 10.10 percent for electric utilities, 10.31 percent for gas utilities, and 10.14 percent for electric and gas utilities, with a range of 9.53 percent to 10.12 percent. (*Id.*) Staff's constant-growth DCF results are summarized in the table below:

Constant Growth DCF Results				
Price	**Combo**	**Electric**	**Gas**	**E+G**
60-day Average Price	10.07%	10.07%	10.33%	10.12%
90-day Average Price	10.02%	10.12%	10.29%	10.15%
Average ROE	**10.04%**	**10.10%**	**10.31%**	**10.14%**

(*Id.* at 32.)

92. Staff provides results from a three-stage DCF, which Staff argues is theoretically superior to the constant-growth model, as investors' expectations regarding the short-run growth rate versus the long-run growth rate are likely to differ. (*Id.*) Staff's three-stage DCF results are summarized in the table below:

Three-Stage DCF Results				
	Combination	**Electric**	**Gas**	**E+G**
G3 = 4.30%	8.87%	9.11%	9.04%	9.10%
G3 = 5.43%	9.63%	9.79%	9.90%	9.81%
Average	9.25%	9.45%	9.47%	9.45%

(*Id.* at 35.)

93. Staff's CAPM model results in an average ROE of 10.76 percent for the Combination utility proxy group, 10.77 percent for the electric utility proxy group, 10.42 percent for the natural gas utility proxy group, and 10.70 percent for the electric and gas proxy group. (*Id.* at 39.) Staff's ECAPM model results in an average ROE of 10.94 percent for the Combination utility proxy group, 10.93 percent for the electric utility proxy group, 10.64 percent for the natural gas utility proxy group, and 10.88 percent for the electric and gas proxy group. (*Id.*) Staff's CAPM and ECAPM results are summarized in the table below:

CAPM and ECAPM Results				
	Combination	Electric	**Gas**	**E+G**
CAPM				
4.40% Risk Free Rate	11.07%	10.99%	10.67%	10.98%
3.90% Risk Free Rate	10.56%	10.55%	10.17%	10.55%
Average	10.81%	10.77%	10.42%	10.76%

(*Id.*)

94. Staff states that it also conducted an allowed ROE/bond-yield analysis via a regression model. (*Id.* at 40.) Staff provides that based on its analysis, given the relevant 20-year Treasury bond yield for Q3 2023 of 4.40 percent (the average from Q2 2023 to Q1 2024), the projected average allowed ROE for electric utilities is 10.421 percent. (*Id.* at 46-47.) Applying the Sierra-specific adjustments of a 21-basis-point reduction, Staff's allowed ROE/bond-yield analysis shows that an ROE of 10.21 percent or lower is appropriate for Sierra-E. (*Id.* at 47.) Applying the Sierra-specific adjustments of an 11-basis-point reduction, Staff's allowed ROE/bond-yield analysis shows that an ROE of 10.10 percent is appropriate for Sierra-G. (*Id.* at 44.)

95. Staff argues that Sierra's analysis of regulatory risk is flawed and misinterpreted. (*Id.* at 60.) Staff asserts that the evidence provided in Sierra's testimony does not support Sierra's argument that the regulatory risk for Sierra is higher than the proxy group; rather, Sierra's testimony shows that regulatory risk appears to be in line with the proxy group. (*Id.*)

96. In particular, Staff notes that the risk factors identified by credit agencies, S&P and Moody's, regarding Sierra's capital expenditures and regulatory environment do not support the conclusion that Sierra faces more regulatory risk than the proxy group. (*Id.* at 67-68.)

Sierra's Rebuttal

97. Sierra does not agree that bond indentures differentiate between gas and electric assets, and that it does not require Sierra to pay bondholders from revenues generated exclusively from gas or electric. (Ex. 142 at 2.) Sierra argues that all revenues, whether from gas or electric customers, can be used to service tax-exempt debt. (*Id.*)

98. Sierra disagrees with Staff's assertion that Sierra should assign a different cost of debt to gas and electric customers. (*Id.* at 3.) Sierra states that because it does not run its gas

business liquidity any differently than it does the electric, the cost of debt should not be treated differently. (*Id.* at 4.) Sierra states that, due to the small size of Sierra-G, it is possible that gas customers benefit from being consolidated with a larger electric business in the event Sierra-G needs to issue debt on its own, as it could have trouble obtaining the debt at the same rate and bond amount as the larger Sierra-E. (*Id.*) Sierra argues that not having a consolidated cost of debt could indirectly result in Sierra-E customers subsidizing Sierra-G customers, the exact issue Staff hopes to avoid. (*Id.*)

99. Sierra states that it repurchased all tax-exempt debt as of September 2023, for the purpose of generating new cash proceeds that Sierra plans to use for general corporate purposes and not to fund a specific gas or electric project. (*Id.* at 5.)

100. Sierra states that, in the event that a rate case for gas and electric was not filed at the same time, a mismatch could be created as the rate-base allocation for each division would be set at different times (*Id.*) Sierra argues that consolidating the cost of debt between gas and electric temporarily corrects any mismatch between how the company allocates between taxable and tax-exempt debt. (*Id.* at 5-6.)

101. Sierra disagrees with Staff's proposed capital structure of 51.15 percent for Sierra-E and 52.45 percent for Sierra-G because it fails to acknowledge that Sierra's proposed capital structure is needed to support customer growth, legislative mandates, and system needs. (Ex. 146 at 5.) Sierra further argues that it has higher capital requirements (for projects such as Sierra Solar and Greenlink) at this time that it has not had in the past, and that the capital structure proposed by Staff will bring concerns for Sierra's investors. (*Id.* at 5-6.) Sierra expects that a higher equity level is needed for the next three to five years as the infrastructure projects are completed. (*Id.* at 6.)

102. Sierra disagrees with Staff's forecasted equity ratio because Sierra's proposed equity ratio is not a forecast but rather a reflection of the existing approval level only used for indicative direction. (*Id.* at 6.) Sierra characterizes its equity ratio and ROE in its Company Business Plan as conservative and states that the Commission should not rely on the amounts used in the business plan as any indication of what is needed. (*Id.*)

103. Sierra disagrees with Staff's definition of just and reasonable rates because it does not fit with Sierra's capital structure needed during the upcoming capital spend cycle. (*Id.* at 7.) Sierra argues that its December 2023 rate of return for Sierra-E was 5.71 percent, below the authorized rate of return of 6.95 percent granted by the Commission in Docket No. 22-06014. (*Id.*) Sierra argues that Staff is not taking into account the challenges that the company is currently facing, such as unprecedented customer growth, the building of new infrastructure, and the State's renewable energy goals. (*Id.*)

104. Sierra is also concerned about the methods used by Staff to arrive at its proposed equity ratio, in that Staff has departed from its traditional practice of basing its equity ratio recommendation on a previous five-year average. (*Id.* at 8.) Sierra argues that having a consistent methodology for determining capital structure is critically important because it guides Sierra's investment decisions. (*Id.*) Sierra argues that Staff's outcome-determinative approach and the use of an imputed capital structure in the current case is fundamentally flawed, as it provides no predictability for the company. (*Id.* at 9.)

105. Sierra agrees with Staff's assertion that Sierra is actively managing its equity ratio but disagrees with Staff's characterizations of the reasons why. (*Id.*) Sierra argues that it actively manages its equity ratio not only for financial stability, but also to support credit metrics and financial strength to meet its obligations to serve legislative goals (*Id.* at 9-10.)

106. Sierra argues that Staff's use of a hypothetical capital structure does not account for Sierra's need to meet investor demands and for sound regulatory policy to support positive credit metrics. (*Id.* at 10.) Sierra characterizes Staff's argument as asserting that investors are entitled to a lower return on an incremental portion of capital invested above its authorized equity level, which Sierra argues sends an improper signal to investors at a time when investor confidence is of great importance. (*Id.* at 10-11.)

107. Sierra states that a credit downgrade has already occurred and that it is not a hypothetical downgrade as argued by Staff. (*Id.* at 11.) Sierra is concerned about another potential downgrade coming, and it calls for the Commission and other parties to work together to ensure that does not happen. (*Id.*) Sierra argues that Staff is looking at the impact of the credit downgrade too narrowly, as it analyzes the impact of a downgrade for just one year. (*Id.* at 12.)

108. Sierra argues that Staff needs to take a holistic approach when analyzing the cost of a credit downgrade, as Staff's current recommendation will have a negative cost impact when compared with regulatory decisions that would be near-term credit supportive. (*Id.*) Sierra argues that a higher ROE over the next few years will be much cheaper than issuing debt after a credit downgrade. (*Id.*)

109. Sierra states that there are several ways for the Commission to create a supportive regulatory environment that would mitigate the impact of the credit downgrade. (*Id.* at 13.) Sierra states that aligning the equity ratio with its actual level of debt and equity is a primary way to address the issue, but the Commission could authorize an increased ROE as well. (*Id.*) Sierra states that the Commission could also include construction work in progress in the rate base, along with allowing for the timely recovery of prudent expenditures. (*Id.* at 13-14.) Sierra states

that the best approach, however, is for the Commission to consider all of these options holistically as a balance to the costs that Sierra must incur in the near-term. (*Id.* at 14.)

110. Sierra argues that Moody's issued Sierra's credit downgrade due to a lack of a supportive regulatory environment and the fact that its Sierra Solar project was authorized without any additional regulatory support of Sierra's cash-flow during construction. (*Id.* at 14-15.) Sierra states that a reasonable level of equity to support capital spend is necessary to avoid further downgrade and recommends using the actual capital structure (as opposed to a hypothetical one) as a component of regulatory support. (*Id.* at 15.)

111. Sierra disagrees with Staff's recommendation of a 9.5-percent ROE for Sierra-E and 9.4 percent for Sierra-G, because Staff understates the risk(s) Sierra faces due to wildfires, aging infrastructure that has depreciated, and the increase in Sierra's capital expenditures that increase regulatory lag, which places pressures on credit metrics. (*Id.* at 16-17.) Sierra further states that while it does control the timing of filing a general rate case, the time between general rate case filings is not the only factor in regulatory lag, but also the amount Sierra spends and does not recover before investments are put into rates, which means that more frequent rate cases do not ensure a reduction in regulatory lag. (*Id.*)

112. Sierra argues that its own management decisions have no impact on its interpretation of its financial risks as they relate to the Greenlink and Sierra Solar projects. (*Id.* at 18.) Sierra states that the decisions to move forward with these projects were driven by operational needs and the broader context of the challenges faced by Sierra in current market conditions. (*Id.* at 18-19.) Sierra reiterates that it does face increased risk at this time, contrary to Staff's position that it does not. (*Id.* at 19.)

113. Sierra states that Staff is downplaying the risk of BHE deploying its equity away from Sierra, because BHE is always going to invest its capital in companies that will give the best return, and Sierra constantly has to compete with its affiliates to obtain investment capital from BHE. (*Id.* at 21-22.)

114. Sierra states that it only brings projects forward for Commission approval based on what it believes is needed to meet an increasing load and legislative goals, and that it does not bring projects forward based on the impact of rate of return or ROE. (*Id.* at 23.)

115. Sierra disagrees with BCP's recommended 9.5-percent ROE (or Sierra-E and a 9.35-percent ROE for Sierra-G with a 55.19-percent equity ratio because the 2023 average authorized return for electric utilities cited by BCP (9.59 percent) is nine basis points higher than BCP's own recommendation of 9.5 percent and an even higher 9.64-percent for gas utilities. (*Id.* at 24.) Sierra also disagrees with BCP's recommendation that a further reduction of the ROE should be enacted if higher BSC are approved because the company's rate design proposal inherently recovers requested revenue requirement regardless of how the individual components are constructed. (*Id.*)

116. Sierra disagrees with SCP's recommendation of a 9.25-percent ROE with a 50-percent equity ratio for electric (reduced to 8.85 percent if the 55.19 equity ratio is approved) because SCP's analysis is not utility-specific. (*Id.* at 25.) Sierra states that SCP's analysis ignores the wildfire risks specific to Sierra that are not faced by other utilities, and is overly reliant on Charles Schwab's view of expected future returns for all U.S. large and small company stocks over the next ten years. (*Id.*) Sierra also argues that SCP's analysis ignores the fact that Sierra has not actually earned its authorized rate of return in the last few years, and that Sierra

has undertaken greater capital expenditures to provide reliable service and meet legislative mandates. (*Id.* at 26.)

117. Sierra states that SCP is downplaying the impact of Sierra's credit downgrade, and even though Nevada's regulatory environment is generally supportive, the credit ratings agencies are looking for additional regulatory support for Sierra's near-term operational needs. (*Id.* at 27.) Sierra argues that risky decisions now are required for long-term financial stability, and for the better of the both the customers and the utility for the future. (*Id.* at 28.)

118. Sierra argues that BCP is misinterpreting the S&P report and fails to point out that lack of regulatory diversity makes Sierra dependent on the Commission to sustain its credit grade. (*Id.*)

119. Sierra argues that Staff, BCP, SCP, and Walmart do not acknowledge that Moody's rating for Sierra's unsecured credit of Baa2 is an unusually low rank for a U.S. electric and gas utility, which indicates financial weakness relative to other peer utilities. (Ex. 143 at 5.) Sierra notes that the S&P stand-alone credit profile for Sierra is also low, two notches below the median stand-alone credit profile for 102 other companies. (*Id.* at 12.)

120. Sierra disagrees with Staff, BCP, and SCP's assertion that a stable outlook from a credit agency will not subsequently change, and further disagrees that the decisions made in this general rate case will not impact Sierra's credit rating in the future. (*Id.* at 13-14.) Sierra states that credit rating agencies (such as Moody's) will review the order issued in this case, and could issue a further downgrade if Sierra's cash flow to debt ratio falls to 14 or below on a sustained basis, due to significant delays or cost increases, insufficient support from BHE, or unfavorable regulatory recovery treatment. (*Id.* at 14-15.)

121. Sierra states that Staff's analysis of how a regulatory order affects credit metrics and ratings is faulty, because it addresses the wrong mechanism for supporting financial metrics and sustaining Sierra's credit ratings. (*Id.* at 17.) Sierra argues that Staff was incorrect to calculate a formula regarding an additional ROE and rate of return to support credit rating, and a much better metric would be to alter the capital structure. (*Id.*) Sierra also notes that Staff's analysis fails to include the long-term impact of debt instruments that will persist over decades that can be avoided via increasing the equity ratio for a few years. (*Id.* at 18.)

122. Sierra argues that while it benefits from the financial support it receives from BHE, the Commission should not rely solely upon financial support from BHE in lieu of safeguarding the financial strength of Sierra through stronger cash flow, as support from a holding company to a subsidiary may vary over time. (*Id.* at 6.) Sierra states that BHE has no obligation to provide financial support to any of its portfolio companies nor to continue ownership, so individual financial integrity is key to utilities being able to fulfill their ongoing obligations. (*Id.* at 19.) Sierra additionally argues that S&P downgraded Sierra's credit rating due to S&P's belief that BHE will be less willing to support its subsidiaries going forward, due to BHE's maintenance of its own credit ratings. (*Id.* at 20.)

123. Sierra argues that its risks are not lower than the average utility's, and one reason for that is because of its reliance on purchased power. (*Id.* at 22.) Sierra states that power purchases do not produce additional cash flow for the company, and there is the risk of price spikes (for gas operations) and delayed energy cost recovery with no operating cash flow to offset those risks. (*Id.*) Sierra also notes that no other intervenor witness addressed Sierra's wildfire risk, which could be catastrophic with a big enough wildfire, and that risk weighs heavily with investors and credit rating agencies. (*Id.* at 23-24.)

124. Sierra states that the most important relationship between capital structure and cash flow credit ratio is Cash From Operations before Working Capital ("CFO Pre-WC") divided by debt, which measures debt leverage (*Id.* at 24.) Sierra states that there is no other means in this docket for the Commission to use to enhance cash flow credit metrics, other than adjusting the capital structure and return on equity. (*Id.* at 27.)

125. Sierra argues that a higher ROE is needed for Sierra as compared to BHE because BHE is a much larger entity than Sierra, BHE has no obligation to provide a service to its customers, and because a reduction in equity and increase in its leverage would reduce Sierra's cash flow ratio of CFO Pre-WC/Debt. (*Id.* at 28-29.)

126. Sierra argues that Staff, BCP, and SCP place no importance on Sierra's individual credit strength, and that those parties overly rely on Sierra receiving support from BHE in making their arguments. (*Id.* at 33-34.) Sierra further argues that regulatory support for Sierra's credit is essential, due to Moody's and S&P's concerns about Sierra's weak cash flow metrics. (*Id.* at 34.) Sierra states that regulatory support for Sierra's individual financial status will avoid further adverse rating actions and build a foundation for a future upgrade. (*Id.* at 35.)

127. Sierra argues that, considering the recent downgrades, its risk profile is above average as compared to the proxy group, which is contrary to the conclusions drawn by Staff, BCP, SCP, and Walmart. (Ex. 145 at 6.) Sierra states that updated results continue to support its request for an ROE of 10.40 percent. (*Id.*)

128. Sierra states that changes in its long-term bond yields since the 2022 general rate case demonstrate an increase in the cost of capital, and that the recommendations of Staff, BCP, SCP, and Walmart do not reflect the current investor-required returns, nor do they reflect the current market conditions that require a higher cost of equity. (*Id.*)

129. Sierra argues that Staff's own analyses require a higher cost of equity that invalidates Staff's own recommendations – Staff recommends a 9.50 percent ROE for Sierra-E and a 9.40 percent ROE for Sierra-G, but Staff's own averages of the results of the three cost of equity estimation methodologies ranges from 10.20 percent to 10.28 percent, and even when CAPM and ECAPM are excluded, the results of Staff's models range from 9.93 percent to 10.03 percent. (*Id.* at 7.) Sierra states that Staff's estimation methodologies do overlap substantially with Sierra's, Staff establishes range excludes all cost of equity model results except for the DCF analysis. (*Id.* at 7.) Sierra states that Staff's inconsistency in the averaging of these analyses results in a midpoint of the ranges 90 basis points higher than Staff's recommended ROEs for Sierra. (*Id.*)

130. Sierra states that Staff's DCF models are inconsistent with the growth rates Staff rely upon, which results in the DCF model being understated. (*Id.*) Sierra also states that Staff incorrectly relies on the historical average dividends instead of annualizing the current dividend, which further skews DCF model results. (*Id.*) Sierra states that, similarly, Staff's CAPM and ECAPM models are internally inconsistent because they use a different risk-free rate in calculation of the market risk premium than is used as the risk-free assumption in the calculation of the methodology. (*Id.* at 8.) Sierra further states that Staff's risk adjustment to its Allowed ROE/Bond Yield Risk Premium analysis is flawed because it defies the relationship between risk and return that is fundamental to the discipline of finance, in that Staff calls for a lower ROE despite Sierra's credit downgrades that raise the risk to debt and equity holders. (*Id.*)

131. Sierra states that Staff's analysis of Sierra's business risks is flawed because it downplays Sierra's wildfire risk, and further only discusses wildfires as the only risk Sierra is

facing. (*Id.*) Sierra states that, additionally, Staff provides no comparison of the regulatory mechanisms relative to the proxy group. (*Id.*)

132. Sierra states that Staff's own analyses of ROE result in a range of 10.21 percent to 10.71 percent, which is consistent with Sierra's recommendation of 10.40 percent ROE. (*Id.*) Sierra states that while it disagrees with BCP and SCP's recommended ROE, reasonable adjustments to those analyses demonstrate that their recommendations understate the cost of equity. (*Id.*) Sierra states that the midpoint of BCP's cost of equity is over 10.2 percent for the gas utility proxy group, and over 10.60 percent for the electric utility proxy group, and that BCP's analysis understates the cost of equity by 10 to 25 basis points. (*Id.* at 9.)

133. Sierra states that its proposed equity ratio is reasonable because it is well within the range of actual equity ratios of the utility subsidiaries of the proxy group companies. (*Id.*) Sierra disagrees with the approach used by Staff and SCP that compares Sierra's proposed equity ratio to the average ratios of the proxy group at the holding company level, but also believes that had Staff and SCP performed their analysis correctly, it would still result in an equity ratio that is slightly lower than the proxy group average equity ratios. (*Id.*)

134. Sierra states that the proxy groups used by Sierra and Staff differ because Staff does not rely on a generation screen or a screen that limits the proxy group by the amount of its operations that are derived from regulated operations. (*Id.* at 30.) Staff states that the elimination of these screens establishes electric and combination gas/electric utility groups that are less comparable to Sierra than Sierra's own proxy group, specifically, Staff's inclusion of transmission and distribution utilities that do not have the risk of generation and companies that derive less of their operating income from regulated electric operations. (*Id.*)

Commission Discussion and Findings

<u>Return on Equity</u>

135. In determining an appropriate ROE, the Commission relies upon frameworks contained in Nevada law and the two seminal United States Supreme Court decisions regarding ratemaking: *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1942) and *Bluefield Water Works and Improvement Company v. Public Service Company Commission of West Virginia,* 262 U.S. 679 (1923). Pursuant to *Hope* and *Bluefield*, regulators must consider numerous factors when setting a utility's return. (*Hope* 320 U.S. at 605; *Bluefield* 262 U.S. at 692.) As the *Hope* Court stated, regulators can and should consider "appropriate protection to the relevant public interests, both existing and foreseeable," and "it is the result reached not the method employed which is controlling." (*Hope*, 320 U.S. at 605.) Nevada utilities are entitled to the opportunity to earn an authorized and reasonable return on their investment that is "adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties." (*Nevada Power Co. v. Pub. Serv. Comm'n,* 91 Nev. 816, 825, 544 P.2d 428, 434-35 (1975)). In establishing a zone of reasonableness and determining an ROE within that range, the Commission relies upon expert testimony and evidence that apply the principles of finance, accounting, and economics to the cost of a particular utility's common equity. This evidence includes the results of each expert's ROE studies and the expert's judgment in assessing macroeconomic conditions, capital markets, and Sierra's particular circumstances (e.g., capital structure, risk profile, and regulatory environment.)

136. The Commission finds, based upon the evidence in the record, that the range of reasonableness for Sierra's ROE falls between 9.20 percent and 9.90 percent for Sierra-E, and between 9.10 percent and 9.90 percent for Sierra-G and approves ROEs of 9.65 and 9.50 percent

for Sierra-E and Sierra-G, respectively, which are within the reasonable ranges. In conjunction with its approval of an ROE of 9.65 percent for Sierra-E and 9.50 percent for Sierra-G, the Commission approves a capital structure in which the ratio of total debt to total capital is 47.60 percent and total equity to total capital is 52.40 percent, with a total cost of debt of 4.89 percent for both Sierra-E and Sierra-G. The resulting overall costs of capital are 7.38 percent for Sierra-E and 7.31 percent for Sierra-G.

137. The Commission approves Staff's recommended ROE range of reasonableness, which is based on Staff's use of the following: two DCF models (Constant Growth and Three-Stage); CAPM and ECAPM; and an Allowed ROE/Bond Yield model. Staff's Constant Growth DCF analysis results are summarized in the following chart and estimates an average ROE of 10.04 percent for combination utilities using average stock prices for 60-day and 90-day periods ending February 29, 2024:

Staff's Constant Growth DCF Results

Price	Combination	Electric	Gas	E+G
60-day Average Price	10.07%	10.07%	10.33%	10.12%
90-day Average Price	10.02%	10.12%	10.29%	10.15%
Average	10.04%	10.10%	10.31%	10.14%

(Ex. 300 at 32.)

138. Staff produced two different three-stage DCF results using different third-stage growth rates;[3] however, it relied on the 5.43 percent third-stage growth rate based on the historical growth rate of the U.S. economy since 1929 and the expected inflation rate, and a 4.30 percent third-stage growth rate based on macroeconomic indicators published by the U.S. Energy Information Administration ("EIA") consistent with analyses from previous dockets. Staff's

[3] Sierra did not conduct a three-stage DCF analysis.

three-stage DCF analysis results in an ROE of 9.25 percent for combination utilities as summarized in the following chart:

Staff's Three-Stage DCF Results

	Combination	Electric	Gas	E+G
3rd Stage G = 4.30%	8.87%	9.11%	9.04%	9.10%
3rd Stage G = 5.43%	9.63%	9.79%	9.90%	9.81%
Average	9.25%	9.45%	9.47%	9.45%

(*Id.* at 35.)

139. The Commission accepts Staff's conclusion that the results from both of its DCF analyses indicate an average ROE for Combination utilities of 9.65 percent within a range of 9.25 percent to 10.31 percent for Combination, electric, gas, and electric/gas utilities and notes its use of the higher third-stage growth rate of 5.43 percent results in a higher average DCF ROE estimate and range than using the lower 4.30-percent third-stage growth rate, or averaging or otherwise blending the results produced from both of the third-stage growth rates.

140. Staff used two different risk-free rates in its CAPM and ECAPM analyses to account for the rising 20-year treasury bond yields: (1) the 4.40 percent risk-free rate that is the average 20-year Treasury bond yield between December 1, 2023, and February 29, 2024; (2) the 3.90 percent risk-free rate that is projected based on Blue Chip Financial Forecasts Q3 2025 consensus projected 30-year treasury bond yield of 4.00 percent. Staff used a MRP of 7.17 percent in its CAPM analysis based on the historical MRP since 1926. Staff's CAPM and ECAPM analysis returns an average ROE of 10.81 percent for Combination utilities with a range of 10.17 to 11.07 percent, as summarized in the following chart:

CAPM and ECAPM Results

	Combo	Electric	Gas	E+G
4.40% Risk Free Rate	11.07%	10.99%	10.67%	10.98%
3.90% Risk Free Rate	10.56%	10.55%	10.17%	10.55%
Mean	10.81%	10.77%	10.42%	10.76%

(*Id.* at 39.)

Staff notes the CAPM and ECAPM estimates should be viewed with some caution due to the model's sensitivity to changes in Treasury yields, which the Commission acknowledges here as it has in past dockets.

141. Staff also performed an Allowed ROE/Bond Yield model, which analyzes the relationship between ROEs awarded by state regulators and the long-term U.S. Treasury bonds that prevailed when those ROEs were awarded. Staff's Allowed ROE/Bond Yield model, which performs a regression analysis on ROEs approved by regulators over the 20-year U.S. Treasury Bond Yields in recent quarters, projects an allowed ROE for electric and gas utilities of 10.21 percent and 10.10 percent, respectively. (*Id.* at 40, 44.)

142. The Commission finds the issues raised by Staff with regard to the proxy group used by Sierra are compelling. Staff raised concerns with Sierra's proxy group screening criteria excluding several companies based solely on that criteria, with Sierra applying similar screening criteria used in prior dockets but increasing the threshold level for inclusion to be more restrictive in the instant Docket, and with Sierra increasing the regulated operating income criteria percentage to 70 percent from 50 percent, departing from the methodology used in prior general rate case dockets.

143. As noted by Staff, Sierra's screening criteria excludes ten electric utilities from the proxy group that have been included as proxies in some, if not all, of Sierra's prior general rate cases. One natural gas utility is excluded from the proxy group based solely on the regulated natural gas operating income criteria. Six combination utilities are excluded based on the use of the same two criteria for electric utilities: company-owned generation and regulated electric operating income.

144. The Commission finds that Staff's proxy group, which includes all the companies included in Sierra's proxy group, along with the 17 companies noted by Staff that were excluded based on Sierra's restrictive screening criteria, is a larger, more representative, and reasonable proxy group.

145. The Commission agrees with Staff that when appropriate adjustments are made, Sierra's ROE analysis results decrease significantly lower than Sierra's requested 10.40 percent ROE for Sierra-E and Sierra-G, and within Staff's recommended ROE range of reasonableness of 9.20 percent to 9.90 percent for Sierra-E and between 9.10 and 9.90 percent for Sierra-G.

146. The Commission notes that since its approval of a 9.50-percent ROE in Sierra's last general rate case in 2022, capital market conditions with respect to inflation, interest rates, and energy costs have improved considerably. In the Federal Reserve's current interest rate increase cycle, it made its initial interest rate increase in March 2022, its last increase in July 2023, and is poised to begin lowering interest rates by the end of 2024. Inflation peaked mid-year in June 2022 at more than nine percent and was reported at three percent in June 2024.

147. Energy costs have fallen since Sierra's general rate case filing in Docket No. 22-06014. In Sierra's filing in Docket No. 22-06014, Sierra cited its deferred energy cost balance as a liquidity constraint and negative impact to cash flow and credit metrices. In the instant docket, Sierra acknowledges that its deferred energy mechanism and balances provided a $384-million liquidity and cashflow benefit for the year ended December 31, 2023. (Tr. at p. 114, lines 6-10.)

148. Additionally, Sierra's general rate case cycle has been shortened since the Commission's Order in Docket No. 22-06014. At the time of Sierra's general rate case filing in Docket No. 22-06014, where the Commission approved an ROE of 9.5 percent and equity ratio of 52.4 percent, Sierra was subject to a three-year general rate case cycle. Since that time,

legislation has been enacted that provides Sierra the ability to file general rate cases on an annual basis, which significantly reduces the time period for capital investments to be reflected in rates and converted to operating cash-flow and earnings. Sierra acknowledges that any negative credit-related or financial impacts of its capital expenditure plan and forecast are temporary. (Tr. at 188, lines 19-21, *see also* Tr. at 235, lines 21-24.) The Commission notes that these impacts have been made even more temporary than Sierra's historical experience due to the shortened rate-case cycle, which for example, enabled the instant general rate case filing to occur in the in February 2024 instead of June 2025 as would have been the case under the previous statutory filing requirements.

149. The Commission also agrees that Sierra has alternatives to large rate-based projects. If Sierra does not have the balance sheet or credit capacity to undertake large rate-based capital projects without creating risk to its credit quality, cost of capital, and cost to customers, it can propose and structure such projects outside of rate base. Sierra has a history of adding renewable energy resources and large transmission projects similar to Greenlink outside of rate base. Renewable energy supply resources can be contracted for using PPAs with third-party developers. Sierra is a counterparty to numerous existing PPAs and has proposed PPAs for the acquisition of new renewable energy supply resources in its current joint Integrated Resource Plan ("IRP") filing in Docket No. 24-05041. Sierra's One Nevada Line transmission project ("On-Line"), which Sierra jointly operates with Nevada Power, was developed and placed in service through an operating lease structure with a third-party developer. Sierra can consider similar structures or joint venture partners for its Greenlink project if it does not have the capacity to absorb the size, scale, or increasing costs of the Greenlink projects as proposed without significant increases to rates charged to customers from elevated ROE and Equity ratios.

150. The Commission agrees that the evidence in the record indicates Sierra's proposed ROE (and equity ratio) are not supported by contemporary state regulator decisions. State regulators granted an average ROE of 9.6 percent and 9.64 percent, respectively, for electric and gas utilities during 2023. (Ex. 300 at 6.) In Q1 2024, state regulators granted an average ROE of 9.66 percent and 9.78 percent, respectively, for electric and gas utilities. (*Id.*)

151. In addition, the average authorized equity ratios reported by S&P Global in 2023 and 2022 were 51.15 percent and 50.36 percent, respectively, for electric utilities and 52.45 percent and 51.38 percent, respectively, for gas utilities. (*Id.* at 15.) For Q1 2024, S&P Global reported an average authorized equity ratio of 48.25 percent for electric utilities and 53.86 percent for gas utilities. (*Id.*)

152. Sierra's proposed ROE of 10.4 percent and equity ratio of 55.19 percent are substantially higher than those granted to electric and gas utilities by State regulators from 2022 through the first quarter of 2024. The Commission does not find Sierra's recommended ROE, proposed equity ratio, and resulting weighted average cost of capital reasonable in light of state regulator ROE and equity ratio decisions in 2022 through the first quarter of 2024.

153. For the reasons stated above, and consistent with the substantial evidence provided in these dockets, the Commission finds that ROEs of 9.65 percent for Sierra-E and 9.50 percent for Sierra-G balance the interests of ratepayers and shareholders appropriately and results in just and reasonable rates. The Commission finds that these ROEs are commensurate with returns on investments in other enterprises having similar corresponding risks, and they are sufficient to assure confidence in the financial integrity of the utility and for Sierra to attract capital.

Cost of Debt

154. The Commission accepts Sierra's consolidated cost of debt at Certification of 4.89 percent and finds it appropriate. The Commission accepts Sierra's proposed allocation of tax-exempt bonds and resultant cost of debt of 4.89 percent for both the Sierra-E and Sierra-G divisions. The Commission agrees with Sierra that the tax-exempt debt does not contain requirements or restrictions limiting it to the historical allocation of these bonds to gas customers. Accordingly, the Commission accepts Sierra's proposed allocation of these bonds in the same manner as its taxable first mortgage bonds and the resultant cost of debt of 4.89 percent for both the Sierra-E and Sierra-G divisions.

Capital Structure

155. The Commission approves Staff's recommended capital structure, as noted in the above discussion, and finds that a capital structure for both Sierra-E and Sierra-G in which the ratio of total debt to total capital is 47.60 percent and total equity to total capital is 52.40 percent results in just and reasonable rates.

V. REVENUE REQUIREMENT

A. Tracy Area Master Plan ("TAMP")

Sierra's Position

156. Sierra is requesting recovery of costs associated with four projects in the Tracy Area, where the Reno Technology Park ("RTP") and Tahoe Reno Industrial Center ("TRIC") are located, along with other large industrial customers. (Ex. 189 at 19.) Sierra states that the projects included for recovery in this general rate case are the West Tracy 345/120 kV Substation, the Apple 120 kV Expansion, the Redwood Expansion, and the Tracy 120 kV Reconfiguration. (*Id.* at 20.) Sierra states that all of these projects are necessary to meet load demands in the Tracy Area, and that each project was installed and placed in service by May 13,

2022. (*Id.* at 26.) Sierra states the overall costs of the four projects is $20,671,874, including Allowance for Funds Used During Construction ("AFUDC"). (Ex. 192 at Wagner CERT-1.)

BCP's Position

157. BCP provides that Sierra is seeking approval for recovery of funds from the West Tracy 345/120 kV substation, Apple 120 kV Expansion, Redwood Expansion, and Tracy 120kV reconfiguration as part of the TAMP, along with some other previously Commission-approved projects. (Ex. 406 at 12-13.) BCP notes that the Commission approved these projects based on Sierra's representations that the load which these new facilities had been built for was on track. (*Id.* at 13.)

158. BCP states that the Tracy Area equipment was represented by Sierra as being able to handle 360MW as of 2023, but the Tracy Area load is currently only 192MW. (*Id.* at 13-14.)

159. BCP states that Sierra has used the Master Plan approach when it comes to cost responsibility for projects in the Tracy Area, which looks at the applicant's projects and identifies what will be classified as transmission facilities up front. (*Id.* at 14.) Under this approach, ratepayers can be harmed because they end up paying for facilities for which load may take time to materialize, creating a possible intergenerational subsidy between current and future ratepayers. (*Id.* at 16-17.)

160. BCP states that Sierra will argue that these TAMP projects are used and useful and therefore eligible for recovery, but BCP argues in response that the problem of investing to secure higher load capacity and then loads, billing determinants, and revenue not fully materializing remains. (*Id.* at 17.)

161. BCP recommends moving 42 percent of the TAMP projects from plant in use to plant held for future use ("PHFU"), and if the loads materialize as promised by Sierra, Sierra can

create a regulatory liability. (*Id.* at 17-18.) BCP argues that future billing determinants and their respective revenue can accumulate until the next general rate case for the benefits of ratepayers, as they are currently paying for unused capacity and not receiving the benefit of a revenue offset between general rate cases. (*Id.* at 18.)

162. BCP also recommends that Sierra's rate base request for the Tracy 120 kV reconfiguration be disallowed as the project was not completed during the certification period. (Ex. 402 at 12.)

Staff's Position

163. Staff provides that the TAMP was developed to help serve large loads Sierra had forecasted in the TRIC. (Ex. 314 at 3). Staff then argues that 45 percent of the TAMP costs be placed into PHFU because the load that these facilities were built to support has not shown up and the facilities are not being used for the purposes of which they were built. (*Id.* at 3-4.)

164. Staff states that it arrives at the 45 percent deferral based on the current observed load from 2018-2023 in the TAMP versus the load Sierra told the Commission would occur by 2023 in a previous docket. (*Id.* at 5.) Staff states that its calculations showed that load is still lacking by 45 percent. (*Id.*)

165. Staff is concerned that if the Commission allows recovery of these TAMP projects, all rate payer and all rate classes will be paying for the facilities until the load shows up and Sierra files another general rate case to reset the rate and includes new billing determinants. (*Id.* at 6.) Staff argues that this would temporarily allow Sierra to collect the new rate from the current rate payers and the revenue from any new load that appears between now and the filing of the next general rate case. (*Id.* at 6-7.)

166. Staff states that if the Commission is disinclined to place TAMP costs into PHFU, Staff would then recommend in the alternative placing all billing determinants and revenue associated with any TAMP/TRIC load that accrues into a regulatory liability account, which would alleviate burdening existing customer with underutilized facilities and provide a mitigation mechanism for current rate payers to receive when Sierra files its next general rate case. (*Id.* at 7-8.)

167. Staff recommends that the Commission reclassify approximately $37.881 million for the TAMP project from this general rate case and reclassify the costs to PHFU. (Ex. 320 at 5.)

Sierra's Rebuttal

168. Sierra disagrees with Staff's recommendation to defer 42 or 45 percent of the total TAMP costs into PFHU. (Ex. 247 at 2.) Sierra contends that the load for these projects has indeed shown up, and that the project phases are fully operational and serving load. (*Id.* at 2.) Sierra states that once an asset is used and useful, it is required that the entire asset be placed into electric plant in service. (*Id.*) Sierra states that the TAMP projects cannot be placed into PFHU as all the TAMP facilities are being currently used and are servicing customer load. (*Id.* at 3.) Sierra states that it is merely going along with definitions from the Federal Energy Regulatory Commission ("FERC") for "used and useful" and FERC designations for a network upgrade. (*Id.* at 3-4.)

169. Sierra states that the loads are continuing to grow, and that large TRIC customers will be paying for the facilities that have been built. (*Id.* at 6.) Sierra asserts that the loads have occurred, the large customers are paying now and will pay in the future for the projects that have been completed. (*Id.*)

170. Sierra states that per Sierra Rule 9, it is required to build for and serve the full loads provided by customers, and that building for initial load only is a violation of Rule 9 that also could result in imprudent rate design practice, ultimately costing customers more. (*Id.* at 6-7.)

171. Sierra disagrees with Staff's assertion that four new projects are being requested for recovery as part of this filing, because it has already introduced three of the four projects in previous dockets. (*Id.* at 7-8.) Sierra states that the only new project being presented is the Redwood Expansion. (*Id.* at 8.)

172. Sierra notes that the Commission rejected a similar Staff request (to place 50 percent of TAMP costs into PHFU) in Docket No. 22-06014, when the Commission found that load had shown up for all TAMP projects, the projects are used and useful, and that large customers in the area are fully bundled, paying, and will pay for these projects. (*Id.* at 10-11.)

173. Sierra states that Staff and BCP have not provided any evidence that TAMP/TRIC costs are imprudent, nor do Staff and BCP recommend disallowing any portion of recovery, but rather merely delaying it. (*Id.* at 11.) Sierra states that recovery should not be delayed, absent a showing that the TAMP/TRIC projects are not used and useful. (*Id.*)

174. Sierra disagrees with Staff's assertion that recovery of costs associated with the Tracy 120 kV reconfiguration should be disallowed, as while the project is not fully complete, it is being completed in distinct phases. (Ex. 245 at 13.) Sierra states that this current filing seeks recovery only for the portion of the project that was completed, energized, and placed into service within the certification period. (*Id.* at 13.) Sierra states that the six underrated breaker replacements alluded to in BCP's testimony are not being included for recovery in the current

general rate case. (*Id.*) Sierra states that it is only seeking recovery for costs incurred to change the line terminations and bus improvements. (*Id.* at 14.)

Commission Discussion and Findings

175. The Commission finds that costs associated with the TAMP being sought for recovery are for facilities that are in service and used and useful. However, the Commission also recognizes that those facilities are currently underutilized as additional load from new customers has yet to materialize. Despite Sierra's assertions that customers representing 100 percent of the TAMP's designed load would arrive, that has yet to happen. The Commission recognizes that the full build-out of a master-planned development like the TAMP can occur within an uncertain timeframe and that such uncertainty presents risk. In this instance, the Commission is faced with balancing the risks to Sierra and its customers with encouraging reasonable infrastructure investments that support the energy needs of a growing Nevada.

176. To limit existing customers' responsibility for paying the costs of the TAMP-related facilities at issue, the Commission orders Sierra to establish a regulatory liability account, with carry, to capture BTGR and BSC revenues associated with new incremental customers and load within the TAMP area. If, prior to the filing of Sierra's next general rate case, the revenues recorded to the regulatory liability fully offset the total TAMP infrastructure investment included for recovery in the revenue requirement of this general rate case, Sierra may cease recording any additional incremental revenues to the regulatory liability at that time. The Commission finds that this arrangement is investment-supportive and mutually beneficial to Sierra and its customers (both existing and future). The Commission finds that including all of Sierra's TAMP infrastructure investment into the revenue requirement for recovery through rates in this general rate case will allow Sierra the opportunity to be made whole for its investment as it relates to the

rate-effective period of this general rate case. Additionally, recording incremental revenues from potential new TAMP customers and load in a regulatory liability will not adversely affect Sierra's opportunity to fully recover on its investment, but it will ensure that existing and future customers are appropriately credited for any incremental revenues that would otherwise accrue to Sierra as windfall profit.

177. Regarding the recommendations of Staff and BCP to record the underutilized portion of the TAMP energy facilities investment as PHFU, the Commission does not find that such an action is appropriate at this time. In the event that the TAMP energy facilities infrastructure remains underutilized and the probability or timeline of new load arriving remains uncertain, recording some portion of Sierra's investment in the underutilized infrastructure as PHFU is an action that the Commission may consider requiring in the future.

B. Critical Substation T

Sierra's Position

178. Sierra is requesting for recovery $6,444,493 for costs associated with the Critical Substation T perimeter wall. (Ex. 192 at Wagner CERT-1).

BCP's Position

179. BCP states that the masonry fence for Critical Substation T was completed during the certification period, but by Sierra not including the project in its certification filing, Sierra is giving the impression to the intervenors that this fence was not to be completed during the certification period. (Ex. 402 at 9.)

180. BCP recommends that the Commission disallow recovery for the masonry fence for Critical Substation T because it was incomplete as of April 16, 2024, which falls within the certification period but is not listed in Sierra's certification filing. (*Id.*)

Staff's Position

181. Staff recommends disallowing Sierra's cost recovery request for replacing an existing chain link fence at Critical Substation T with a concrete masonry unit block wall and reinforced gates. (Ex. 314 at 8.) Staff is recommending this cost be disallowed because the project was not completed by the end of the certification period, as the project was missing the main gate entrance. (*Id.* at 9.) Staff disagrees with Sierra's assertion that a 6-to-8-foot chain link fence does not support the idea that Sierra is protecting a critical substation, and Staff was told by Sierra on-site that the project was not finished yet. (*Id.*) Staff further recommends that recovery of this project be deferred to the next general rate case (*Id.*)

182. Staff also has concerns about Sierra's cost recovery request for this project, as it contained requests for additional funds due to "specialized instructions and excavation techniques to construct" that were never elaborated upon or explained by Sierra. (*Id.*) Staff has further concerns about Sierra's desires to build such a fence on top of an existing gas line that feeds the Sierra Tracy power plant, and that there are inconsistencies with Sierra's reasoning for building such a fence. (*Id.* at 11.)

183. Staff states that if the Commission decides not to order Sierra to include this project in the next general rate case instead of the current one, the Commission should remove 50 percent of the costs from the project, which Staff justifies by listing issues and inconsistencies with this project that would make full recovery of costs unjust and unreasonable. (*Id.* at 13.)

184. Staff recommends that the Commission disallow approximately $6.444 million of cost for the Critical Substation T perimeter wall project from the Sierra-G rate base. (Ex. 320 at 6.)

Sierra's Rebuttal

185. Sierra disagrees with Staff and BCP's assertion that recovery for the costs associated with the Critical Substation T Perimeter Wall because the project was substantially completed prior to the end of the certification period. (Ex. 245 at 3.) Sierra states it has completed 100 percent of 2,200-foot Concrete Masonry Unit wall, the 360-foot cut/climb resistant metal fence, and the 20-foot gate at the substation's 20-foot gate at an alternate access point, with only the 30-foot gate needing to be completed, which was purposefully delayed by Sierra. (*Id.* at 3.) Sierra provides that it installed a temporary chain link fence in the area where the gate was to be completed. (*Id.* at 4-5.)

186. Sierra disagrees with Staff's claim that security was reduced due to the fact that Critical Substation T was fully enveloped by various walls and fences, all completed during the certification period. (*Id.*) Sierra maintains that this fencing is needed for security, but that it is not including $485,000 associated with the 30-foot gate and drive apron in this general rate case. (*Id.* at 5.)

187. Sierra categorically denies producing any false documents in this case, and that any errors or omissions included in Sierra's filings were due to high turnover for Sierra's various project managers, and due to an evolving understanding of the project's constraints. (*Id.* at 10.) For this reason, and due to the fact that Sierra discovered a gas line during excavation for the fencing, Sierra disagrees with Staff's alternative recommendation to disallow half of the costs of recovery for this project. (*Id.* at 8.)

188. Sierra concludes that because this project was substantially complete and that the CMU wall and metal fence are actively providing perimeter protection, the project can be classified as used and useful and therefore able to be included for recovery. (*Id.* at 11.)

Commission Discussion and Findings

189. The Commission finds that Staff and BCP raise valid concerns regarding the timing of the project's completion and the manner in which Sierra presented the project for inclusion into the revenue requirement. However, neither party appears to dispute the need for the perimeter barrier and, at hearing, Sierra described how a block wall provided additional security. (Tr. at 494-495: 11-17.) The Commission agrees that that updated perimeter barrier is used and useful, and that the actions taken by Sierra to delay the completion of the gate and apron were prudent. The Commission finds that Sierra shall be permitted to recover approximately $6.444 million for Critical Substation T and that the $485,000 in costs for the gate and apron are appropriately not included in the revenue requirement at this time.

C. Goldfield Substation Rebuild

Sierra's Position

190. Sierra provides that this project involves a rebuild of the existing Goldfield Substation by replacing the transformer, reclosers, a regulator, and installing a new control enclosure. (Ex. 192 at 6.) Sierra states that the project is necessary due to slow but continuous load growth in the Goldfield area. (*Id.* at 6.) Sierra states that the facilities were installed and placed in service by March 13, 2023. (*Id.* at 7.) Sierra is seeking to include $978,319 in its revenue requirement for costs associated with this project. (*Id.*)

BCP's Position

191. BCP recommends that the rate base request for the Goldfield Substation Rebuild be disallowed because of the limited time for discovery. (Ex. 402 at 8.) BCP states that the Goldfield Substation Rebuild project was finished on March 13, 2023, which was well before Sierra's application in this general rate case. (*Id.*) BCP argues that because the information about the project was not made available to intervenors until May 13, 2024, it was not given

enough time for research and the preparation of testimony, and the recovery should therefore be disallowed. (*Id.*)

Staff's Position

192. Staff recommends rejecting the recovery of costs associated with the Goldfield Substation Rebuild project because it does not meet the certification rules for inclusion in this case. (Ex. 314 at 17-18). Staff states that the project was brought forward for the first time on May 13, 2024, which did not give Staff sufficient time to review and vet the project. (*Id.* at 18.) Staff argues that Sierra should have filed an amendment to its certification testimony in February or March of 2024, instead of waiting until May to first introduce the project. (*Id.*) Staff argues that Sierra should bring this project back for the next general rate case so the project can be properly presented and then vetted by Staff and other parties. (*Id.* at 19.)

193. Staff recommends that the Commission disallow the approximately $0.978-million cost of the Goldfield Substation Rebuild project from the Sierra-E rate base. (Ex. 320 at 8.)

Sierra's Rebuttal

194. Sierra disagrees with Staff and BCP's recommendation to disallow recovery of the temporary transformer portion of the Goldfield Substation Rebuild. (Ex. 245 at 11.) Sierra states that this request for recovery was unintentionally omitted from the original filing, and Sierra only discovered its mistake while preparing to file certification testimony. (*Id.* at 11-12.) Sierra further states that it made every effort to have the binder on the project available by May 13, 2024, and that the temporary transformer at the Goldfield Substation is but a small part of the overall rebuild happening there. (*Id.* at 12.) Sierra states that this temporary transformer is the only aspect of the rebuild being included in this application, and it was necessary to install to

meet load demands while the substation continues to be rebuilt. (*Id.*) Sierra argues that due to the smaller nature and limited impact of this project, a month is sufficient time for Staff and intervenors to review and vet the project. (*Id.*) Sierra states that because the temporary transformer is in place and energized, it should be considered used and useful, and therefore included for recovery in Sierra's revenue requirement. (*Id.* at 13.)

195. Sierra states that Staff's adjustment should be $0.970 million for the Goldfield Station Rebuild. (Ex. 240 at Hanshew-Rebuttal-6.) Sierra argues that Staff's calculation for recovery is incorrect in that it should include $0.013 million of Accumulated Deferred Income Taxes ("ADIT"). (Ex. 234 at 4.)

Commission Discussion and Findings

196. The Commission agrees with Staff and BCP that Sierra did not meet the certification requirements for including the Goldfield Substation rebuild in this case. The project was energized March 13, 2023, and omitted from the original application by Sierra. Sierra did not make the project available for review to the BCP and Staff until May 13, 2024. This was the first opportunity that BCP, Staff, and any intervenors had to vet the project. The Commission also agrees with Staff and BCP that the late addition of this project did not provide sufficient time for review in this case. The Commission therefore disallows recovery of costs associated with the Goldfield Substation rebuild as it was not included in Sierra's original filing and was not made available for review until the certification filing, even though the project was energized in March of 2023. In its next general rate case, Sierra may request that the costs of this project be included in Plant-In-Service, net of any accumulated depreciation.

D. Earnings Sharing Mechanism ("ESM")

BCP's Position

197. BCP states that Sierra currently has an ESM in place and recommends that the ESM continue to be used for Sierra-E while also extending the ESM to Sierra-G without restrictions. (Ex. 408 at 6; *see also* Ex. 406 at 19.)

198. BCP recommends continuing the existing earning sharing mechanism and extending it to Sierra-G for several reasons. (Ex. 408 at 6.) First, BCP states that the earnings sharing mechanism not only incentivizes cost-cutting measures by the utility, but it also protects ratepayers against excessive over-earnings by the utility that could result from these cost-cutting measures between rate cases. (*Id.*) BCP notes that because Sierra/NV Energy has a long and consistent history of over-earning, it is important to keep these ratepayer protections in place. (*Id.*) BCP maintains that the Commission should keep the earnings sharing mechanism safeguards in place at least until Sierra is no longer over-earning on a consistent and significant basis. (*Id.*)

199. BCP recommends extending the ESM to Sierra-G because without it, Sierra-G would be able to retain over-earnings indefinitely, as there is no other mechanism by which to correct the over-earnings. (*Id.* at 9.) BCP recommends that the ESM should accrue interest, exclude below-the-line items, be symmetrical, and be subject to audit in a general rate case. (*Id.* at 10.)

Staff's Position

200. Staff recommends that the Commission approve the earnings sharing regulatory liability as filed in the Certification period and the continuance of the earnings sharing mechanism utilizing the current methodology, incorporating the ROE as approved in this Docket. (Ex. 319 at 9.)

Sierra's Rebuttal

201. Sierra notes that it is not proposing any changes to the ESM for Sierra-E in this general rate case and expects that it will continue in its current format. (Ex. 252 at 18.)

202. Sierra states that while it would implement an ESM for Sierra-G if directed by the Commission to do so, it is not reasonable to try to calculate carry on ESM liability prior to the closing of year-end financial records. (*Id.* at 20-21.) Sierra goes on to state that its annual Deferred Energy Account Adjustment ("DEAA") filing is the best way to have the annual shared earnings calculated, because it allows any adjustments to be made in a timely manner and in the subsequent year from when the shared earnings are determined. (*Id.* at 21.)

203. Sierra states that an ESM is not necessary for Sierra-G given its size, but if the Commission were to implement one, Sierra expects the methodology and intent would mirror what is utilized for electric purposes. (*Id.* at 18.)

Commission Discussion and Findings

204. The Commission finds that the ESM is a valuable tool in balancing the interests of ratepayers and shareholders during the general rate case rate-effective period. The Commission agrees with Staff that the ESM shall be continued for Sierra-E under the current methodology incorporating the ROE as approved by this Order. As such, earnings calculated in accordance with the methodology presented in the annual DEAA shall be split 50 percent to ratepayers and 50 percent to shareholders for earnings in excess of 30 basis points over the approved ROE of 9.65 percent, or 9.95 percent. Sierra did not contest continuation of the ESM for Sierra-E.

205. The Commission rejects BCP's recommendation to accrue carrying charges on any ESM regulatory liability prior to the final adjustments that are made at year-end. These may significantly affect the amount of the liability and would result in carry being recognized earlier in the year on a balance that is not final.

206. The Commission also rejects BCP's recommendation to implement an ESM for Sierra-G at this time. The Commission agrees that the size of Sierra-G's operation does not appear to warrant the additional administrative burden that would be placed on Sierra as well as Staff, BCP, and other intervenors. BCP did not present an estimate or example calculation of the dollar amount of overearnings to support its recommendations, and a listing of prior period percentages does not provide the detail necessary for the Commission to establish an ESM for Sierra-G.

E. Affiliate Charges

Sierra's Position

207. Sierra is requesting recovery $9.06 million for affiliate charges. This includes $3.466 million of intercompany administrative services agreement ("IASA") direct costs and $4.109 million of IASA common costs, before adjustments and jurisdictional allocations. (Ex. 119 at p. 19 of 184; *see also* Schedule K-3 pgs. 1 and 2.) Sierra also seeks recovery of $1.485 million reflected as a non-recurring adjustment on I-CERT-24, specific to an intercompany billing allocation error. (Ex. 153 at I-CERT-24.)

BCP's Position

208. BCP recommends disallowing affiliate charges from BHE to Sierra in the amounts of $4.065 million for Sierra-E and $0.683 million for Sierra-G. (Ex. 404 at 2.) BCP recommends disallowing affiliate charges from MidAmerican to Sierra in the amounts of $2.997 million for Sierra-E and $0.26 million for Sierra-G. (*Id.*) BCP recommends disallowing affiliate charges from PacifiCorp to Sierra in the amounts of $0.953 million for Sierra-E and $0.144 million for Sierra-G. (*Id.*) BCP further recommends disallowing affiliate charges that were

incorrectly records to Nevada Power instead of Sierra as a Non-Recurring adjustment, in the amounts of $1.336 million for Sierra-E and $0 for Sierra-G. (*Id.*)

209. BCP also recommends that the Commission direct Sierra to file witness-sponsored schedules in future general rate cases delineating affiliate transactions clearly showing a FERC account, total charge, allocation factor, the dollar amount requested from rate payers, and a description of the charge. (*Id.*) BCP also recommends that the Commission direct Sierra to file similar schedules delineating board of director ("BOD") fees and expenses from affiliated entities and for investor relations fees and expense from affiliated entities. (*Id.* at 2-3.)

210. BCP recommends the disallowance of all affiliate charges from BHE, MidAmerican, and PacfiCorp because Sierra has failed to provide documentation to substantiate these expenses as prudent, just, and reasonable. (*Id.* at 31.) BCP states that it needs detailed invoices, gross compensation figures, and corresponding personnel titles to vet compensation charges before it recommends passing these charges on to rate payers. (*Id.*) BCP argues that by not providing such documentation, Sierra has not met the burden of proof to substantiate these charges. (*Id.* at 37.)

211. BCP argues that it is in the best interest of rate payers for Sierra to file clearly delineated and witness-sponsored schedules for BOD affiliate expenses and affiliate investor related expenses because it will give rate payers a clearer picture of what expenses are being sought for recovery, should Sierra choose to seek recovery for these expenses in future general rate cases. (*Id.* at 43-44.)

Staff's Position

212. Staff provides that the IASA governs intercompany charges and credits between BHE and its subsidiaries, including Sierra. (Ex. 321 at 19.) Staff also states that IASA costs

have steadily increased over the life of this case, due to Sierra submitting various errata to correct errors in its filings. (*Id.* at 20.) Staff notes that these charges are classified as executive costs, common executive costs, and IASA Basic Cross Charges, the last of which is incurred for the general benefit of all BHE subsidiaries. (*Id.* at 22-23.)

213. Staff states that there is a problem with identifying the dollar amounts comprising the IASA Basic Cross Charges. (*Id.* at 23.) Staff states that while the Basic Cross Charges are included in the executive and common executive costs in the schedule provided by Sierra, there is no breakdown in the schedule of what the Basic Cross Charges are as opposed to Incremental Cross Charges, which also appear in the same schedule. (*Id.* at 23-24.)

214. Staff is concerned with the number of errors and errata filed by Sierra on this issue, especially because Sierra was well aware of the errors before the end of the certification period, yet did not correct all of the errors (*Id.* at 25.) Staff provides that after all information was updated, the amount of Basic Cross Charges requested for recovery are approximately $3.711 million for Sierra-E and $66,000 for Sierra-G. (*Id.*)

215. Staff states that NV Energy (a parent of Sierra) agreed to a stipulation in Docket No. 13-07021 to limit the request for recovery of IASA Basic Cross Charges to a level less than or equal to $3.5 million (in 2014 dollars), adjusted for inflation each year through 2023. (*Id.* at 26.) Staff states that based on that stipulation, and the lack of supporting information in Sierra's request, Sierra's requested IASA Basic Cross Charges should be reduced by $1.858 million for Sierra-E and $37,000 for Sierra-G. (*Id.* at 27, 28.)

216. Staff further provides support for its reduction to the IASA Basic Cross Charges based on its disagreement with Sierra that Sierra cannot provide the documentation needed and the lack of oversight into Sierra/BHE's intercompany transactions, evidenced by the numerous

errors contained in the filings associated with intercompany transactions. (*Id.* at 32-33.) Staff is also troubled by the rapidly increasing trend in Sierra's intercompany expenses which have risen 132 percent since this issue was last addressed in Docket No. 22-06014. (*Id.* at 34.)

Sierra's Rebuttal

217. Sierra disagrees with Staff and BCP's argument that there is a lack of clarity in the discovery Sierra has provided to other parties in this docket. (Ex. 251 at 6-7.) Sierra states that it has made every effort to be transparent regarding these affiliate charges, and that its accounting methodology for affiliate charges has not changed in over a decade. (*Id.* at 7.)

218. Sierra argues that it shifted some of its IT costs to IASA, which resulted in a reduction of IT costs at the local level. (*Id.* at 8-9.)

219. Sierra argues that the 10-year agreement provision of the stipulation in Docket No. 13-07021 has expired and therefore maintains that all charges under the IASA requested for recovery are reasonable and prudent. (*Id.* at 11.)

Commission Discussion and Findings

220. The Commission finds that the stipulation entered into by Sierra and accepted in Docket No. 13-07021 included a cap on the basic cross-charges because there was uncertainty about the charges that would be pushed down from affiliates. The Commission approved a 10-year timeframe to allow the audit process to repeat itself a few times over that span, which would allow all parties to become familiar with the process. In addition to the provision for the 10-year cap, the stipulated settlement established other commitments that NV Energy would adhere to. Specifically, Commitment #28 of the stipulation in Docket No. 13-07021 provides for NV Energy to "cooperate fully with the Commission's, Staff's, or BCP's audits of the accounting

records of the Nevada Utilities, NV Energy and of MidAmerican and its subsidiaries relevant to matters within the jurisdiction of the Commission."

221. The Commission finds that Sierra did not meet its obligation to provide adequate information in this docket to satisfy the investigatory and audit needs of the intervenors.

222. Although the provision for a 10-year cap of basic cross-charges contained in Commitment #27 of Docket No. 13-07021 has expired, its concluding sentence, which reads "nothing in this paragraph shall limit any Signatory's ability to review or propose an adjustment to IASA Basic Cross Charge costs," did not expire. So, while some portion (perhaps all) of the basic cross-charges could have been prudently incurred, Sierra's inability to provide Staff and BCP with adequate information to verify what that portion is presents a difficult circumstance.

223. The Commission declines to find that a complete disallowance of the basic cross-charges is appropriate and instead finds that the capping of those charges, consistent with the methodology followed for the preceding decade, presents a reasonable outcome in this instance. Regarding the basic cross-charges, the Commission agrees with Staff's recommendation to disallow recovery of $1.858 million in affiliate basic cross-charges for Sierra-E and $37,000 for Sierra-G in this general rate case, based on prior approved amounts adjusted for inflation. The Commission accordingly finds that the cap on the basic cross-charges should remain until Sierra can demonstrate that it can meet all other requirements of the stipulation in Docket No. 13-07021.

224. The Commission further agrees with Staff and BCP that Sierra has not met its burden to demonstrate that all of the other affiliate charges were prudently incurred. Therefore, the Commission also disallows all of the incremental cross-charges sought for recovery for both Sierra-E and Sierra-G at this time. Those amounts, however, may be held in abeyance, without

carry charges, and brought forward for recovery when Sierra can adequately demonstrate that their inclusion into rates for recovery is just and reasonable.

225. The Commission finds that any affiliate charges held in abeyance should be recorded in FERC Account 186.

226. The Commission orders Sierra, Staff, and the BCP to have informal discussions to address what information should be expected to be provided by Sierra to satisfy Staff and BCP's investigatory and audit responsibilities. Those parties are further ordered to provide an informational report as a compliance item in this docket to apprise the Commission of any progress or impasse that the parties encounter. The parties should endeavor to provide the information to the Commission within a timeframe that would allow the Commission and the parties to consider the circumstances of the report as soon as practicable and with enough time for Sierra to satisfy the expectations of Staff and the BCP.

F. Valmy Retirement

BCP's Position

227. BCP states that Sierra lists the book value of the remaining Valmy plant assets at $33 million, but that Sierra has not listed the coal assets of the plant that will be retired. (Ex. 402 at 9.) BCP states that it does not know the value of the coal machinery to be retired, but estimates that it will be a significant percentage of the $33 million. (*Id.* at 11.)

228. BCP states that the rate base assets and the spare parts from the Valmy power plant leftover after its conversion to natural gas be placed in a regulatory liability account because they are no longer used and useful and amortized over 3 years. (*Id.* at 9.) BCP recommends that the remaining value of these assets be refunded to customers over a 3-year period. (*Id.* at 11.)

Sierra's Rebuttal

229. Sierra states that BCP is mistaken about which specific parts will be retired after the Valmy plant's conversion, as several of the named parts will still be needed for continuous operation at Valmy. (Ex. 242 at 5.) Sierra states that, with a few exceptions, Sierra cannot determine the totality of which specific equipment will be retired at this time; however, Sierra states that it will follow proper accounting processes when the time comes. (*Id.* at 6.)

230. Sierra disagrees with BCP's assertion that the net book value of the Valmy assets should be placed in a regulatory liability account, but rather a regulatory asset account. (Ex. 240 at 6.) Sierra disagrees because this method of accounting for retired assets in the past, and because the Commission approved this method of accounting in its order to the 5th Amendment to the Integrated Resource Plan. (*Id.* at 6.)

Commission Discussion and Findings

231. The Commission agrees with Sierra and finds that it is reasonable to record the net book value ("NBV") of assets retired as part of the Valmy conversion into a regulatory asset account. However, the Commission also finds that Sierra should record appropriate offsets in the regulatory asset account. As the assets to be potentially retired during the conversion are presumably included in the rate base sought for recovery and will be included in the rates determined in this general rate case, the Commission envisions that, at a minimum, some of the appropriate offsets would include the revenue requirement components associated with those retired assets, as determined in this general rate case.

232. The Commission authorizes Sierra to record the NBV of retired assets as part of the Valmy conversion project, as well as any appropriate offsets, to a FERC 182.3 account, with carry charges.

G. Valmy Blower Fan

Sierra's Position

233. Sierra is seeking recovery of costs associated with a fan motor used at the Valmy plant, in the amount of $393,736.96. (Ex. 155 at Hanshew-Direct 2.)

Staff's Position

234. Staff recommends that the Commission reject the inclusion of approximately $394,000 for the cost of the Valmy Unit 1 2500 Horsepower fan motor ("fan motor") from inclusion in rates for Sierra-E, as the fan motor was not installed and not in use by the end of the certification period. (Ex. 315 at 15.) Staff further states that it is unclear how Sierra is classifying this expense, as to whether it was a spare part, or a part needed for work in progress. (*Id.* at 15-16.) Staff states that Sierra ultimately clarified that it was not a spare part and would be installed in May 2024, but it was not installed by the end of the certification period on February 29, 2024. (*Id.* at 16.)

235. Staff recommends disallowing $0.394 million from the Sierra-E rate base for the fan motor. (Ex. 320 at 4.)

Sierra's Rebuttal

236. Sierra disagrees with Staff's recommendation to disallow recovery the fan motor because it was purchased and received prior to the end of the certification period. (Ex. 242 at 2.) Sierra states that the fan motor was purchased as a spare, and that two fans are needed for Valmy Unit 1 to reach full load, and that a spare motor is key for the reliability of service. (*Id.* at 2-3.) Sierra states that because the fan was purchased as a capital spare within the certification period, the costs associated with the purchase of the fan are recoverable. (*Id.* at 4.)

Commission Discussion and Findings

237. The Commission finds that it is reasonable for Sierra to recover $393,736.96 for the cost of the Valmy blower fan, but the Commission disallows recovery of any installation costs as they should be included in Sierra's next general rate case.

H. Valmy/Tracy Depreciation

Sierra's Position

238. Sierra states that it uses the straight-line method of depreciation accounting, with one-twelfth of the annual Commission-approved rates applied to the primary account level to the prior month balances to produce the current month's depreciation expense. (Ex. 101 at Schedule G-3.)

239. Sierra states that not all assets at the Valmy plant are going to be retired as of December 31, 2025, and not all assets to be retired will be fully depreciated by that date either. (Ex. 155 at 11-12.) Sierra states that the NBV at the time of retirement is $33 million. (*Id.* at 12.) Sierra states that the depreciation rates will need to be changed in accordance with the new proposed life of 24 years in Docket No. 23-08015, but it is difficult to determine how much depreciation expenses will change at this time. (*Id.* at 12-13.)

240. Sierra states that, due to the difficulty of knowing how much depreciation rates will change over time, it is therefore requesting that it be allowed to create a regulatory asset for the remaining net book value of the Valmy plant assets slated for retirement. (*Id.* at 13.) Sierra expects that annualized depreciation expenses in 2026 to be equal to the depreciation expense included in the instant Docket, and Sierra therefore states that a specific Valmy depreciation adjustment will be necessary. (*Id.*)

Staff's Position

241. Staff recommends that the Commission adjust the depreciation rate for Valmy Units 1 and 2 to reflect the Commission's order in Docket No. 23-08015, which approved a retirement date through 2049, resulting in an estimated decrease of $23 million to Sierra-E's depreciation expense. (Ex. 311 at 10.)

242. Staff justifies this decrease by re-calculating the depreciation rate on a longer timeline, using the retirement year of 2049 instead of 2025. (*Id.* at 4.) Staff argues that, with all other variables being equal, Sierra would over-collect on depreciation during the current rate effective period from captive ratepayers (*Id.*) Staff states that because Sierra was previously granted its own request to extend the operational lives of these assets, its investments should be recovered over the extended lives of the assets from future ratepayers. (*Id.*) Staff notes that Sierra has not asked for a change to depreciation rates in the instant Docket. (*Id.* at 5.)

243. Staff calculates that the combined depreciation expense for Valmy Unit 1 is significantly reduced when the retirement year is changed, which results in a cost of $1,556,842, a decrease of $8,402,221. (*Id.* at 11.) Staff also calculates that the combined depreciation expense for Valmy Unit 2 similarly results in a cost of $2,709,420, a decrease of $14,900,159. (*Id.*)

244. Staff provides that in Docket No, 23-08015, the Commission ordered the Tracy 4/5 asset to extend its operations beyond 2031 to 2049. (*Id.* at 12.) Staff calculates that the depreciation expense for Tracy 4/5 based on this extended lifetime is reduced to $1,797,907, a decrease of $2,587,158. (*Id.*) Staff recommends modifying the depreciation rate for Tracy 4/5 accordingly. (*Id.* at 13.)

Sierra's Rebuttal

245. Sierra agrees with Staff's argument that an adjustment to the depreciation rate for Valmy and Tracy would be prudent. (Ex. 240 at 4.) However, Sierra seeks to include updated plant balances in its proposed proxy depreciation rates, until a new depreciation study can be done in 2028. (*Id.* at 4-5.)

Commission Discussion and Findings

246. The Commission agrees with Sierra and Staff's recommendation of an adjustment to the Valmy/Tracy depreciation rates. Sierra is ordered to adjust the rate to reflect a retirement date of 2049.

247. As a compliance item, Sierra and Staff shall coordinate on determining the appropriate depreciation expense and incorporate that adjustment into the revenue requirement of this general rate case.

I. Proposed Investigations

Staff's Position

248. Staff recommends opening an investigation to determine whether Sierra is complying with NAC 704.8823, and if it is not, whether Sierra should be assessed a penalty for not complying Commission regulations pursuant to NRS 703.380. (Ex. 313 at 19.) Staff argues that NAC 704.8823 requires Sierra to review NEM applications and provide customers with a NEM contract within 10 business days of the receipt of the application, and further requires Sierra to authorize interconnection by the customer within 10 business days after notification of complete and all required documentation is handed over to Sierra. (*Id.* at 20.)

249. Staff argues that this investigation is necessary because there is some evidence that Sierra is not reviewing NEM interconnection applications required by NAC 704.8823, based on Sierra's own admissions about how it processes the applications. (*Id.* at 21.) Staff states that

Sierra starts the 10-business day period upon receipt of all post-construction documentation, but the statute requires the 10-business day period to begin upon Sierra's receipt of the original NEM interconnection agreement. (*Id.*)

250. Staff concludes that based on complaints received from the public and Staff's ongoing investigation into Sierra's handling of NEM applications, any Commission investigation that is opened should be combined with those two other inquiries to ensure administrative efficiency. (*Id.* at 22.) Staff further concludes that if Sierra is found to be out of compliance with NAC 704.8823, the Commission should also determine if Sierra should be penalized for not complying with Commission regulation. (*Id.*)

Sierra's Rebuttal

251. Sierra recognizes that the Commission has the authority to investigate such matters but does not believe an investigation is necessary. (*Id.* at 9.) Sierra then states that while it believes it is complying with NAC 704.8823, the number of net metering applications has sharply risen since the statute was introduced in 2008, and therefore it may be beneficial to review the regulation to determine if new processes would better reflect the current net metering trends. (*Id.* at 9-10.) Sierra also anticipates filing updates to its Rule 15 interconnection tariffs, and that any investigation into Sierra's compliance with regulations can happen in a separate docket. (*Id.* at 10.)

Commission Discussion and Findings

252. The Commission declines to open an investigatory docket at this time but does, however, encourage parties to determine whether these issues can be resolved in Docket No. 24-03026. Docket No. 24-03026 pertains to similar discussions for Nevada Power, and the Commission encourages process improvements that can be adopted in both service territories. If

the issues cannot be fully addressed in Docket No. 24-03026, a separate directive from that docket may be appropriate. Alternatively, Staff may seek to petition the Commission for an investigatory docket subsequent to the final order being issued in Docket No. 24-03026.

J. Net Energy Metering ("NEM") (In General) and Net Metering Regulatory Asset

Sierra's Position

253. Sierra requests to include in rate base and amortize over three years the NEM AB 405 Regulatory Asset, totaling $3.520 million, to provide recovery of the rate difference between the general rate revenues and the rates used to establish the NMR-A rate rider, with carrying charges. (Ex. 123 at I-CERT-30.)

SEIA's Position

254. SEIA states that Sierra's proposed increase to the BSC in its rate design testimony is not really to increase bill stability for customers, but rather because of Sierra's claim that NEM customers are more expensive to serve than non-NEM customers. (Ex. 900 at 2-3.) SEIA further states that this claim is inaccurate because Sierra's cost allocation and marginal cost study ("MCS") contains fundamental flaws – including imputed load shapes that do not actually reflect NEM customers' grid use, errors in the meter cost installation expenses, and customer accounts that are poorly supported. (*Id.* at 4.)

255. SEIA states that when these flaws are corrected, NEM customers have a cost of service that is roughly 35 percent lower than non-NEM customers. (*Id.*) SEIA further states that the cost of service falls by 70 percent when the analysis includes solar plus storage ("S+S") systems. (*Id.*)

256. SEIA argues that Sierra charges NEM customers for energy Sierra delivers to them but does not credit NEM customers for the energy they provide to their neighbors, which

results in a NEM regulatory mechanism that dramatically overstates any difference that may exists between NEM cost responsibility and retail rate revenue. (*Id.* at 5.)

257. SEIA recommends that Sierra should cease using imputed load profiles for NEM customers, and instead use the SEIA-recommended load profile that couples actual energy delivered to NEM customers with a proper credit for exported energy for NEM customers' neighbors. (*Id.* at 6.) SEIA states that the imputed load profiles Sierra uses do not represent the physical reality of the grid, as the "total load profile" and "distribution load profile" approaches assume that every solar energy system vanishes and plays no part in meeting a customer's load at any point in time. (*Id.* at 22.)

258. SEIA further recommends that the Commission require Sierra to fix its NEM meter installation costs, due to Sierra only spending 30 minutes on NEM system inspections, yet charges for a full hour of labor in the derivation of its figures. (*Id.* at 6.) SEIA argues that Sierra's sole reason for the cost differential between NEM and non-NEM meters is the capitalized installation labor cost that Sierra applies only to NEM meters, despite the meters having only minimal differences in how they are installed and operated. (*Id.* at 41-42.) SEIA states that Sierra's claim that NEM meters take three times longer to install than non-NEM meters is ultimately unsupported by its testimony. (*Id.* at 43.)

259. SEIA recommends that the Commission require Sierra to update its Customer Weighting Factor Survey ("CWFS") because it currently contains many arbitrary assumptions that are not adequately explained by Sierra, and these assumptions are a major factor in the costs allocated to NEM customers. (*Id.* at 6.) SEIA recommends that Sierra should be required by the Commission to adopt a CWFS based on customer counts, or at least be required to provide more guidelines and guardrails regarding the use of the CWFS. (*Id.*)

260. SEIA recommends a few different approaches with regard to the CWFS and Sierra's methods for allocating customer accounts and services ("CAS") costs. (*Id.* at 65.) SEIA states that one approach is to eliminate the entire process and allocate CAS accounts based on a customer count basis, which would eliminate the need to perform the CWFS altogether. (*Id.* at 66.) SEIA states that if the Commission does not wish to do away with the CWFS process, it should instead require Sierra to use more consistency in its calculation methods to eliminate arbitrary decision-making based solely on prior survey results. (*Id.*)

261. SEIA recommends that the Commission require Sierra to refund to ratepayers all costs associated with the AB 405 Regulatory Asset, as it is based on the same flawed cost allocation and MCS methodology. (*Id.* at 6.) SEIA states that this kilowatt-hour mismatch between NEM and non-NEM customers has been present since the regulatory asset's inception. (*Id.* at 99.) SEIA further states that Sierra's calculations regarding the regulatory asset have been unreliable, as evidenced by Sierra needing to refund $1.5 million to ratepayers. (*Id.* at 102-103.) SEIA concedes that this is a risk for Sierra, but this risk is already compensated for through Sierra's ROE. (*Id.* at 103.)

262. SEIA recommends, should the Commission not be inclined to refund costs, that the Commission should instead require Sierra to properly credit exported energy at the cost-based rate and refund any difference caused by this error. (*Id.* at 6-7, 103.)

BCP's Position

263. BCP explains that, in Nevada Power's 2020 general rate case, the AB 405 NEM Regulatory Asset was resolved by stipulation and that the stipulation did not address whether or to what extent Nevada Power has experienced a revenue deficiency due to net metering. (Ex. 408 at 23.) Further, BCP provides that the stipulation did not defer this issue to a future proceeding

and that the Commission did not specifically address the regulatory asset either during or after the 2020 general rate case. (*Id.*)

264. BCP states that, in 2017, the Commission approved a stipulation among the parties to defer the decision regarding the NEM regulatory asset until Nevada Power's 2020 general rate case. (*Id.*) BCP maintains that because there was no further reference to maintain the NEM regulatory asset, Nevada Power's NEM regulatory asset ceased to exist at the conclusion of that proceeding. (*Id.*) Accordingly, BCP recommends that the Commission reject Sierra's proposed recovery of the NEM regulatory asset in this proceeding and adjust Sierra's rate base and amortization expense by $3.250 million and $115,000, respectively. (*Id.* at 24-25.)

Staff's Position

265. Staff provides that Sierra requires a customer to provide the contract that the customer entered into with its solar photovoltaic ("PV") installer when applying for a NEM interconnection, with Staff noting that the rule only applies to customers who are going to receive an incentive from the NEM interconnection. (Ex. 313 at 16.) Staff states, however, that Sierra requires copies of contracts for all NEM interconnection applications. (*Id.*)

266. Staff disagrees with the various rationale provided by Sierra for why Sierra requires copies of all NEM interconnection agreements. (*Id.* at 17.) Staff states that there is no statutory provision for this requirement, Sierra has no authority to enforce statutes outside of its purview, and Sierra did not review every NEM interconnection application that it received during the test period within 10 business days, as it is required to do by NAC 704.8823. (*Id.*) Staff argues that Sierra should not be delaying the connection of NEM systems by reviewing items not within its statutory purview. (*Id.*) Staff therefore recommends that the Commission

order Sierra to cease requiring customers to provide copies of their contracts with solar PV contractors. (*Id.* at 18.)

267. Staff also disagrees with the $3,174,415 in costs plus carrying charges of $345,975 requested for recovery by Sierra as associated with the NEM AB405 Regulatory Asset. (Ex. 318 at 6.) Staff disagrees with the costs requested because Sierra did not request an extension of the NEM Regulatory Asset in Sierra's 2019 general rate case (Docket No. 19-06002) or the 2020 Nevada Power general rate case (Docket No. 20-06003). (*Id.*) Staff states that the Commission did not grant an extension in either of those dockets, nor was an extension even discussed. (*Id.*) Staff further states that the Commission did not authorize the NEM Regulatory Asset going forward in Nevada Power's most recent general rate case, Docket No. 23-06007. (*Id.* at 7.)

268. Staff argues that regulatory asset treatment for AB 405 ended for Sierra in 2019, as Sierra had no basis to believe that the regulatory asset methodology would be allowed to continue, and the Commission should deny recovery of these costs in the instant proceeding. (*Id.*) Staff concludes that the Commission should deny recovery of the NEM AB405 Regulatory Asset, removing $3.520 million from rate base and $1.173 million from amortization expense. (*Id.* at 8.)

Sierra's Rebuttal

269. Sierra asserts that the AB 405 NEM Regulatory Asset has a record of continuous Commission approval in Sierra's prior general rate cases – Docket Nos. 19-06002 and 22-06014. (Ex. 251 at 14.) Sierra adds that the NEM Regulatory Asset was also approved in Nevada Power's most recent general rate case, Docket No. 23-06007. (*Id.* at 14.) Sierra states that the facts and circumstances in the instant docket are similar to those in Docket No. 23-06007, and

that Sierra had no basis to believe that the regulatory asset methodology would cease to continue. (*Id.* at 14-15.) Sierra therefore recommends that, because the facts and circumstances in this Docket are consistent with those in 23-06007, the Commission should act consistently here. (*Id.* at 15.)

270. Sierra further states that that the Marginal Cost Study ("MCS") is not the source of the cost-based rates used in the calculation of the NEM Regulatory Asset. (Ex. 239 at 2.) Sierra states that its calculations of the NEM Regulatory Asset includes the balance of the previously approved I-CERT-30 from Docket No. 22-06014, and that the NEM Regulatory Asset in this case should contain adjustments and associated carry charges. (*Id.*)

271. Sierra states that Staff's argument that Sierra has no statutory authority to collect a customer's PV contract is not a sufficient reason to prevent Sierra from verifying information related to its net energy metering ("NEM") projects. (Ex. 238 at 3.) Sierra states that it is important to consider the original intent behind this requirement in NAC 701B.155, and whether it is still applicable to today's non-incentive NEM interconnection process. (*Id.* at 3-4.) Sierra states that this provision was introduced and approved in Docket No. 09-07014, and it was designed to eliminate the majority of NEM applicants that only have a marginal interest or no serious intent to move forward with installation, which required Sierra to expend time and resources that were ultimately not needed. (*Id.* at 4.)

272. Sierra states that obtaining a copy of a customer's signed solar PV contract provides a credible source of information containing the generating size agreed upon by the customer and solar contractor, and that generation size is a key variable in determining Schedule NMR-405 versus Schedule NMR-B rates. (*Id.* at 5-6.) Sierra states that calculating generation

size is dependent on the reviewing of the PV contract, as the review of such contracts helps detect data entry errors that Sierra cannot otherwise verify. (*Id.* at 6.)

273. Sierra further states that, per the Commission's order in Docket No. 21-05013, Sierra is required to include in its application process a document signed by both the owner and renter that allows the renter to install a NEM system, which can be used by Sierra to verify if the owner of a property is aware of a NEM system installation. (*Id.* at 6-7.)

274. Sierra states that Staff did not incorporate the corresponding ADIT impacts of disallowing the entire NEM regulatory asset. (Ex. 250 at 6.) Sierra states that if the Commission is to disallow costs associated with the NEM regulatory asset, $739,000 of ADIT should be included in that calculation. (Ex. 234 at 4.)

Commission Discussion and Findings

275. The Commission finds that the AB 405 NEM Regulatory Asset was initiated in Nevada Power's 2017 general rate case as a methodology to allow for implementation of the statutory requirements of AB 405 while holding Nevada Power harmless for any potential general rate case revenue shortfall. Sierra followed this methodology and requested recovery of the AB 405 NEM Regulatory Asset in its 2019 and 2022 general rate case applications, Docket Nos. 19-06002 and 22-06014, respectively. The existence and amount of the NEM potential shortfall has been discussed, litigated, and reviewed in dockets going back to Docket Nos. 15-07041 and 15-07042, and was discussed in Sierra's general rate case, Docket No. 16-06006, prior to AB 405 being signed into law. While rates are set in a general rate case docket to take any potential NEM general rate case revenue shortfall into consideration as of the end of the certification period, these rates do not in themselves account for any incremental NEM

customers after that date and in the rate-effective period (i.e., those who subsequently take service pursuant to Sierra's AB 405 tariff).

276. The Commission finds that the revenue requirement portion of Docket No. 19-06002 was settled without any discussion with respect to the AB 405 NEM Regulatory Asset in the Stipulation. Adjustments to other regulatory assets were specifically identified, and a black-box adjustment was agreed to as well. In Docket No. 22-06014, the AB 405 NEM Regulatory Asset was listed in the Modified Final Order, but only to the extent of referencing BCP's recommendation to lengthen the amortization period for other regulatory assets. No party in the 2022 docket made any recommendations with respect to the AB 405 NEM Regulatory Asset, and there is no explicit indication in the Order in Docket No. 17-06003 as to whether that regulatory asset approval was to expire or if it would be evergreen.

277. Sierra is requesting to recover an AB 405 NEM Regulatory Asset in the amount of $3,520,390, including $345,975 in carry charges, amortized over three years. The Commission finds that Sierra shall exclude carrying charges on the regulatory asset and recover $3,174,415 amortized over three years at $1,058,138 per year. In addition, the Commission finds that the regulatory asset balance of $3,174,415 shall not be included in rate base for the purposes of determining the revenue requirement.

278. The Commission declines to adjust the calculation of the AB 405 NEM Regulatory Asset as recommended by SEIA. That calculation was based upon the approved cost-of-service study in Docket No. 22-06014, and the Commission declines to revisit that approval here.

279. The Commission recognizes that the AB 405 NEM Regulatory Asset is not a traditional regulatory asset in that it does not reflect recorded costs as they are incurred, as is the

case with other regulatory assets or regulatory liabilities. The amounts recorded in the AB 405 NEM Regulatory Asset are based on the assumptions and cost allocations of cost of service from an approved cost-of-service study. It is a calculated revenue shortfall based on that information at a singular point in time using the approved cost of service. It may not reflect current costs or any incremental revenues and is subject to changes in any of the estimates or other data underlying the cost of service which may subsequently occur.

280. The Commission finds that carry charges should not accrue on the AB 405 NEM Regulatory Asset as the calculation already includes a return component. It is not appropriate for this regulatory asset to earn a return on the return and compound the revenues calculated in the regulatory asset. Similarly, the Commission finds that the balance of the AB 405 NEM Regulatory Asset should not be included in rate base as that would also provide a compounding of returns on the revenues calculated.

281. Sierra is also ordered to cease recording any amounts to the AB 405 NEM Regulatory Asset subsequent to the end of the certification period. The Commission is not authorizing the AB 405 NEM Regulatory Asset going forward. Any future attempt by Sierra to address a revenue shortfall related to NEM should include methodologies that continue to support the objectives of AB 405 and provide the least impact to non-participating customers.

282. Lastly, the Commission agrees with Staff that Sierra should not require the executed contract with the NEM installer to be provided at the time of applying for NEM interconnection. There is no statutory or regulatory basis to do so absent the previous program incentives. That said, the Commission does agree with Sierra that these contracts are required to be filed for those systems where the property is rented to verify that the property owner is aware of and authorizes the proposed installation.

K. Various Process and Procedure Enhancements

<u>*NEM Application Fee*</u>

Sierra's Position

283. Sierra proposes a new fixed fee of $184 for net metering systems whose capacity is less than or equal to one MW alternating current. (Ex. 202 at 11.) Sierra states that the proposed fee reflects the projected application processing costs and projected volume of submitted applications from Sierra customers collected in a balancing account. (*Id.* at 11.) Sierra states that the proposed $184 application fee is intended to cover the higher costs of maintaining the Rule No. 15 tariff's interconnection process. (*Id.*) The intention of the balancing account is to match as closely as possible the interconnection process's costs with an equal amount of fee collection to result in an ideal zero, or close to zero, balance. (*Id.*)

284. Sierra states it has seen an increase of net metering applications by 164 percent since 2021 which results in incremental costs from the higher incoming volume as well as the external contract and internal resource demand to meet the ten-day business day timeline required by NAC 704.8823. (*Id.*) Sierra also cites increased software costs including the application workflow management software and the online cost estimation calculator tool hosted on NV Energy's website. (*Id.* at 12.) Sierra has also experienced higher volume of interconnection applications with errors requiring more resources to assist applicants in resolving those errors within the same mandated ten-business day review period. (*Id.*)

285. Sierra states that it is shifting a higher portion of application costs to the balancing account due to the renewable energy incentive programs upcoming retirement of December 31, 2025. (*Id.*) Historically, net metering application costs have been split between the Renewable Energy Programs' REPR rate and the balancing account. (*Id.*) Sierra states that the balancing

account share will be 93 percent starting July 1, 2024, through June 30, 2025, up from 87 percent in the time period July 1, 2023, through June 30, 2024. (*Id.*) Sierra states that it has committed to reinstituting solar contractor and stakeholder workshops to ensure the market participants understand the net energy metering application and interconnection process. (*Id.* at 13.) Sierra states that it also intends to propose an update to Rule No. 15 in 2024 to modernize the interconnection standards and propose new processes that could alleviate common errors. (*Id.*)

SEIA's Position

286. SEIA states that the Commission is not required to approve the increase in NEM application fees from $84 to $184, and SEIA then further argues that Sierra has not sufficiently supported and justified the costs that drive the request to increase the NEM application fee. (Ex. 900 at 123.)

287. SEIA states that the application processing contract that Sierra has extended appears to be more expensive than its prior contract, despite the underlying process remaining identical. (*Id.* at 124.) SEIA states that the projected increase in application volume has not yet materialized and has actually decreased from the end of 2023 and into the beginning of 2024. (*Id.*)

288. SEIA states that Sierra has not been able to support its claim with data that new market entrants are increasing the number of applications submitted with errors. (*Id.*) SEIA also states that Sierra's position on the ten-business day review period for applications has changed over the life of this case, and as a result it is unclear whether Sierra must comply with the ten-business day requirement. (*Id.*) SEIA also states that any costs associated with the WattPlan website should be disallowed until Sierra modifies the tool to increase transparency and reduce the bias associated with it. (*Id.*)

289. SEIA recommends that the Commission reject the NEM application fee increase and that the Commission should thoroughly scrutinize contract costs submitted for recovery. (*Id.*) SEIA argues that the sizable jump in processing costs and application software costs are not consistent with the projected increase in applications nor is it related to additional complexity of the application process. (*Id.*)

Staff's Position

290. Staff recommends modifying Sierra's Rule No. 15 to include the following provision in section D(1):

> "An application containing errors or omission that are not rectified after two iterative utility reviews shall be rejected and the applicant must submit a new completed application and remit a fee for process the new completed application to the utility." (Ex. 313 at 18-19.)

291. Staff states that it does not object to Sierra increasing the fee to apply for NEM interconnection under Rule 15 from $84 to $184, but it does have concerns regarding the high number of NEM interconnection applications submitted with errors. (*Id.* at 18.) Staff states that Sierra is required to expend additional funds to process and correct the applications due to the number of errors. (*Id.* at 19.)

292. Staff recommends that those applicants who submit NEM applications with errors should bear the cost of correcting those errors, not ratepayers or NEM applicants as a whole. (*Id.*) Staff states that modifying Rule 15 to reflect the above aligns the cost of review to those customers who cause the increased costs. (*Id.*)

Sierra's Rebuttal

293. Sierra agrees with Staff's proposition to modify Sierra's Rule 15 to terminate net metering applications with repetitive errors, and then requiring applicants to pay additional fees. (Ex. 238 at 7-8.) Sierra states that it agrees with Staff's recommendation to terminate a net

metering application after two iterative reviews because it would reduce costs associated with repetitive reviews. (*Id.* at 8.) Sierra states that this change to its policies could reduce the application fee by all net metering applicants because more fees would be collected from applicants that contain repetitive errors. (*Id.*)

294. Sierra stands by its usage of the web-based WattPlan tool and states that it helps customers estimate the cost of setting up and operating a net metering system. (*Id.* at 10.) Sierra states that WattPlan allows customers to adjust values and input assumptions to personalize the results. (*Id.* at 12.) Sierra states that the user can see the initial values that WattPlan's calculator uses for system cost, maintenance, loan interest rate, lease, and PPA. (*Id.*) Sierra maintains that the WattPlan is a helpful tool for customers, and that costs associated with it should be allowed for recovery. (*Id.* at 13.)

295. Sierra states that it only extended its application processing contract as the contract was due to expire, and not because of an increase in NEM applications submitted. (*Id.* at 14.) Sierra states that the reason for the price increase triggered a renewal of the contractor's pricing schedule, and the costs reflect the price differences between 2020 and 2024. (*Id.*) Sierra states that it is evaluating several options to keep application fee costs down, including soliciting competitive bids from various contractors and seeking out new technology that can automate various parts of the application process. (*Id.* at 14-15.)

296. Sierra states that the reasons for the increase in the NEM application fee is due to 2024 contractor costs of doing business, and because the projected increase in the number of applications increases the variable costs on a per-application basis. (*Id.* at 19-20.) Sierra states that if the Commission declines to increase the application fee in this general rate case, it would

lead to a negative balance in Sierra's regulatory balancing account, thus requiring Sierra to ask for an even higher application fee increase in its next general rate case filing. (*Id.* at 20.)

Commission Discussion and Findings

297. The Commission accepts Sierra's proposed increase to NEM application fees, from $84 to $184. Applications for NEM have increased substantially, causing a strain on all resources dedicated to the NEM process. Sierra has demonstrated its willingness to resolve application issues with customers and electrical contractors.

298. The Commission agrees with the parties regarding the modifications to Rule 15 proposed by Staff. When customers or electrical contractors are non-responsive or fail to provide sufficient information to process the NEM application after the second iterative review, Sierra should have the right to terminate the application.

299. In order to implement these Rule 15 modifications, the Commission directs Sierra to file a tariff modification request to incorporate the changes agreed to by the parties. Sierra must also work with the parties to include application termination metrics into existing or future NEM application reporting.

Capitalization Threshold

BCP's Position

300. BCP provides that Sierra uses a $500 capitalization threshold, which is used as a benchmark for qualifying purchases. (Ex. 403 at 6.) BCP further provides that a purchase above the threshold is recorded as a capital asset, and a purchase below the threshold is charged as an incurred expense. (*Id.*) BCP states that Sierra's capitalization threshold does not consider rising prices due to inflation. (*Id.*)

301. BCP states that while a threshold level can vary depending on the size of a given company, the Internal Revenue Service provides that a company with audited financial statements may use $5,000 as the threshold dollar amount. BCP states that Sierra qualifies for this threshold because it is a publicly traded company with audited financial statements. (*Id.*)

302. BCP argues that ratepayers would benefit from a higher threshold because it will reduce the amount capitalized to plant assets for small and *de minimis* items. (*Id.*) BCP argues that Sierra would also benefit from an increased threshold because it will reduce Sierra's administrative burden to record and track *de minimis* purchases, accumulated depreciation, and deferred taxes. (*Id.* at 6-7.)

303. BCP recommends that the Commission direct Sierra to increase the dollar amount threshold to $5,000 and continue to adjust the dollar threshold as it relates to inflation. (*Id.* at 7.)

Sierra's Rebuttal

304. Sierra disagrees with BCP's argument to increase Sierra's capitalization threshold from $500 to $5,000. (Ex. 240 at 8.) Sierra disagrees because this threshold is based on an IRS Notice which suggests that a company with audited financial statements (such as Sierra) may use the $5,000 threshold, but it is not required. (*Id.* at 8-9.) Sierra is concerned that this increase would also increase the expense revenue requirement, which is not included in the current general rate case. (*Id.* at 9.)

Commission Discussion and Findings

305. The Commission declines to accept BCP's recommendation to increase Sierra's capitalization threshold. The Commission has adopted by reference the federal Uniform System of Accounts ("USOA") in NAC 704.650, and Sierra abides by these account definitions. The

USOA capitalization threshold is $500, and the Commission declines to make any changes to that at this time.

L. Excess Liability Insurance (Allocation and Regulatory Asset)

Sierra's Position

306. Sierra provides that the allocable share of the annualized cost of property insurance for Sierra-E has increased to $462,000, with the annual cost of excess liability insurance increasing to $13,446,000. (Ex. 209 at 2-3.) Sierra states that the annual cost of fiduciary liability insurance remains at $19,000. (*Id.* at 3.) Sierra further provides that its allocable share of the annualized cost of property insurance for Sierra-G has increased to $38,000, with the annual cost of excess liability insurance increasing to $1,914,000. (*Id.*) Sierra states that the annual cost of fiduciary liability insurance has remained at $3,000. (*Id.*)

307. Sierra states that the annualized cost of property insurance has increased due to Sierra's property values increasing slightly relative to other BHE assets and inflation. (*Id.*) Sierra states that the annualized cost of excess liability insurance has increased due to the rising cost of wildfire coverage, and due to Sierra's decision to purchase stand-alone liability insurance that provides Sierra with $150 million in exclusive excess liability limits, $100 million of which can be used for wildfire claims. (*Id.* at 4.)

308. Sierra states that the prolonged drought conditions, paired with increased development in wildland areas, has led to more frequent and more destructive wildfires in recent years, which results in significant increases to wildfire costs for utilities. (*Id.*) Sierra states that in the past, it would participate in shared liability coverage with other BHE businesses, but the limits of that coverage required Sierra to purchase additional excess liability insurance. (*Id.* at 5.)

Sierra states that it purchased this additional insurance as a necessary component of operating a utility. (*Id.* at 6.)

309. Sierra states that even the most reasonable and prudent of practices by utilities cannot fully eliminate wildfire risks, and physical mitigation must be accompanied by financial resiliency to withstand these severe events. (Ex. 215 at 8.) Sierra then lists other examples of how regulators in other regions have handled this issue, and the examples given all involve regulatory acknowledgment of higher and more uncertain wildfire insurance cots, regulatory recognition of exogenous drivers, and cost deferral mechanisms. (*Id.* at 14.)

310. Sierra states that these increased costs are appropriate to be recorded in a regulatory asset because, otherwise, Sierra will have no opportunity to recover extraordinary costs once they are incurred. (*Id.* at 21.) Sierra states that it can expect to incur $8 million in unrecovered costs for excess liability insurance (including wildfires) through September 2024. (*Id.* at 22.) Sierra states that this corresponds to annualized total premiums of $10 million, or approximately 5 percent of Sierra's O&M expenses. (*Id.*)

SEA's Position

311. SEA states that Sierra is requesting a $96,223,000 increase to revenue requirement, and a major portion of that increase ($13,563,000) is related to Sierra's liability insurance costs. (Ex. 701 at 1-2.) SEA disagrees with Sierra's assertion that closely aligning the timing of cost-recovery of these incremental costs with the timing of when the benefit is utilized by customers justifies a retroactive deferral. (*Id.* at 2.)

312. SEA states that Sierra is taking a company-friendly approach by not modeling a carrying cost for the customers and instead including the entirety of the proposed regulatory asset

balance in the rate base. (*Id.*) SEA states that this benefits Sierra because the rate-base balances do not decline over the rate-effective period during which the amounts are amortized. (*Id.*)

313. SEA states that there is no justification for Sierra to cover costs on a retroactive basis, whether rates have gone up or not. (*Id.* at 3.) SEA argues that the proper method to adjust for cost increases is for Sierra to file a rate case and adjust rates holistically on a forward-looking basis. (*Id.*)

314. SEA is concerned that gross negligence findings in recent lawsuits against PacifiCorp (a subsidiary of BHE, Sierra's parent company) are part of the reason why Sierra's insurance premiums have gone up. (*Id.*) SEA is concerned about this because the cost of negligence claims arising from lawsuits would not be borne by ratepayers, but the cost of insurance policies are typically borne by ratepayers. (*Id.*) SEA questions whether Sierra is attempting to insure its ROE against acts of imprudence. (*Id.* at 3-4.)

BCP's Position

315. BCP notes that Sierra is requesting a regulatory asset for the insurance increase in the test year in the amount of $12.260 million. (Ex. 408 at 15.) BCP states that regulatory tracking mechanisms, such as regulatory assets, are usually reserved for cost increases that are outside the control of management, and insurance policy costs are not the type of costs that fit the criteria for regulatory tracker treatment. (*Id.* at 16.)

316. BCP cites to the National Regulatory Research Institute's criteria, and notes that all criteria (cost is outside the control of the company, it is unpredictable and volatile, and it is substantial and recurring, while causing severe financial consequences to the company) must be met for a cost to qualify for regulatory-asset treatment. (*Id.*) BCP notes that insurance policy

costs meet none of these criteria, and that there is no need to retroactively capture costs that have already occurred and then defer them for collection later. (*Id.* at 17.)

317. BCP recommends that the Commission reject Sierra's request for a regulatory asset for the increase in excess liability insurance costs, which would reduce the jurisdictional rate base by $12.260 million, and further reduce the related amortization expense by $4.087 million. (*Id.* at 20.) BCP recommends in the alternative that the Commission should share the costs of the excess liability policy evenly between shareholders and ratepayers. (*Id.* at 21.)

Staff's Position

318. Staff provides that Sierra is requesting to include $13,562,990 in its rate base for its excess liability cost increase regulatory asset, to be amortized over three years. (Ex. 318 at 8.) Staff states that Sierra calculates this cost as being the difference between the cost of insurance approved in the 2022 general rate case and the amount requested for recovery in the current filing. (*Id.*) Staff states that if approved as requested, Sierra would not only be receiving $21.678 million for the recovery of excess liability insurance costs as an expense, but also an additional $12.260 million in rate base earning a rate of return. (*Id.*)

319. Staff states that this level of recovery is excessive, as insurance rates have gone up minimally in 2024, so there is little in the way of regulatory lag. (*Id.* at 8-9.) Staff notes that Sierra is already requesting full recovery of insurance rates going forward, so for Sierra to request additional funds for amounts it has or will incur is unjustified and burdensome to ratepayers. (*Id.* at 9.) Staff further notes that excess liability insurance costs are classified as administrative expenses and are considered to occur in the normal course of business, which are not usually included in rate base. (*Id.*)

320. Staff therefore recommends that the Commission deny recovery of Sierra-E's excess liability insurance costs as a regulatory asset, removing $12.260 million from rate base and $4.087 million from amortization expenses. (*Id.*)

321. Staff also provides that, traditionally, BHE has been the provider of wildfire insurance for Sierra. (Ex. 313 at 4.) However, Staff also notes that Sierra has secured additional wildfire insurance policies in recent times through third parties due to Sierra's concerns about an increased risk of wildfire. (*Id.* at 4.) Staff states that NV Energy, as the holding company that owns Nevada Power and Sierra, is the named insurer for the standalone excess liability insurance policies. (*Id.* at 5.)

322. Staff is concerned about the impact of the policy on Nevada Power ratepayers, as Sierra's wildfire risk (due to its service territory) is much higher than Nevada Power's. (*Id.*) Staff is further concerned by the lack of discussion in Sierra's application as to how wildfire claims against Sierra could affect Nevada Power or its ratepayers, and Staff calls for Sierra to address this issue on rebuttal. (*Id.*)

323. Staff points out Sierra's concession that in the event of catastrophic wildfire, liabilities can possibly exceed the insurance coverage limits now available. (*Id.* at 6.) Staff states that because of this, some of the cost of procuring excess liability insurance should be borne by the shareholders. (*Id.* at 7.) Staff further argues that because shareholders benefit from the excess liability insurance, they should be allocated a portion of the costs of annual premiums. (*Id.*)

324. Staff recommends that Sierra's shareholders should be allocated 50 percent of the costs of the excess liability insurance policies. (*Id.* at 8.) Staff states that the result of this

adjustment is a decrease of $8.19 million for Sierra-E and a decrease of $0.86 million for Sierra-G. (*Id.*)

325. Staff agrees with Sierra's proposal to allocate the costs of the premiums for wildfire-only insurance policies at 76 percent for Sierra and 24 percent for Nevada Power. (*Id.* at 9.) Staff states that the 76/24 allocation for these costs appears to be reasonable based on each company's respective wildfire risk. (*Id.* at 10.) Staff does state, however, that for general insurance premiums that also include wildfire risk, Sierra's proposed allocation of 42 percent to Sierra and 58 percent to Nevada Power is not sufficient. (*Id.*) Staff states that because both of these kinds of premiums address wildfire risk, the allocation should be the same – 76 percent for Sierra and 24 percent for Nevada Power. (*Id.*)

326. Staff states that the result of this adjustment is an increase in the revenue requirement for Sierra-E of $2.68 million and an increase of $0.311 million for Sierra-G. (*Id.* at 11, 12.)

Sierra's Rebuttal

327. Sierra states that Staff's recommendations on this subject are conflicting because one Staff witness calls for a regulatory liability for any over-collection of insurance costs, while another Staff witness wants to deny a regulatory asset when Sierra under-collects insurance costs, which is punitive to Sierra. (Ex. 252 at 14.)

328. Sierra maintains that a regulatory asset is justified for the tracking of insurance costs going forward between rate cases. (*Id.* at 16.) Sierra states that the unique volatility of wildfire insurance creates the need for a unique recovery methodology to monitor and recover all insurance costs, and states that the overcollection would also need to be tracked. (*Id.* at 17). Sierra states that this effectively establishes a balancing account for insurance costs. (*Id.*)

329. Sierra disagrees with Staff and BCP's argument for a splitting of the costs of excess liability insurance between shareholders and customers. (Ex. 236 at 2.) Sierra states that aside from director and officer ("D&O") liability insurance, Sierra's other insurance costs have never been equally split between shareholders and customers. (*Id.* at 2.) Sierra states that the key difference between D&O insurance costs and excess liability insurance costs is that shareholders can directly benefit as claimants under the D&O insurance policy but cannot do so under excess liability insurance. (*Id.* at 3.) Sierra states that Nevada Power, Sierra, and the customers of both utilities benefit from the cost-savings of shared insurance policies. (*Id.* at 4.) Sierra recommends that the Commission reject the proposals from Staff and BCP to split excess liability insurance costs evenly between shareholders and customers, as Staff and BCP provide no basis for changing those allocations. (*Id.* at 5.)

330. Sierra further states that Staff's witness used the incorrect values when calculating the impact on Sierra's revenue requirement. (Ex. 250 at 12.) Sierra states that applying the appropriate jurisdictional allocator for Sierra-E results in a total revenue requirement of $14.939 million, one half of which would be a reduction of $7.470 million. For Sierra-G, the result is a reduction of $0.868 million. (*Id.*) Sierra states that the insurance prepaid, with the proper jurisdictional allocator applied, results in a $1.085-million reduction in rate base for Sierra-E and $0.123 million for Sierra-G. (*Id.* at 13.)

331. Sierra notes that the current excess liability insurance allocation is 32 percent for Sierra and 68 percent for Nevada Power. (*Id.*) Sierra states that moving to a 76/24 Sierra-to-Nevada-Power allocator would result in a $12.916-million increase to revenue requirement for Sierra-E, and an increase of $1.5 million to revenue requirement for Sierra-G. (*Id.* at 14.)

Commission Discussion and Findings

Excess Liability Regulatory Asset

332. The Commission rejects Sierra's request for a retroactive regulatory asset for wildfire insurance premium costs already incurred. The fact that a cost has increased is not a reason to establish a regulatory asset on a retroactive basis. The increased insurance rates went into effect in August 2023 with additional cost-increases incurred during the certification period. The Commission agrees that the normal course of action for a utility to address cost increases and the ability to earn its authorized return is to file a general rate case and adjust rates holistically. Sierra did that in this case in February 2024, which will provide for the recovery of the increased insurance costs on a going-forward basis with minimal regulatory lag.

333. The Commission agrees that regulatory assets and cost trackers/riders are best reserved for extreme or special circumstances where there is substantial financial risk to the utility. Sierra has not demonstrated that recovering increased insurance costs through traditional ratemaking would result in circumstances necessitating regulatory asset treatment. The Commission understands that recovery of elements of operating cost increases between rate effective periods is preferable to Sierra; however, that is not sufficient reason for the establishment of a regulatory asset for increased insurance costs. Sierra also had the ability to request prior approval for regulatory asset treatment for these costs when it renewed its excess liability insurance coverage in August 2023 and chose not to do so.

334. Accordingly, the Commission orders that rate base be adjusted to reflect the removal of the regulatory asset created for the increased excess liability insurance costs, and that revenue requirement be adjusted to reflect the removal of any return on the unamortized regulatory asset balance and any related amortization of the excess liability insurance cost regulatory asset.

Excess Liability Insurance Premium Allocation

335. The Commission rejects allocating 50 percent of wildfire liability insurance premiums to shareholders as requested by various parties. The basis for broad state regulator decisions to allocate a portion of D&O insurance to shareholders was the nature of claims that D&O policies respond to, specifically shareholder claims related to director and officer actions resulting in economic loss to shareholders in the form of declines in stock price, which provides a direct benefit to shareholders.

336. In the case of wildfire, or other third-party damage claims arising from utility operations, Sierra acknowledges that a utility's management decisions during, or in response to, an operating incident or condition can affect the cost and availability of insurance coverage and the outcome of third-party liability claims. Sierra also acknowledges that operating, maintenance, and asset management decisions and practices made in the years or decades preceding such events can affect the cost of insurance and that there are known instances of litigation where utility decision-making with respect to shutting off power has been a premise of wildfire liability claims. (Tr. at 545-547.)

337. The Commission agrees that punitive damage awards or findings of negligence on the part of Sierra as it relates to its wildfire liability insurance policies, or on the part of any of the other named insureds covered by the corporate excess liability policies that include wildfire liability coverage, and for which Sierra is allocated a portion of the premium cost, could affect the cost and availability of such coverage and potentially raise questions with respect to the allocation of costs between customer and shareholders. In the instant docket, however, the Commission was not presented with facts or evidence related to the nature of Sierra's excess liability wildfire claims history, or the excess liability wildfire claims and litigation experience of

any of the other named insureds on the corporate excess liability policies that cover Sierra. It is on that basis, in this instant docket, that the Commission rejects the proposals to allocate 50 percent of the excess liability wildfire insurance premiums to shareholders.

338. The Commission rejects Staff proposal that Sierra allocate insurance premiums for the insurers in Sierra's excess liability coverage program that include coverage for wildfire liability using the 76-percent-Sierra to 24-percent-Nevada Power Company wildfire insurance premium allocation factor applied by Sierra to its standalone wildfire liability policies. Sierra acknowledges that the AEGIS, EIM, and Cedar Hamilton excess liability program insurers include coverage for wildfire liability. (Tr. at 541: 2-8.) The combined premiums of AEGIS, EIM, and Cedar Hamilton comprise approximately \$11.06 million, or 95 percent, of the \$11.60 million excess liability premium total. Sierra stated that wildfire risk is a very large factor contributing to the excess liability premium increase for which it is requesting recovery in this case. (Tr. at 543: 19-24.)

339. Sierra acknowledges wildfire risk differentiation in its allocation of premiums for its stand-alone wildfire liability coverages; however, Sierra does not account for wildfire risk differentiation in the allocation of the AEGIS, EIM, and Cedar Hamilton premiums between Sierra and Nevada Power. The AEGIS, EIM, and Cedar Hamilton policies and related premiums provide coverage for risks beyond wildfire liability. The Commission does not agree with allocating these premiums based solely on the wildfire premium allocation percentages used by Sierra to allocate the standalone wildfire liability policy premiums. However, in light of the annual premium of those three insurers accounting for 95 percent of the excess liability premium total, the Commission directs Sierra and Nevada Power to review alternatives for incorporating the difference in wildfire risk and exposure between Sierra and Nevada Power into the excess

liability premium allocation factors applied to the insurers in the excess liability program that includes coverage for wildfire liability (discussed here as the AEGIS, EIM, and Cedar Hamilton premiums but could include others as appropriate), with such alternatives presented to the Commission in Nevada Power's or Sierra's next general rate case filing.

340. The Commission rejects the request by BCP to open a docket to evaluate Natural Disaster Protection Plan ("NDPP") insurance coverage taking into account NDPP Tier 1, Tier 2, and Tier 3 risk ratings. It is unclear how this would be accomplished, and the Commission does not find it necessary at this time.

M. Transportation Electrification Program ("TEP") and Economic Recovery Transportation Electrification Plan ("ERTEP") Regulatory Asset

Sierra's Position

341. Sierra is requesting recovery of approximately $1.280 million of costs associated with TEP. (Ex. 205 at Schedule 1-CERT-40.) Sierra is requesting recovery of approximately $2.190 million for ERTEP in the Applications. (Ex. 205 at I-CERT-36.)

Staff's Position

342. Staff provides that Sierra has requested to recover $1,983,784 plus carrying charges of $205,896 for ERTEP (or $1,991,521 plus carrying charges of $199,563 based on the electronic papers provided at certification) and $1,279,693 for TEP, to be included in the rate base and amortized over three years. (Ex. 318 at 4.)

343. Staff states that it attempted to verify whether the costs requested for recovery in the ERTEP and TEP regulatory assets were just and reasonable, but it could not do so due to Sierra's heavily redacted level invoices being unusable. (*Id.* at 4.) Staff states that these invoices were so redacted that Staff could not ascertain whether the costs listed even pertained to ERTEP and TEP projects at all. (*Id.* at 5.) Staff states that it requested unredacted versions of the

invoices, but they were never forthcoming. (*Id.*) Staff states that it attempted to use an executable spreadsheet provided by Sierra to calculate the costs, but the spreadsheet did not contain any formulas for the calculation of certain carrying charges, and the spreadsheet does not agree with the carry calculated as shown in Sierra's certification filings. (*Id.*)

344. Staff recommends that, due to this lack of information, that the Commission disallow the recovery of legal fees in the ERTEP and TEP regulatory assets, which would result in a reduction to rate base of $18,492 and amortization expense of $6,164. (*Id.* at 6.) Staff also recommends directing Sierra to provide the correct amount for the carrying charge to be disallowed. (*Id.*)

Sierra's Rebuttal

345. Sierra states that its legal invoices were redacted due to attorney-client privilege, which Sierra maintains is still valid and protected by attorney-work product doctrine. (Ex. 254 at 5.) Sierra argues that whether these invoices are protected by any kind of privilege is irrelevant to the issue, as it has no bearing on the prudency of the costs in question. (*Id.* at 5.) Sierra states that should the Commission disallow recovery, it would result in a reduction to the TEP regulatory asset of $9,245.89 and $9,883.68 for ERTEP, and further reduce amortization expense by $3,081.96 and $3,294.56 respectively. (*Id.*) Sierra states that this reduction should include $4,000 of ADIT. (Ex. 234 at 2.)

Commission Discussion and Findings

346. The Commission agrees with Staff's recommendation to disallow recovery of legal costs associated with the TEP/ERTEP due to the significant amount of redactions in Sierra's testimony that make it impracticable for the Commission to assess the prudence of the costs incurred.

N. General Office Building ("GOB") Cafeteria Costs

Sierra's Position

347. Sierra states that the total project costs of the GOB cafeteria ("GOB Cafeteria" or "micro market") costs is $709,944.72. (Ex. 159 at Hanshew-CERT-3.)

BCP's Position

348. BCP recommends disallowing the recovery of expenses incurred by Sierra for the installation of a micro market and related improvements in Sierra's general office building, in the amount of $725,691.55. (*Id.* at 10.) BCP notes that this recovery should be disallowed as the expenditure has no direct benefits to ratepayers. (*Id.*) BCP recommends that the Commission direct Sierra to remove the entire cost of the micro market and related improvements, accumulated depreciation, depreciation expense, and deferred taxes as eligible for recovery, and to charge any further expenses related to maintaining the micro market to a non-utility account. (*Id.* at 11.)

Staff's Position

349. Staff notes that while the issue of GOB Cafeteria costs came up in Sierra's 2019 rate case, the issue was settled via a stipulation that never addressed the reasonableness of the micro market and cafeteria closure costs. (Ex. 316 at 2.) Staff notes that Sierra's GOB Cafeteria was once a self-funded operation, and any shortfalls were once covered by shareholders. (*Id.* at 3.) Staff argues that Sierra's decision to invest more than $700,000 into its new micro market added significant costs to ratepayers without any corresponding benefit. (*Id.*)

350. Staff is also concerned that Sierra is including for recovery certain machinery and equipment that was used in Sierra's now-closed cafeteria; meaning Sierra is requesting to capitalize equipment that is not used and useful. (*Id.* at 4.) Staff states that Sierra has not stated

whether it has actually retired existing equipment for the old full-service cafeteria, as Sierra continues to ask to capitalize new plant with this shuttered operation. (*Id.*) Staff warns that if the Commission were to allow the new micro market cost to be included in rates, ratepayers will be paying twice on equipment for two different cafeterias in the same location. (*Id.*)

351. Staff concludes by noting that not all costs associated with the micro market should be placed into customer rates, and Staff gives the example of a shuffleboard put in place for employee recreation. (*Id.*) Staff argues that Sierra is not entitled to earn a return on and have ratepayers cover those types of costs. (*Id.*)

352. Staff therefore recommends that the Commission reject Sierra's proposal to include the GOB Micro Market Facility project costs ($599,017) and GOB Café Interiors Improv project costs ($110, 927) from inclusion in Sierra's revenue requirement. (*Id.*at 4-5.) Staff further recommends a reduction of $0.593 million ($0.549 million, Nevada Jurisdictional) to the Sierra-E rate base, and a reduction of $0.117 million from the Sierra-G rate base. (Ex. 320 at 8, 12.)

Sierra's Rebuttal

353. Sierra states that costs for the micro market should be included for recovery, as having the micro market available in the GOB building for employee use facilitates efficient use of employee time. (Ex. 243 at 4.)

354. Sierra maintains that costs associated with the micro market should be included in rate base for recovery for Sierra-E as well, as they were approved for inclusion by the Commission in previous rate cases, namely Docket No. 19-06002. (Ex. 240 at 11.) Sierra argues that the burden of proof as to why these costs should not be included falls on BCP and Staff, and Sierra states that neither entity has demonstrated why the costs should be excluded. (*Id.* at 11-

12.) Sierra argues that without further justification from BCP and Staff, the costs for the micro market should be included for recovery for both Sierra-E and Sierra-G. (*Id.* at 12; *see also* Ex. 243 at 3.)

Commission Discussion and Findings

355. The Commission approves Sierra's inclusion of the costs of the GOB Cafeteria into the revenue requirement, less any costs associated with employee recreation.

O. Stranded IT Costs Regulatory Asset

Sierra's Position

356. Sierra is requesting that the stranded net book value of IT projects ("Stranded IT") replaced by new business transformation initiatives ($144,000 in recorded costs thus far) placed in a regulatory asset account, be included in rate base and amortized over three years. (Ex. 229 at I-CERT-31.) Sierra is requesting $144,000 in stranded net book value be included in rate base. (*Id.* at I-CERT-31.)

Staff's Position

357. Staff provides that Schedule I-CERT-31 reflects the balance of the regulatory asset Sierra established to record the stranded net book value of three software assets replaced earlier than the end of life via Sierra's long-term IT strategy initiative with carry. (Ex. 313 at 12.) Staff further provides that Sierra has booked approximately $144,000 to this schedule; broken down as $133,000 of net book value costs and approximately $11,000 in accumulated carry. (*Id.*)

358. Staff states that Sierra is attempting to implement a consolidated IT organization and improve cybersecurity, but Staff has concerns about Sierra's rationale for recording these retired-early software assets. (*Id.* at 13-14.) Staff is concerned that Sierra is interpreting a previous lack of objection and lack of Commission direction (in Docket No. 22-06014) on this

issue as permission to continue recording costs in this regulatory asset, and that there is no way for the Commission to know the actual costs associated with this asset. (*Id.* at 14.)

359. Staff states that recovery of costs in any regulatory asset account must first be explicitly approved by the Commission, and Staff is further concerned that Sierra is attempting to double recover the costs the retired software assets. (*Id.*) Staff states that Sierra recorded the NBV of the retired software assets as of the date Sierra retired those assets and applied carry from that date, but Sierra has already included the return of/return on those assets in its rate base. (*Id.*)

360. Staff argues that it is unreasonable for ratepayers to pay for the remaining net book value of a software asset that Sierra has chosen to retire early and the cost of new software assets. (*Id.* at 15.) Staff therefore recommends that the Commission deny Sierra's request to establish a regulatory asset account to record the stranded net book value of replaced software and deny recovery of approximately $144,000 of costs contained in I-CERT-31. (*Id.*) Staff further recommends that the Commission deny Sierra's proposal to continue to record the stranded NBV of replaced software assets into a regulatory asset account. (*Id.*)

Sierra's Rebuttal

361. Sierra states that its proposal to record a regulatory asset account in Docket No. 22-06014 received no objection or analysis from any of the intervenors indicating that Sierra should not record the stranded net book value as a regulatory asset, nor was there anything stated in the Commission's order directing Sierra not to do so. (Ex. 241 at 7.) Sierra states that, in the absence of any objections or guidance, it proceeded to record the stranded NBV of systems no longer in use on December 31, 2022, into a regulatory asset account. (*Id.* at 7.)

362. Sierra states that Staff failed to incorporate corresponding ADIT impacts of disallowing the entire Stranded IT NBV regulatory asset. (*Id.* at 14.) Sierra states that the regulatory asset should include $30,000 of ADIT. (Ex. 234 at 2.)

Commission Discussion and Findings

363. The Commission denies recovery of the Stranded IT and associated costs that Sierra recorded into a regulatory asset account as that proposal was not expressly approved in Sierra's prior rate case. The Commission notes that Sierra's own testimony argues that if certain items or costs are addressed in testimony but not included in Sierra's prayer for relief, those costs should not be included for recovery. (Tr. at 806: 12-25.)

364. The Commission finds that, typically, deferred costs not explicitly approved for regulatory asset treatment and for which recovery is uncertain should be recorded into a subaccount of FERC USOA Account 186. The Commission also notes that Sierra has the ability to request the creation of regulatory asset accounts for costs such as these software replacement projects.

P. Membership Dues

Sierra's Position

365. Sierra is seeking recovery of $107,000 for costs associated with membership dues paid to the American Gas Association ("AGA"). (Ex. 153 at I-CERT-24.) Sierra states that it requesting to recover 87 percent of membership dues paid to the Edison Electric Institute ("EEI"). (Ex. 321 at Attachment FC-17.) Sierra states that it has no knowledge as to how EEI determined that 13 percent of dues are deemed lobbying, and that it has no additional documents to produce. (*Id.*)

Staff's Position

366. Staff provides that Sierra is seeking recovery of membership dues paid by Sierra to the EEI and the AGA. (Ex. 321 at 4.) Staff states that it had problems ascertaining just how much money is being asked for, due to numerous errors in Sierra's filings and responses regarding these membership dues. (*Id.*) Staff states that Sierra appears to be asking to recover $227, 479 in membership dues for Sierra-E, but Staff is unclear on the correct amount allowed for recovery. (*Id.* at 4-5.) For the purposes of its testimony, Staff provides that it elected to use $224,906 (found in Sierra-E's revenue requirement filing), and when Nevada's jurisdictional share is calculated in, the EEI membership dues for Sierra-E is approximately $202,404. (*Id.* at 5.)

367. Staff's primary concern with allowing recovery for these membership dues is a lack of transparency from Sierra, in that Sierra did not provide sufficient evidence that these membership dues (even after a reduction from Sierra for lobbying) did not provide sufficient evidence that these dues are just and reasonable. (*Id.*) Staff states that Sierra is overly reliant on EEI to produce the numbers, when EEI is not a party to this proceeding. (*Id.*) Staff states that there are discrepancies between EEI's reported lobbying numbers and the reductions for lobbying claimed by Sierra-E. (*Id.* at 6.)

368. Staff is further concerned that EEI's own estimated lobbying costs are unreliable, as Staff states that EEI routinely spends more on lobbying activities than its own estimated lobbying percentages. (*Id.*) Staff also has concerns about what specific definition of "lobbying" is being used by EEI, as there are slight differences in the definition depending on the federal agency in question (IRS or FERC). (*Id.* at 9.) Staff recommends that, due to all these, Sierra's request to recover $202,404 of EEI membership dues should be denied in its entirety. (*Id.* at 10.)

369. Staff states that, similar to the EEI dues, there are errors with Sierra-G's recovery request for membership dues paid to AGA. (*Id.*) Staff states that Sierra is attempting to recover 96.6 percent (after a 3.4 percent reduction for lobbying from Sierra that relies on AGA numbers) of the AGA membership dues in Sierra-G's revenue requirement, but it is unclear on what the correct percentage or number for recovery should actually be. (*Id.* at 11.)

370. Staff states that, again, the issue with recovery of these dues is because of a lack of transparency from Sierra-G, in that it has not provided sufficient evidence that the remaining 96.6 percent of membership dues are just and reasonable for inclusion in revenue requirement. (*Id.*) Staff states that Sierra did not do its own analysis of what percentage of AGA membership dues is attributed to lobbying, and again relies on the lobbying percentage of the AGA, an organization that is not a party to this proceeding. (*Id.* at 11-12.) Staff's own review of AGA's IRS filings and budgets found no evidence to support the 3.4 percent reduction provided by AGA. (*Id.* at 12.)

371. As with the EEI dues, Staff states there is also an issue with the AGA dues recovery due to a lack of consistency in the definition of the word "lobbying." (*Id.* at 13.) Due to similar but nuanced definitions of lobbying from the IRS and FERC, it is unclear to Staff where the line is drawn between advocacy and lobbying. (*Id.* at 15.) Staff states that regardless of AGA's data or the definition of lobbying, the burden of proof is on Sierra to show why a cost included for recovery is reasonable and prudent, and Sierra has failed to demonstrate how 96.6 percent of its AGA membership dues should be included for recovery from ratepayers. (*Id.* at 16.) Staff recommends that, as such, Sierra's request to recover 96.6 percent of its AGA membership dudes should be denied in its entirety. (*Id.*)

372. Staff concludes that the Commission should deny recovery for both sets of membership dues, which results in a revenue requirement reduction of $202,404 for Sierra-E and $133,342 for Sierra-G. (*Id.* at 18.)

Sierra's Rebuttal

373. Sierra maintains that, although there were errors within the initial submission of the Master Data Requests on this topic, the membership dues for EEI and AGA are prudently incurred. (Ex. 250 at 8.) Sierra argues that membership dues for EEI help Sierra achieve its clean energy goals and regulatory operations, and that AGA dues help Sierra stay informed of industry trends, best practices, and congressional legislation that impacts natural gas operators. (*Id.* at 9.)

374. Sierra argues that any lobbying expenses incurred would amount to less than $9,000, which does not justify the complete disallowance of $202,404 to Sierra-E's rate base. (*Id.* at 10.) Sierra states that AGA does not provide an alternative amount to compare lobbying expenses to, and thus no further adjustment is needed. (*Id.*)

Commission Discussion and Findings

375. The Commission allows Sierra-E and Sierra-G to recover costs for membership dues, minus any costs that were attributed to lobbying. The Commission finds that it is appropriate to use the percentage of lobbying expense observed, rather than the estimated amount. Therefore, the Commission orders Sierra to adjust the revenue requirement to reflect Sierra's EEI membership dues excluding the lobbying activities percentages observed in 2023 of 16.4 percent for regular activities and 24.1 percent for industry issues, instead of the estimated 13 percent and 20 percent used to reduce those same activities in its applications.

Q. IT Disallowance

Sierra's Position

376. Sierra previously identified $8,949,296 in additional infrastructure and operations investments but changed its position in its certification testimony to now request for recovery $10,273,461. (Ex. 168 at 2-3.) Sierra states that the reason for this increase is due to the purchase of certain hardware upgrades, along with the fact that intercompany billing for BHE affiliate programs was delayed and certain costs were therefore not included in preliminary estimates. (*Id.* at 3.)

Staff's Position

377. Staff states that there are inconsistencies with the dollar amounts sought for recovery by Sierra regarding its IT project costs that were added to Plant-In-Service since the close of the certification period. (Ex. 312 at 1.) Staff provides that Sierra is seeking recovery of $27,575,712 for IT infrastructure projects for Sierra-E, with the total cost of all plant additions through the test period being $17,302,251 with the total cost estimate through the certification period is $8,949,296. (*Id.* at 2.) However, Staff states that the actual total cost in the certification period increased to $10,273,461 with a cost variance of $1,324,165 from the original certification estimates. (*Id.*)

378. Staff further provides that, for Sierra-G, Sierra is seeking recovery of $136,685,293 for all plant, with the total cost all plant additions through the test period being $130,386,804 and the total cost estimate in the certification period was $5,533,609. (*Id.* at 3.) However, Staff states that the actual total cost in the certification period increased to $6,298,488 with a cost variance of $764,879 from the original certification estimates. (*Id.*)

379. Staff's first concern with these projects is that they were presented for recovery for the first time in the certification filing, which forced Staff to review a brand-new project at the end of the review process. (*Id.*) Staff argues that Sierra should have filed an amendment to its original filing as soon as possible, rather than waiting for the certification period. (*Id.*)

380. Staff's second concern is related to the first, in that Sierra knew about the existence of these projects at the time of the filing of the general rate case, but nevertheless neglected to include them as estimates that could be corrected in the certification filing. (*Id.* at 4.) Staff argues that the Commission has, in previous dockets, rejected requests for recovery that were not included in the original filings but still known to the utility at the time of the original filing. (*Id.* at 4-5.)

381. Staff therefore recommends that the Commission reject Sierra's $883,662 request for recovery of IT projects. (*Id.* at 5.) Staff further recommends disallowing approximately $0.676 million ($0.626 million, Nevada jurisdictional) from the Sierra-E rate base and disallowing $63,000 (100 percent Nevada jurisdictional) from Sierra-G's rate base. (Ex. 320 at 9, 13.)

Sierra's Rebuttal

382. Sierra argues that because none of the projects included were over $1 million, they were not identified in the original application. (Ex. 241 at 3-4.) Sierra argues that it provided documentation to Staff demonstrating that these projects are prudent and reasonable. (*Id.* at 4.) Sierra goes on to argue that all projects began during the test period but were not concluded with all costs received until the certification period. (*Id.* at 5.) Sierra does not oppose deferral of these costs until the next general rate case should the Commission disagree with Sierra's position. (*Id.*)

Commission Discussion and Findings

383. The Commission denies recovery of the costs associated with the IT projects included for recovery during the certification period, identified by Staff. (Ex. 312 at Attachment YA-1.) Sierra was aware of the projects during the test period and failed to include them in the certification period estimate. The Commission finds that adding projects during the certification period reduces the prudency review period for Staff and other parties. In its next general rate case, Sierra may request that these projects be included in Plant-In-Service, net of any accumulated depreciation.

384. As a compliance item, Sierra must remove these costs from the list of projects contained in Ex. 312 at Attachment YA-1.

R. Short-Term Incentive Pay ("STIP")

Sierra's Position

385. Sierra provides that all non-represented employees are eligible for STIP. (Ex. 193 at 27.) Sierra states that STIP payments are based on corporate goals and vary from year-to-year depending upon the achievement of company-wide goals, and a combination of the achievement of business unit, or departmental goals, and the individual employee's performance. (*Id.* at 29.) Sierra states that its company-wide goals are aligned with the following six core principles: Customer Service, Employee Commitment, Environmental Respect, Regulatory Integrity, Operational Excellence, and Financial Strength. (*Id.* at 31.) Sierra states that STIP payments were only paid to eligible employees who are deemed to be meeting performance expectations based on assessment by their leader. (*Id.* at 28.)

386. Sierra provides that the annual corporate scorecard is one tool used to determine annual incentive funding with adjustments made to reflect performance results that are not

captured within the scorecard or not measured based on the established targets. (*Id.* at 36.) Sierra states that the scorecard key performance indicators and targets are generally established as stretch targets to keep the organization focused on what it has been able to achieve historically to help drive continuous improvement across the six core principles. (*Id.*) Sierra states that, in 2023, the scorecard results delivered a mathematical outcome of 56.8 percent. (Ex. 195 at 3.) However, Sierra explains that the annual incentive payout was awarded at 85 percent, which is higher than the mathematical result in recognition of several performance achievements. (*Id.* at 6.)

387. Sierra provides that its calculated annual revenue requirement includes $2.91 million for STIP expense, paid out at the 85 percent level minus the Financial Strength metric. (Ex. 230 at I-CERT-17; Ex. 195 at 11.)

BCP's Position

388. BCP states that neither Nevada Power nor Sierra have been adhering to their own qualifications for STIP payouts for many years. (Ex. 406 at 3.) BCP argues that scorecard targets are compromised annually, and that the scorecard was just one tool for measuring employee performance, with other adjustments being made that aren't captured on the scorecard. (*Id.* at 4-5.) BCP argues that the achievements on the scorecard can only be justified in hindsight, and further, there is no documentation or consistency regarding on how these other adjustments outside the scorecard are made. (*Id.* at 4.) In addition, BCP asserts that it appears from the historical information that Sierra's employee compensation is at minimal risk since the actual payout is always above what has been achieved. (*Id.*) BCP maintains that these variable costs are consistently incurred regardless of Sierra achieving the desired results. (*Id.* at 5.) BCP

highlights that this has been a recurring issue in general rate case proceedings for STIP payouts. (*Id.*)

389. BCP states that the STIP payout for 2023 was set at 85 percent out of 100 percent. (*Id.* at 6.) BCP states that Sierra did not achieve the year-end result of 85 percent out of 100 percent. (*Id.*) BCP states that, in reality, Sierra achieved 56.82 percent out of 100 percent. (*Id.*) BCP asserts that Sierra decided to undeservedly payout at 85 percent and that Sierra is seeking the full recovery of the 85 percent payout from ratepayers. (*Id.*)

390. BCP argues that Sierra provided excuses to justify the STIP payout that deviates from actual scorecard results. (*Id.* at 8.) First, BCP states Sierra continues to define the key performance indicators (metrics) as goals, when in reality these metrics should be met in the normal course of business. (*Id.*) Secondly, BCP states that Sierra claims the scorecard is just one tool and that other adjustments can be made which are not captured on the scorecard. (*Id.*) BCP highlights that these adjustments are not documented anywhere, appear arbitrary, and are at the discretion of Sierra's and BHE's CEO. (*Id.* at 4.)

391. BCP objects to Sierra's proposed 85 percent STIP payout because employees did not earn the payout per the corporate scorecard. (*Id.* at 7-8.) BCP reiterates its argument that any STIP recovery from ratepayers should not be expected when it is in hindsight, inconsistent, non-transparent, undocumented, and partially justified by a forecasted score. (*Id.*at 8.)

392. BCP recommends disallowing the entire STIP payment given that there is no transparent and consistent methodology in place, but it would also accept BHE shareholders absorbing the difference between the scorecard and the payout (*Id.* at 9.) BCP would adjust Sierra's proposed payout from 85 percent to 51.79 percent, which factors in Sierra's weighting of scores associated with outperformance (*Id.* at 10.) BCP argues that consistent overpaying for

non-earned achievements and/or the inequity in the weight assigned to key performance indicators leads to unjust and unreasonable results. (*Id.*)

393. BCP argues that the STIP payout reduction (to both represented and non-represented employees) impact on revenue requirement for Sierra-E is a decrease of $1.004 million and $152,000 for Sierra-G. (*Id.* at 12, with correction.)

Staff's Position

394. Staff provides that the corporate scorecard delivered a mathematical outcome of 56.8 percent. (Ex. 310 at 15.) Staff further provides that Sierra stated that the annual incentive payout was awarded at 85 percent, which was higher than the mathematical result in recognition of several performance achievements. (*Id.*)

395. Staff points out that Sierra has consistently given a STIP payout greater than the earned results of the STIP scorecard. (*Id.*) Staff states that this practice is problematic because Sierra has created an employee expectation that regardless of their actual effort and the resulting corporate scorecard achievement, the STIP will be funded at or near 100 percent. (*Id.* at 22.) Staff argues that it is impossible to mathematically discern how much of the STIP results are tied to the scorecard and how much are tired to after-the-fact performance achievements. (*Id.*) Staff asserts that asking for 85 percent of STIP funding to be recovered in rates creates a situation where ratepayers are being asked to pay for STIP costs that do not have corresponding, measurable ratepayer benefits. (*Id.*)

396. Further, Staff provides that it appears that the overall STIP payout amount is discretionary. (*Id.* at 16.) Staff states that Sierra states that the corporate scorecard is one tool used to determine annual incentive funding with adjustments made to reflect performance results that are not captured mathematically within the scorecard or not measured based on the

established targets. (*Id.*) Staff provides that when asked to elaborate on how the final STIP payout was determined, Sierra states that the STIP payout amount is determined based on the recommendation of Sierra's President and CEO and subject to approval by the BHE President and CEO, and that the percentage is determined based on their assessment of business performance achievements. (*Id.*) Staff states that Sierra adds that there is no mathematical formula for consideration of the performance achievements that funded the STIP at 85 percent. (*Id.* at 22.)

397. Staff argues that employees earning a STIP that is at or near 100 percent negates STIP's purpose of being variable, at-risk compensation that has to be re-earned every year, and essentially turns STIP into a second form of base pay. (*Id.*)

398. Staff recommends that the Commission disallow 100 percent of the STIP payout amount that was awarded to non-officer and officer employees' Safety Bonus (*Id.* at 23.) Staff recommends in the alternative that the Commission split the STIP costs, 50/50, between ratepayers and Sierra. (*Id.* at 24.) Staff makes this alternative recommendation based solely on the idea that actions achieved by employees on the scorecard could arguably have some benefit to ratepayers, with some amount of the cost being recovered in rates. (*Id.* at 23.)

399. Staff states that disallowing STIP recovery in its entirety would result in reductions to Sierra's revenue requirement of $3.306 million for Sierra-E and $0.509 million for Sierra-G. (Ex. 317 at 3.)

Sierra's Rebuttal

400. Sierra disagrees with Staff and BCP's assertion that performance achievements for employees are identified after the fact or in hindsight to justify a higher STIP payout. (Ex. 249 at 3.) Sierra states that its President and CEO only have the authority to recommend the

STIP funding amount and do not have the authority to independently decide what the STIP payout is. (*Id.*) Staff states that BHE regularly reviews Key Performance Indicators ("KPIs") as well as performance results to ensure Sierra accurately measure and reports performance outcomes. (*Id.* at 3-4). Sierra also disagrees with assertions that employees are unaware of these KPIs, as it states that employees are regularly informed via meetings and employee forums of Sierra's priorities on an annual and longer-term basis. (*Id.* at 4.)

401. Sierra disagrees with Staff's assertion that if all KPIs were met, then the total STIP payout would be at 100 percent, and that if an employee overachieved performance for all KPIs, the payout would be at 125 percent. (*Id.* at 5.) Sierra disagrees because the corporate scorecard result does not define the level of funding for STIP. (*Id.*) Sierra states that the annual corporate scorecard is a component of the funding recommendation, subject to approval by the BHE President and CEO. (*Id.* at 6.) Sierra re-iterates that the annual corporate scorecard is not the same thing as the STIP scorecard, rather it is a tool used to track specific corporate KPIs, which is one input to determine funding for the STIP. (*Id.*)

402. Sierra also disagrees that there is employee expectation of STIP being paid at or near 100 percent, which removes variability and turns the STIP into a second form of base pay. (*Id.* at 6.) Sierra provides that there are two elements of the STIP payout. (*Id.*) Sierra states that the first is corporate performance results. (*Id.*) Sierra explains that Sierra's outcomes and performance results are used to determine the funded percentage at the corporate level. (*Id.* at 7.) Sierra states that it is a comprehensive view of overall organizational performance. (*Id.*) Sierra states that the second element is an employee's individual performance results, which are assessed annually by a direct supervisor. (*Id.*) Sierra states that a review of the STIP awards paid in 2023 shows that a majority (66.6 percent) of employees received an incentive award amount in 2022

that fell below the funded amount of 85 percent, less than 10 percent received an award at the funded amount, and approximately 25 percent received an award above the funded amount. (*Id.*) Sierra explains that its focus on varying incentive pay based on individual performance results ensures that employees do not view the STIP as a second form of base pay. (*Id.*)

403. Sierra disagrees with BCP's calculations due to the fact that an error was made by BCP when it included the STIP recovery amount that should remain instead of the amount to be removed. (Ex. 250 at 22-23.) Sierra states that the correct reduction to expense for BCP's adjustment would be $1.004 million for Sierra-E and $0.152 million for Sierra-G. (*Id.* at 23.)

Commission Discussion and Findings

404. The Commission adjusts Sierra's certification revenue requirement by disallowing the STIP payout amount that was awarded to employees above the 56.8 percent that was earned on the fourth-quarter corporate scorecard. Employees earned a score of 56.8 percent for 2023, as shown on the fourth-quarter corporate scorecard; however, the annual incentive payout was awarded at 85 percent. The Commission notes that the 56.8-percent actual achievement result for 2023, and approved for recovery here, reflects a zero-percent achievement result for financial performance metrics, which have been found by the Commission in past dockets to primarily benefit shareholders rather than customers. The Commission again finds that the financial performance metrics primarily benefit shareholders rather than customers. However, as the financial performance metrics STIP payout amount was zero percent based on results, no adjustment is required in this case to remove STIP compensation related to financial performance metrics from the amount to be recovered from customers.

405. The Commission agrees with Sierra and Staff that Sierra's base pay levels for represented, non-officer and officer employee groups is reasonable and consistent with industry

standards. However, the Commission does not find Sierra's justification for requesting STIP recovery from customers in excess of the year-end STIP scorecard achievement level compelling or reasonable. Both Staff and BCP provide testimony and related data indicating that the staffing concerns raised by the Commission in its approval of recovery of STIP amounts in excess of amounts earned based on STIP scorecard results in Nevada Power's general rate case in Docket No. 23-06007 have been resolved, and the Commission agrees. The Commission also agrees with Staff and BCP that the additional justification and achievements cited by Sierra for funding STIP payouts above the amount earned by employees based on the year-end STIP scorecard results represent core, normal-course-of-business, base-level performance.

406. The Commission finds that it is Sierra's prerogative to pay its employees STIP amounts above what was achieved on the corporate scorecard; however, in doing so, Sierra creates an expectation from employees that STIP will be funded at 100 percent, regardless of the corporate scorecard achievement. Sierra's STIP is variable, at-risk performance pay that must be re-earned every year. Sierra is responsible for creating STIP goals with clear linkage and line of sight to employees and the objectives to which their actions and efforts are directed. A performance management and incentive compensation process that communicates objectives to employees, measures the results, and then revises or replaces the objectives during the year in response to below-target scorecard results is not a reasonable construct for cost-recovery from customers.

407. The Commission finds that in approving the recovery of STIP incentive compensation costs from customers, it is important that the employee actions being rewarded are tied to ratepayer benefits. Allowing Sierra to recover STIP employee compensation awards from customers at a higher percentage than what was earned by employees based on actual STIP

scorecard achievement levels results in customers paying for bonuses that do not provide them with direct, commensurate benefits, which the Commission finds to be unjust and unreasonable. Accordingly, the Commission adjusts Sierra's requested revenue requirement to reflect the 56.8-percent STIP funding level discussed above.

S. Ampere Road Expansion Project

Sierra's Position

408. Sierra states the total project cost of the Ampere Road Expansion Project is $1,754,516.28 (Ex. 159 at Hanshew-Certification-3.)

Staff's Position

409. Staff states that Sierra asked for recovery for the expansion of Ampere Road near it's Ohm Operations Center previously in Sierra's 2019 general rate case, and the issue was eventually settled via a stipulation that did not address the reasonableness of the Ampere Road expansion costs. (Ex. 315 at 17.) Staff states that Sierra has brought this forward for inclusion in Sierra-G's revenue requirement. (*Id.* at 17.)

410. Staff is concerned about the inclusion of the Ampere Road expansion costs because Sierra did not conduct a fair bidding process with contractors. (*Id.* at 18.) Staff states that two contractors bid on the project, A&K Earthmovers ("A&K") and Q&D Construction ("Q&D"). (*Id.*) Staff states that A&K made the lower of the two bids, by a difference of $230,355. (*Id.*) Staff states however that Sierra rejected A&K's bid over a missing section of paperwork, opting to simply go with the more expensive Q&D bid. (*Id.*) Staff argues that Sierra should have reached out to A&K over this minor issue in an effort to save ratepayers $230,355, but Sierra just disqualified A&K anyway, despite working with A&K many times before. (*Id.*)

411. Staff has doubts that the expansion of Ampere Road should be included for recovery, as it was not immediately needed for the safe and reliable operation of the Ohm Center. (*Id.* at 19.) Staff is however not recommending the Commission disallow the entirety of the costs however, just the $230,355 described above. (*Id.*) Staff states that this should be disallowed as NV Energy/Sierra failed to make reasonable efforts to accept the lowest bid for the project. (*Id.*)

412. Staff recommends a disallowance of $0.192 million ($0.178 million Nevada jurisdictional) from the Sierra-E rate base and $0.038 million (100 percent Nevada jurisdictional) from the Sierra-G rate base for this project. (Ex. 320 at 4, 10.)

Sierra's Rebuttal

413. Sierra stands by its bidding process and argues that it communicated the requirements for a qualified proposal to A&K, and when A&K did not provide the required information, its bid was disqualified. (Ex. 243 at 2.) Sierra states that it did not re-bid the project because it likely would have resulted in the same limited response and a delay of the project, which would in turn impact the projected cost. (*Id.* at 3.)

Commission Discussion and Findings

414. The Commission finds it appropriate to exclude from Sierra's recovery the difference between its accepted bid from Q&D and the lowest bid from A&K, in the amount of $230,355.

415. The Commission finds that no evidence was provided to substantiate the claim made in Sierra's testimony that it tried to help A&K remedy its bid deficiencies. The Commission notes that Sierra has an extensive work history with A&K, so to not allow A&K to

remedy its bid package for this project was unreasonable. The Commission finds that paying 27 percent more, effectively as a premium, was not prudent.

T. Pinehaven Fire Litigation Regulatory Asset

Sierra's Position

416. Sierra states that it is no longer seeking recovery of costs associated with the Pinehaven fire litigation, as another claim associated with the fire has been filed. (Ex. 147 at 18.) Sierra will instead continue to defer these litigation costs until all actions have ceased, at which time Sierra will bring the costs forward for recovery. (*Id.* at 18.)

Staff's Position

417. Staff states that the Modified Final Order in Docket No. 22-06014 did not authorize Sierra to establish a regulatory asset account to track the Pinehaven fire litigation and settlement costs. (Ex. 313 at 23.) Staff states that there was litigation between Sierra and its insurance providers over responsibility for this fire, which led to Sierra seeking recovery of approximately $212,000 in litigation costs in Docket No. 22-06014. (*Id.* at 24.) Staff states that the Commission did not approve Sierra's request to recover the Pinehaven litigation costs in Docket No. 22-06014, but instead deferred recovery as there was pending litigation in the matter. (*Id.*) Staff notes that the Commission's order did not explicitly direct Sierra to create a regulatory asset for these litigation costs. (*Id.*)

418. Staff notes that Sierra is not seeking recovery for Pinehaven fire litigation expenses in the instant docket, as litigation is still pending, and Sierra is deferring until the litigation ceases. (*Id.* at 25.) However, Staff is concerned that Sierra is still tracking the costs of this litigation in a regulatory asset account. (*Id.*) Staff states that Sierra is doing this because it has no other way of tracking the charges than to create a regulatory asset. (*Id.*)

419. Staff argues, however, that the Commission's Modified Final Order in Docket No. 22-06014 did not create a regulatory asset for the Pinehaven fire litigation costs. (*Id.* at 26.) Staff notes primarily that the Modified Final Order only applies to the approximately $212,000 sought for recovery in Docket No. 22-06014, but also that the Commission accepted Staff's recommendation in that docket and denied Sierra's request. (*Id.*) Staff again notes that its recommendation in Docket No. 22-06014 did not include authorization of a regulatory asset account. (*Id.*) Lastly, Staff notes that a regulatory asset account is generally used to track deferred expenses that have a likelihood of recovery, and there is no evidence in this matter to determine whether recovery is likely, given the contentious litigation surrounding the fire. (*Id.*)

420. Staff concludes by recommending that the Commission find its Modified Final Order in Docket No. 22-06014 did not authorize Sierra to establish a regulatory asset account for the Pinehaven fire litigation costs, and further recommends that the Commission deny Sierra's proposal to continue recording these costs into a regulatory asset account. (*Id.*)

Sierra's Rebuttal

421. Sierra argues that the Modified Final Order in Docket No. 22-06014 did indeed provide Sierra with ample justification to use a regulatory asset account for deferring Pinehaven costs. (Ex. 252 at 29.) Sierra notes that the order did not directly state to use a regulatory asset for these costs, nor did it directly state to use a deferred debit. (*Id.*) Sierra states that either argument is a reasonable approach but reiterates that Pinehaven costs are not being sought for recovery in this case. (*Id.*)

Commission Discussion and Findings

422. The Commission finds that neither the Modified Final Order nor Sierra's testimony in Docket No. 22-06014 specifies whether the deferred expenses should have been

recorded as a regulatory asset (FERC Account 182.3), or as deferred debits in FERC Account 186.

423. Costs permitted for inclusion in a regulatory asset account include those that are probable to be included in a different period for purposes of developing rates that the utility is authorized to charge. The Commission finds that the recoverability of costs for, and that are subject to, ongoing litigation cannot be considered "probable to be included in a different time period." (18 Code of Federal Regulations § 367.1823.) Accordingly, the Commission accepts Staff's recommendation to reclassify costs associated with the Pinehaven fire litigation, minus carrying charges, as deferred debits, rather than as a regulatory asset.

U. New Year's Eve Storm

Staff's Position

424. During Staff's review of the test period O&M expenses, it found a larger variation in distribution plant O&M over the 3 years provided. (Ex. 314 at 14.) Staff states that its subsequent investigation found an increase of about $9 million in the 2022-2023 time period, which eventually led it to finding that the source of this increase was from the New Year's Eve Storm on December 31, 2022. (*Id.* at 14-15.)

425. Staff disagrees that Sierra should be allowed to collect annually for a once in a 43-year storm, as such an occurrence is not annual even by Sierra's own forecasts. (*Id.* at 15.) Staff further disagrees with recovery of costs due to the storm because Sierra is already investing millions of dollars in system hardening pursuant to its NDPP. (*Id.* at 15.) Staff argues that allowing Sierra to recover these storm costs, rate payers will be paying for both system hardening and storm repairs at the same time, which undercuts the benefit to ratepayers of NDPP system hardening. (*Id.*)

426. Staff states that instead of recommending no recovery, the recovery should instead be reduced proportionate to the risk of such a storm occurring. (*Id.* at 16.) As such, Staff recommends that the Commission disallow 42/43 (or 97.6 percent) of the cost related to the New Year's Eve storm, and only allow recovery of 1/43 (or 2.3 percent) of the approximately $5 million in costs requested for recovery by Sierra. (*Id.*)

427. Staff recommends that the Commission remove approximately $5.264 million of distribution plant O&M cost from the 2022 New Year's Eve Storm. (Ex. 320 at 7.)

Sierra's Rebuttal

428. Sierra states that these types of storms are happening more frequently now, with Sierra experiencing a historic storm over Leap Day weekend of 2024, and a hurricane in its service territory in August 2023, both of which caused significant damages and outages that required additional resources and costs to restore service. (Ex. 252 at 23.)

429. Sierra states that because these storms are happening more frequently, Staff's recommendation to allow only 1/43 of recovery is an oversimplification of the circumstances and a potential deviation from cost-based rates. (*Id.* at 23.) Sierra recommends that it be allowed to recover $5.1 million over the next three years, or $1.8 million in revenue requirement. (*Id.*) Sierra maintains that these costs were prudently incurred during the test period, and that the ESM will capture any potential overcollection. (*Id.*) Sierra recommends no adjustment be made to its request to recover $5.1 million over the next three years. (*Id.*)

Commission Discussion and Findings

430. The Commission finds it appropriate for Sierra to recover costs associated with the New Year's Eve storm, amortized over a three-year period. Staff correctly identified that this was an anomalous event; however, the Commission concurs with Sierra that allowing only 1/43

recovery is unreasonable. Amortizing the costs over a three-year period recognizes the unusual nature of the event while also recognizing that the costs were prudently incurred. The Commission acknowledges Sierra's urgent response to service interruptions, which may be more challenging during inclement weather. Further, the Commission urges Sierra to more closely monitor and maintain its assets to reduce the frequency and duration of service interruptions, especially if Sierra expects storm events to increase in frequency and ferocity in the near future.

431. The Commission recognizes costs may be difficult to track for record-keeping purposes during high-volume events such as inclement weather. The Commission also recognizes that it is imperative that Sierra maintains its normal business practices throughout weather events as much as possible. The Commission finds that permitting Sierra to maintain those business practices will allow Sierra employees to better identify asset maintenance and service interruption data as well as subsequently allow for robust prudency reviews by the intervening parties.

V. Transmission O&M

Staff's Position

432. Staff states that it investigated a slight variation over a three-year period in O&M expenses, and it found that some of the cost increases were due to light detection and ranging, surveys of existing transmission lines, and vegetation management. (Ex. 314 at 17.) Staff states that it is appropriate to normalize these expenses over a longer period of time (three years) so that ratepayers are not overpaying for the next several years based on an artificially elevated test period while still allowing Sierra fair opportunity to recover costs. (*Id.* at 17.)

433. Staff recommends that the Commission order Sierra to normalize its Transmission O&M expenses using the average annual expenses from 2020 through 2023. (*Id.*) Staff further

recommends a decrease in Sierra-E's revenue requirement of $0.487 million (100 percent Nevada jurisdictional.) (Ex. 320 at 7.)

Sierra's Rebuttal

434. Sierra states that Staff has not sufficiently justified its request for normalization. (Ex. 252 at 26.) Sierra states that Staff did no analysis to determine whether costs (such as those associated with light detection and ranging surveys, vegetation management, and tree trimming) are expected to decrease in the coming years. (*Id.* at 26.) Sierra states there is no reason to expect such costs to decrease in the coming years. (*Id.* at 26-27.) Sierra states that some of these costs have increased, while others have decreased. (*Id.* at 27.) Sierra argues that Staff is more concerned about the amount of money spent here, rather than arguing the imprudence of the costs. (*Id.*)

Commission Discussion and Findings

435. The Commission rejects Staff's recommendation to normalize costs. Sierra has adequately identified its costs associated with transmission and maintenance. Staff characterized the issue as a slight variation. A slight variation, whether higher or lower, is reasonable when taking material and labor price variations in recent years, including inflation. The Commission therefore declines to make an adjustment at this time.

W. Budget ID GD2243_05R

Sierra's Position

436. Sierra states that the total cost of service replacements is $230,002.79, of which $20,336 is being removed. (Ex. 159 at Hanshew-CERT-2.)

Staff's Position

437. Staff provides that a portion of the order in Docket No. 24-02007 contained a stipulation with a directive stating that Sierra was not to include for recovery costs associated with Sierra's violations of Nevada's One Call Law and 49 CFR 192 from ratepayers in Sierra's next general rate case. (Ex. 311 at 13.)

438. Staff argues that Sierra has failed to keep track of the costs associated with the damage described in Docket No. 24-02007 and has included a portion of those costs in this current general rate case. (Id. at 14.)

439. Staff states that Sierra has violated Commission orders similar to this one in the past, but Staff notes that Sierra removed the majority of the costs associated with the dig and labor from inclusion in its general rate case filings. (*Id.* at 15-16.)

440. Staff recommends disallowing approximately $20,336 from Budget ID GD2797_22D from Sierra-G's revenue requirement model (the remaining costs not already taken out by Sierra), and that the removal of such costs should not be brought forward in a subsequent general rate case. (Ex. 311 at 19.) Staff notes that, while this number is small when compared to other Staff adjustments, permitting recovery on such costs then gives Sierra a strategy by which it can potentially undermine a Commission order and remove costs from unrecoverable work orders and place them within capital projects. (*Id.* at 18.)

Sierra's Rebuttal

441. Sierra states that it will remove $20,336 of labor and overhead costs that were accidentally allocated to the non-new business service blanket work order as a part of its compliance filing. (Ex. 240 at 12, *see also* Ex. 244 at 21.)

Commission Discussion and Findings

442. The Commission accepts the parties agreement to remove $20,336 in costs associated with Budget ID GD2243_05R, as they were recorded improperly. Sierra may not seek those costs in a subsequent rate case filing. The Commission urges Sierra to review its project tracking processes or systems to determine whether regulatory or compliance checks are adequately represented and easily identified by users.

X. Unprotected Excess Accumulated Deferred Income Taxes ("ADIT")

Sierra's Position

443. Sierra-E is requesting a 3-year amortization period for the Period 3 balance Unprotected Excess ADIT balance as of February 29, 2024, of $1.801 million in I-CERT-41 with an annual amortization amount of $0.600 million. (Ex. 197 at 8; Ex. 199 I-CERT-41.) Sierra is requesting to place $3.974 million in total in Unprotected Excess ADIT into the rate base for Sierra-E, with a $0.083 million placed into annual amortization in total. (Ex. 197 at 8; Ex. 199 I-CERT-41). Sierra-G is requesting to place $4.672 million in total Unprotected Excess ADIT into the rate base for Sierra-G, with a ($0.308) million annual amortization. Sierra-G is also requesting to place ($21.603) million in Protected Excess ADIT (ARAM) into rate base. (Ex.198 at 9; Ex. 229 at I-CERT-27).

Staff's Position

444. Staff states that errors contained in Sierra's Schedule I-Cert-21 resulted in an overstatement of the rate base for Unprotected Excess ADIT. (Ex. 321 at 37.) Staff states that the correct calculations result in a rate base decrease of approximately $3.415 million from $7.309 million for Sierra-E to $3.894 million, and a rate base decrease of approximately $0.213 million from $0.501 million to $0.288 million for Sierra-G. (*Id.* at 37-38.)

445. Staff states that the certification to Unprotected ADIT Excess was erroneously included in the rate base twice, once in Schedule H-Cert-21 and again in H-Cert-41, which also resulted in an overstatement of the rate base. (*Id.* at 38.) From the current Schedule I-Cert-21 to the revised Schedule I-Cert-21, Sierra-E's rate base was decreased by approximately $5.087 million, with a reduction of $0.316 million for Sierra-G's rate base. (*Id.*) Staff notes that Sierra is not including these corrections in its current revenue requirement, but they will be incorporated into the compliance filing to be submitted after the Commission issues an order in this matter. (*Id.*)

446. Staff is concerned about the errors that still exist in the current version of Schedule I-CERT-21, as those errors are estimated to result in a reduction of $0.481 million to Sierra-E's revenue requirement and a reduction of $31,000 to Sierra-G's revenue requirement. (*Id.* at 39.) Staff states that Sierra's delay in filing an errata on this issue unfairly prevents Staff, intervenors, and the Commission from reviewing the impact of the errors on Sierra-E's requested revenue requirement and gaining a better understanding of the full scope of this case. (*Id.*)

447. Staff therefore recommends that the Commission accept Staff's adjustments to Sierra's errors contained in the current Schedule I-CERT-21, which results in a rate base reduction of approximately $5.087 million for Sierra-E and a rate base reduction of $0.316 million for Sierra-G. (*Id.*)

448. Staff has similar concerns regarding Schedule I-CERT-41, as it contains errors that have not been corrected at the time of certification. (*Id.* at 40.) Staff states that these errors resulted in a revenue requirement increase of approximately $3.043 million, with the same increase to the rate base. (*Id.*) Staff states that Sierra's delay in filing an errata and instead waiting until certification to correct these errors unfairly prevents Staff, intervenors, and the

Commission from reviewing the impact of these errors on Sierra-E's revenue requirement. (*Id.* at 41.)

449. Staff therefore recommends that the Commission accept adjustments made to Sierra's errors in Schedule I-CERT-41, which results in a revenue requirement increase of approximately $3.043 million and a rate base increase of approximately $3.043 million for Sierra-E. (*Id.*)

450. Staff agrees with the amounts provided by Sierra in its rebuttal, but notes there were additional adjustments necessary for ADIT. (Tr. at 523: 19-23.)

Sierra's Rebuttal

451. Sierra agrees with Staff's recommendation to reduce its rate base by $5.087 million for Sierra-E and a reduction of $0.316 million for Sierra-G due to errors in I-CER-21 (Ex. 250 at 10.) Sierra also agrees with Staff's recommendation to increase its rate base and revenue requirement by $3.043 million in Sierra-E due to errors in I-CERT-41. (*Id.* at 10.) Staff notes however that these adjustments also result in an adjustment to ADIT, in the amounts of $ and $1.068 million and ($639,000) for Sierra-E (*see* Ex. 250 at Naughton Rebuttal-2) and $66,000 for Sierra-G (*see* Ex. 250 at Naughton Rebuttal-2.)

Commission Discussion and Findings

452. The Commission accepts the parties agreement to reduce Sierra's rate base by $4.019 million (net of ADIT) for Sierra-E and $0.250 million (net of ADIT for Sierra-G due to errors in I-CERT-21), and the Commission also accepts the parties agreement to increase Sierra-E's rate base by $2.404 million (net of ADIT) due to errors in I-CERT-41. As a compliance item, Sierra shall file the schedules supporting these adjustments in electronic executable form with all links and equations intact.

453. Additionally, the Commission approves the requested three-year amortization of Sierra-E's Unprotected Excess ADIT as corrected. The Commission notes that no party objected to the amortization period.

Y. Second Source Project Allowance for Funds Used During Construction ("AFUDC")

Sierra's Position

454. Sierra provides that the south Reno second source project is a new, 17-mile, large capacity gas pipeline constructed between the Tracy Generating Station and south Reno. (Ex. 179 at 7.) Sierra states that this project connects with the existing Rainbow Bend system, as well converts the Rainbow Bend propane distribution system to natural gas. (*Id.* at 7.) Sierra states that the project is necessary to serve growing gas demand in the area, and its benefits customers by strengthening delivery capabilities to south Reno, mitigating the largest N-1 contingency within the gas distribution network, and by improving area distribution network reliability and facilitating pressure reduction. (*Id.*) Sierra states that the major portions of the project were energized and in service prior to the end of the certification period, and it is not seeking recovery for portions of the project not yet completed. (*Id.* at 8.)

455. Sierra states that the total plant addition cost for this project is $44,808,897, including AFUDC. (*Id.*)

Staff's Position

456. Staff states that the issue on this subject is the correct time for Sierra to stop accruing AFUDC on certain phases of the south Reno second source facilities constructed to date. (Ex. 315 at 3.) Staff states that Sierra represented that the pipeline in question was complete and capable of flowing gas as of December 2022. (*Id.*) Staff states that Sierra was however unable to secure a plumbing contractor to perform the needed appliance conversions so

that the Rainbow Bend pipeline could flow natural gas instead of propane. (*Id.* at 4.) Staff states that it was the sole responsibility of Sierra-G to secure a plumbing contractor for this project, and therefore it is not just or reasonable to grant Sierra-G's request to include excess AFUDC in its rates. (*Id.*) Staff argues that Phase I and Phase II of these projects, which were both fully complete and capable of operation, just sat there accruing AFUDC while other separate parts of the project were still under construction. (*Id.*)

457. Staff argues that the AFUDC should have stopped accruing on these projects as of December 2022, after which Staff totaled the amounts of monthly AFUDC recorded by Sierra-G, which resulted in Staff's recommended disallowance of $2,238,624. (*Id.* at 5.) Staff recommends that the Commission remove $2,239,624 of AFUDC from the Sierra-G rate base. (Ex. 320 at 12.)

458. Staff states that Sierra constructed a 17-mile, 16-inch diameter, 320 psi gas pipeline from near the Tracy station east of Reno to a location adjacent to south Reno, which Staff states would have significant benefit to ratepayers in the Sparks and south Reno areas of Northern Nevada, in that it would create a second source for gas supply should the main source be disrupted. (Ex. 315 at 6-7.) Staff notes however that several additional projects must be completed by Sierra before these benefits are fully realized for ratepayers. (*Id.* at 6-7.)

459. Staff provides that Sierra-G is requesting recovery of ten Project I.D.s that together comprise the south Reno second source project, and Staff breaks these projects down into four different groups. (*Id.* at 10-11.) Staff states that half the projects in Group 1 are complete, and it therefore recommends putting 50 percent of Group 1 costs, approximately $619,810, into PHFU. (*Id.* at 11.) Staff states that only one of three Group 2 projects are complete, and thus recommends placing 67 percent of Group 2 costs, approximately $16,280,152

in PHFU. (*Id.*) Staff states that half the projects in Group 3 are complete, and therefore recommends putting 50 percent of Group 3 facility cost, or approximately $8,282,997, in PHFU. (*Id.*) Staff notes that all projects in Group 4 are complete, and therefore recommends putting none of the Group 4 costs into PHFU. (*Id.* at 12.)

460. Staff states that while Sierra-G has made significant investments into the south Reno second source project, it is not time for ratepayers to cover 100 percent of those expenses, as substantial work still remains on many of the projects involved. (*Id.* at 14.) Staff states that Sierra-G has complete control over the timing of these projects and the timing of the filing of its rate case, and that if Sierra-G wanted these costs covered 100 percent by ratepayers in this current general rate case, it should have scheduled the additional projects to be completed concurrently by this project or simply filed its rate case later. (*Id.*)

461. Staff recommends that the Commission order Sierra-G to allocate $25 million including AFUDC of the costs incurred to date to PHFU until the remaining projects are complete and the anticipated benefits of these projects are realized by ratepayers. (*Id.* at 14, 15.) Staff concludes by recommending that the Commission reclassify approximately $25.093 million for the south Reno connector project from this general rate case and into PHFU. (Ex. 320 at 11.)

Sierra's Rebuttal

462. Sierra begins by correcting the AFUDC accrual numbers proffered by Staff due to an error found in Sierra's AFUDC calculations, and it states that the total AFUDC accrued after December 2022 was $1,734,551. (Ex. 244 at 4.)

463. Sierra further states that Phase I was not capable of being energized and flowing gas when construction was completed in 2022. (*Id.* at 4.) Sierra states that Phase I would not have been able to maintain odorization as required by 49 CFR 192.625(a), as the pipeline was

not properly pickled. (*Id.* at 5.) Sierra states that this pickling process could not be completed for Phase I until Phases II and/or III were fully constructed, and that this construction took longer than expected, but was not due to any wrongdoing on the part of Sierra. (*Id.* at 5-6.) Sierra therefore recommends the Commission allow recovery of $1,734,551 in AFUDC for this project. (*Id.* at 4.)

464. Sierra further disagrees with Staff's recommendation to defer $25.093 million in costs from inclusion in this general rate case and into PHFU, as Sierra states that it reasonably and prudently developed these projects to serve load growth, and that they are used and useful to customers. (Ex. 253 at 4.) Sierra states that Staff's calculation is overly simplistic in that it does not consider facilities already installed and providing service, nor does it consider the base cost of providing customers with any one single benefit. (Ex. 244 at 10.) Sierra maintains that the costs of the south Reno second source project were a prudent investment that is both in-service and benefitting customers. (*Id.* at 15.) Sierra recommends that the $25.093 million suggested for deferral by Staff remain as plant-in-service, allowing Sierra to begin recovery. (*Id.*)

Commission Discussion and Findings

465. The Commission disallows recovery for AFUDC costs incurred on Phase I and Phase II of the project, starting at the end of December 2022, in the amount of $1,735,551. The Commission finds that these phases were effectively complete and did not warrant continuation of accumulating AFUDC. As discussed at hearing, Sierra could have completed the pickling. (Tr. at 674: 7-20.) The Commission rejects Staff's recommendation to reclassify the total $25.093 million as PHFU as the project, excluding the Rainbow Bend 8-inch lateral, is in service and used and useful.

466. The Commission orders Sierra to remove costs associated with the Rainbow Bend 8-inch lateral from its rate base in this general rate case and reclassify to PHFU, as that lateral is not yet used or useful. As a compliance item, Sierra must determine the amount of project costs specific to the Rainbow Bend 8-inch lateral to be removed from rate base as well as any related depreciation expense.

Z. General Rate Case Carry

Staff's Position

467. Staff provides that Sierra is requesting to recovery carrying charges from its 2016 Gas general rate case and 2016 Gas Depreciation Study dockets, totaling $13,230, which would be included in rate base and amortized over three years. (Ex. 318 at 2.) Staff argues that all costs presented for recovery in a docket, including carrying charges, are considered on a case-by-case basis, and that costs placed into a deferred account for later recovery are not automatically given regulatory asset treatment. (*Id.* at 2-3.)

468. Staff states that this issue has been before the Commission previously, and that the Commission denied recovery of these costs because the treatment of these types of carrying costs because if recovery was approved, the funds would also earn the approved ROR, which the Commission has found to be unreasonable. (*Id.* at 3.)

469. Staff therefore recommends that the Commission disallow $13,230 requested by Sierra for carrying charges on expenses incurred in the 2016 Sierra general rate case (Docket No. 16-06007) and the 2016 Gas Depreciation Study (Docket No. 16-06009). (*Id.*)

Sierra's Rebuttal

470. Sierra agrees that the Commission should remove $13,230 in carrying charges for the 2016 gas general rate case and Depreciation study from the calculation of revenue

requirement. (Ex. 250 at 4.) However, Sierra states that this results in an ADIT adjustment of approximately $3,000. (Ex. 250 at Naughton-Rebuttal-3.)

Commission Discussion and Findings

471. The Commission accepts the parties' collective recommendation to remove $10,230 (net of ADIT) for the 2016 Sierra-G general rate case and depreciation study from the calculation of gas revenue requirement.

AA. Unprotected Excess ADIT (Gas)

Sierra's Position

472. Sierra provides that schedule H-CERT-27 reflects the adjustment necessary to include the amortization of unprotected excess deferred income taxes over the years. (Ex. 198 at 7.) Sierra explains that, in H-CERT-27, the Period 1 unprotected balance includes all recaptured excess ADIT amortization since the 2017 tax rate change resulting from the Tax Cuts and Jobs Act. (*Id.*) Sierra represents that the Period 1 unprotected balance was recently adjusted, as an ancillary part of an effort to ensure IRS compliance regarding cost of removal accruals and normalization, to ensure that Sierra's gas and electric balances are correctly reflected in the PowerTax depreciation system. (*Id.*) Sierra further provides that H-CERT-27 reflects the amortization of the cost of removal balance of deficient deferred taxes over the average book asset life of 38.5 years. (*Id.*)

473. Sierra is requesting a three-year amortization period for the Period 1 balance of Unprotected Excess ADIT and a 38.5-year amortization period for the Unprotected Cost of Removal Deficit ADIT balances as of February 29, 2024. (Ex. 125 at I-CERT-27.) As of February 29, 2024, the Period 1 balance of Unprotected Excess ADIT is (-$1.398 million) and the Unprotected Cost of Removal Deficit ADIT balance in $6.071 million. (*Id.*)

Commission Discussion and Findings

474. The Commission notes that Staff pointed out errors related to Sierra-G's Unprotected Excess ADIT in H-CERT-21 and I-CERT-21, which Sierra has agreed with as discussed elsewhere in this Order. However, this is the first opportunity to address the amortization periods for Sierra-G Unprotected Excess ADIT in a general rate case. No party objected to the amortization periods requested by Sierra-G, and accordingly, the Commission approves a three-year amortization period for the Period 1 Unprotected Excess ADIT balance and a 38.5-year amortization period for the Unprotected Cost of Removal Deficit ADIT balance.

BB. Waiver of NAC 704.6546 (Gas)

Sierra's Position

475. Sierra explains that its gas division has a net operating loss recorded in regulatory account 190100. (Ex. 198 at 11.) In Docket No. 24-02027, Sierra requests a waiver of NAC 704.6546, which concerns the use of the separate-entity method by utility members of a consolidated group for the purposes of computing income taxes. (*Id.*) Sierra asserts that it requested the waiver so that Sierra customers are not impacted by the net operating loss that is currently included as an increase to rate base. (*Id.*)

476. Sierra elaborates that the unused net operating loss carryforward balance recorded in regulatory account 190100 was recorded on the balance sheet as a deferred tax asset and is required to be included in rate base to avoid a normalization violation. (*Id.* at 12.) Sierra provides that, as of September 30, 2023, the amount allocated to rate base is $5,455. (*Id.*) Sierra provides that a waiver of NAC 704.6546 would allow this amount to be reduced to zero, which would reduce rate base by $5,455. (*Id.*)

477. Sierra states that its parent company, BHE, did not use the net operating loss on its consolidated 2022 tax return. (*Id.*) Instead, Sierra explains that BHE paid cash to NV Energy in order to compensate Sierra for the use of the loss. (*Id.*) However, Sierra maintains that the requirement to use the separate-entity method prohibits NV Energy from recognizing the receipt of cash and use of the tax net operating loss carryforward at the utility level for regulatory reporting. (*Id.* at 12-13.) Sierra notes that the requested waiver of NAC 704.6546 will not affect the calculation of any other tax balances. (*Id.* at 13.)

478. In response to a Staff data request, Sierra states that it has decided to withdraw its request for a waiver of NAC 704.6546 included in its Application in Docket No. 24-02027. (Ex. 321 at FC-60.) Sierra explains that it is withdrawing its request out of an abundance of caution after becoming aware of a recent Private Letter Ruling by the IRS that creates some ambiguity as to whether Sierra's requested NAC waiver would result in a violation of the IRS normalization requirements. (*Id.*) Sierra states that this withdrawal will result in an increase in rate base of approximately $5,000. (*Id.*) At hearing, Sierra-G confirmed its withdrawal of the waiver request. (Tr. at 533: 13-15.)

Staff's Position

479. Staff recommends that the Commission accept Sierra's withdrawal of its request for a waiver of NAC 704.6546, which would result in a rate base increase of approximately $5,455. (Ex. 321 at 47.) Staff contends that a normalization violation may occur if the NAC waiver was indeed granted. (*Id.* at 46.) Staff elaborates that the IRS has recently issued a Private Letter Ruling which held that reducing a regulated public utility's standalone net operating loss carryforward deferred tax asset by the payments received pursuant to an intercompany tax

allocation agreement would constitute a normalization violation. (*Id.*) Staff notes that this ruling comports with other similar Private Letter Rulings by the IRS. (*Id.*)

Commission Discussion and Findings

480. The Commission accepts Sierra-G's withdrawal of its requested waiver of NAC 704.6546 for the reasons discussed above.

VI. RATE DESIGN

A. D-1 Rate Design Sierra-E

Sierra's Position

481. Sierra states that its D-1 rate design for Sierra-E is contained in its preferred Statement O, shown in Ex. Prest Direct-3, workpaper 5, page 1. (Ex. 274 at Prest-Direct-3.) Sierra also outlines several other D-1 rate design proposals in its other prepared Statement Os, shown in Ex. Prest Cert-4, Cert-5, Cert-6, Cert-7, and Cert-8, workpapers 5 (for all), page 1. (Ex. 275 at Prest Cert 4-8.)

482. Sierra states that its forecasts indicate the Base Tariff Energy Rate ("BTER") and DEAA rates will continue to decline and are estimated to decrease overall effective rates by approximately 19 percent, which is greater than Sierra's proposed 9 percent overall effective rate increase in this general rate case. (Ex. 232 at 13.) Sierra states that the result for customers is an overall forecasted decrease in effective rates of approximately 10 percent by the end of 2024. (*Id.* at 13.)

483. Sierra states that, assuming an average monthly usage of 759 kWh for a residential customer, an average monthly bill was $105 in 2022, $118 in 2023, and is forecasted to be $111 in 2024, which includes the proposed general rate case increase and forecasted BTER and DEAA rate decreases. (*Id.* at 14.)

484. Sierra recommends the implementation of a 0 percent capped class revenue mechanism for the D-1 and DM-1 customer classes, a 5 percent capped class revenue mechanism for all other fully bundled customer classes, and the implementation of a 9.6 percent floor class revenue mechanism for all customer classes. (*Id.* at 18.) Sierra also proposes the setting of a BSC for all customer classes. (*Id.*)

Staff's Position

485. Staff recommends that the Commission find that the concepts and calculations underpinning Staff's proposal for the Sierra-E rate design for the residential customer class D-1 are reliable and valid. (Ex. 327 at 5-6.) Staff proposes adding a tier in the volumetric charge of customer class D-1. (*Id.* at 6.) Staff states given a BSC, variable charge A is the price per kWh consumption at or below a certain kWh consumption cutoff, and variable charge B is above the cutoff. (*Id.*) Staff states it created a tool informing the development of the concepts and calculations underpinning its proposal, and Staff further states that the tool has an interface file enabling a user to nominate a cutoff and to assess the reasonableness of a rate design across different kWh consumption levels. (*Id.*)

Sierra's Rebuttal

486. Sierra disagrees with the proposal to implement a tiered rate structure because it would be economically inefficient and a step backwards in creating cost-based rates. (Ex. 283 at 20-21.) Sierra is concerned that it would take too much time to implement a tiered rate structure before the deadline of October 1, 2024. (*Id.* at 21.)

487. Sierra also does not agree with a tiered rate structure because Sierra says that customers find them confusing, there are no emergent conditions that call for a tiered rate

structure, tiered rate structures inherently result in subsidies among customers, and that a tiered rate structure has the potential to further harm low-income customers. (*Id.* at 21-22.)

Commission Discussion and Findings

488. The Commission declines to implement Staff's proposed tiered D-1 rate structure. The Commission agrees with Sierra that this would not be practical to implement in this docket, and it is not an efficient intermediary step to proposing or establishing a large residential customer rate class.

B. Interruptible Service-2 ("IS-2")

Sierra's Position

489. Sierra provides that IS-2 rates are set outside of a general rate case pursuant to NRS 704.225 and 704.675. (Ex. 232 at 20-21.) Sierra states that these rates are set in a separate docket and at the lowest average rate of different utilities in the state. (*Id.* at 21.) Sierra states that the lowest average rate is set below the cost of service of the class, which results in the IS-2 class receiving a subsidy of approximately $14 million in this filing. (*Id.*)

490. Sierra also provides that the IS-2 tariff is an interruptible schedule that provides a lower rate to agricultural irrigation customers, as long as the IS-2 customer agrees to allow Sierra a right to interrupt service to irrigation pumps under conditions approved by the Commission. (Ex. 268 at 11.) Sierra states that if the customer does not interrupt service when requested by Sierra, the customer is subject to penalties. (*Id.*) Sierra provides that the current penalty for a first failure to interrupt is a billing to the customer at the IS-1 rate for the entire monthly billing period, and a second failure to interrupt results in a bill to the customer at the IS-1 rate for the remainder of the irrigation season, from March 1 to October 31. (*Id.* at 11-12.)

491. Sierra states that it is now proposing a modification to the current penalty structure by charging customers the published Energy Imbalance Market ("EIM") prices for any usage during an emergency event. (*Id.* at 15.) Sierra argues that this proposal will simplify the determination of appropriate penalties and will charge customers higher rates only for those periods that an emergency event is called and the customer does not curtail service. (*Id.* at 15-16.) Sierra states that revenue collected under these charges would be accounted for through the deferred energy mechanism and would offset any energy purchased during the event hours for the benefit of all other customers. (*Id.* at 16.) Sierra states that the intent of this new penalty structure is to ensure that legislatively mandated IS-2 customers pay for the higher cost of energy that may be paid by Sierra and other customers during an emergency event. (*Id.*)

492. Sierra argues that this approach is less punitive than the current penalty structure and is more tied to actual usage during emergency event hours. (*Id.*)

Staff's Position

493. Staff provides that schedule IS-2 provides a lower rate to irrigation customers between the months of March and October, with the provision that the customer agrees to be interrupted by utility direct load control or self-interrupt service provided under the schedule. (Ex. 328 at 33.) Staff further provides that when Sierra is unable to interrupt load, the first failure results in billings to the customer at the IS-1 rate for the entire monthly bill. (*Id.* at 34.) Sierra is proposing that the second failure to interrupt load result in a bill to the customer for the entire irrigation season, charged at the IS-1 rate. (*Id.*) Staff provides that Sierra proposes to charge customers that fail to curtail published EIM prices for any usage during an emergency event. (*Id.*)

494. Staff is concerned that it may be difficult for the average IS-2 customer to find the correct EIM prices, as the webpage that contains the prices and how they are applied is difficult to navigate for someone unless they are familiar with the appropriate language. (*Id.*) Staff argues that changing the IS-2 tariff may simplify the determination of a penalty for Sierra, but it will make things more complex for the customer because the customer will not know what the penalty is without research or assistance from Sierra employees. (*Id.*)

495. Staff further argues that Sierra has not provided adequate discussion or detail to support Sierra's claim that the proposed penally will lessen overly prohibitive financial burdens that may be caused by the customer being moved to the IS-1 rate for an entire season. (*Id.* at 35.) Staff argues that, given the broad implications of changing the IS-2 penalty, a separate docket would be needed wherein this proposal can be properly vetted by Staff and other interested parties. (*Id.*)

496. Staff therefore recommends that the Commission deny Sierra-E's request to modify the IS-2 customer class tariffs in this filing and require Sierra to file an application to modify the IS-2. (*Id.*)

Sierra's Rebuttal

497. Sierra argues that a general rate case is the appropriate proceeding venue for the Commission to determine whether to update the IS-2 tariff. (Ex. 281 at 4.) Sierra acknowledges that the presentation and communication of prices to IS-2 customers would require additional effort from Sierra to ensure that customers understand the impact of this information on a timely basis. (*Id.* at 4.)

498. Sierra proposes an alternative to address Staff's concerns, and that would be to charge customers a higher fixed rate for usage during emergency events. (*Id.*) Sierra states that

using a fixed multiplier would achieve a rate near the level of prices that could be expected in an emergency event, and the multiplier would be published in Sierra's Statement of Rates so that customers can more easily know what rate to pay during such an event. (*Id.* at 5.) Sierra also states that approving this change would provide IS-2 customers more control over their final penalty amount, and re-focus on event times instead of past usage. (*Id.*)

Commission Discussion and Findings

499. The Commission agrees with Staff that a separate docket to address changes in the IS-2 penalty would be more appropriate than making changes in the instant docket. The Commission finds that doing so would allow for a more robust discussion and input from parties. Accordingly, the Commission denies Sierra's proposed changes to its IS-2 tariff.

C. Basic Service Charge ("BSC")

Sierra's Position

500. Sierra provides that the BSC is the fixed charged rate component of a customer's bill and is intended to recover costs that are fixed in nature, such as those related to meters, customer accounting, and customer service. (Ex. 276 at 17.)

501. Sierra-E provides that it is proposing to increase the BSC for the D-1 residential class to $45.30 for the D-1 residential class. (Ex. 275 at 10.) Sierra-E also provides that it is proposing to increase the BSC for the multi-family residential (DM-1) to $18.80 for the DM-1 class. (*Id.* at 10.) Sierra is also proposing to increase the small commercial class BSC (GS-1) from $32.30 to $50.60. (*Id.)*

502. Sierra-G provides that the current renewable natural gas ("RNG") customer class BSC is $14.00, and Sierra is proposing to increase the charge for that class to $18.00. (Ex. 262 at 23.) Sierra-G is also proposing to increase the BSC for the small commercial and industrial

natural gas ("SCNG") customer class from the current rate of $18.00 to $40.00. (*Id.* at 23.) Sierra-G further proposes to decrease the large commercial and industrial natural gas ("LCNG") customer class BSC from the current rate of $1,000 to $602. (*Id.*)

503. Sierra-E states that it is proposing to include 100 percent of residential customers' distribution costs in the BSC. (Ex. 232 at 22.) Sierra-E argues that increasing the BSC as such helps to stabilize customer bills over the year because the resulting usage-based rate decreases when the BSC increases. (*Id.* at 22.) Sierra-E further argues that a higher BSC creates more predictability in customer bills, and because of the resulting decrease in usage-based rate, specifically decreases bills when usage is highest. (*Id.*) Sierra-E also argues that the movement to cost-based levels sends the appropriate price signals of the costs that are fixed in nature and do not vary with usage, which results in a limiting of intraclass customer subsidies. (*Id.*) Sierra states this is especially impactful for the calculation required when combining fully bundled residential customers and NEM customers. (*Id.*)

NCARE's Position

504. NCARE does not agree with Sierra's proposal to increase the BSC to $45.30 because it will impair customer control over their power bills, disproportionately impact low-usage customers, and it sends the wrong price signal and reduces customer incentive to engage in energy efficiency and conservation. (Ex. 1000 at 6.) NCARE disagrees with Sierra's argument that a higher BSC would reduce volatility in customer bills, because the volatile fluctuation of bills is primarily driven by fuel costs, which are not addressed in this Docket. (*Id.* at 6.) NCARE also states that its customers do not see a volumetric price incentive to reduce consumption, future system costs and bills will grow due to higher energy loads. (*Id.*)

505. NCARE disagrees with Sierra's argument that increasing the BSC will help recover a revenue shortfall regarding NEM customers, because it shifts the burden of recovery onto non-NEM customers instead of specifically targeting the NEM customers. (*Id.* at 15.)

506. NCARE states that the BSC is not an effective price signal because customers cannot change their energy consumption for a fixed charge, such as the BSC. (*Id.* at 17.) NCARE states that Sierra's proposed BSC increase is counterproductive as a price signal, because a customer would be charged the same amount even if the customer used less energy, which encourages energy waste. (*Id.*)

507. NCARE states that the BSC should only include costs that have historically been recovered to serve the individual customer, such as the customer's meter, billing, and accounting services. (*Id.* at 23.) NCARE states that fixed costs associated with distribution/transmission, Rule 9 costs, and uncollectable costs are more appropriately recovered in the volumetric charge. (*Id.*) NCARE argues that customers need agency over their bills, and an increase to the BSC will prevent customers from having that agency. (*Id.*) NCARE states that if Sierra's proposed increase is allowed to move forward, it will reduce customer agency, increase subsidies for high-usage residential customers, and possibly have consequences for Sierra's demand side management ("DSM") program. (*Id.*)

508. NCARE therefore recommends that the Commission deny Sierra-E's request to increase the BSC for all residential customers and the associated voluntary rates offered to this customer class. (*Id.* at 24.)

SEIA's Position

509. SEIA disagrees with Sierra-E's proposed BSC increase because SEIA claims it is extreme, unsupported, and runs counter to Nevada policies. (Ex. 900 at 102.) SEIA asserts that

Sierra is attempting to work around legislative protections for NEM customers that prevent those customers from being charged punitive rates, and it is being done under the guise of bill stability. (*Id.*) SEIA states however that this proposal runs counter to fundamental rulemaking tenants such as gradualism and customer acceptance and would harm all customer who use below average amounts of energy. (*Id.* at 102-103.)

510. SEIA states that Sierra has not surveyed or otherwise asked customers about their preference for lower bills or having more control over bills. (*Id.* at 105.) SEIA states that, similarly, Sierra did not survey or otherwise ask NEM customers about their preferences regarding higher and/or more stable bills. (*Id.*)

511. SEIA argues that Sierra's motivation for this disruptive rate change to include all customer and distribution costs in a fixed BSC is to mitigate the revenue erosion that occurs when new customers install NEM systems. (*Id.* at 3.) SEIA disagrees with Sierra's arguments that NEM customers are more expensive to serve than non-NEM customers, because Sierra's cost allocation methodology and marginal cost study ("MCS") contain fundamental flaws that lead to Sierra's conclusions. (*Id.* at 4.) SEIA states that these flaws include the use of imputed load shapes that do reflect the physical use of the grid by NEM customers, errors in the meter cost installation expenses, and customer accounts and service expenses that are poorly supported. (*Id.*) SEIA states that when these flaws are corrected, NEM customers have a cost of service that is 30 percent lower than non-NEM customers. (*Id.*)

512. SEIA recommends that the Commission reject Sierra's BSC increase because it is based on limited customer feedback, Sierra already offers a program that eliminates bill variability, and it includes costs that should not be included in a fixed charge. (*Id.* at 115.) SEIA states that this increase to the BSC would result in the highest BSC in the country, and that a

lower volumetric rate would induce additional usage that would not reflect all appropriate costs. (*Id.*)

513. SEIA also calls for the Commission to create a virtual power plant ("VPP") that will allow Sierra to provide additional capacity at specific times and geographic locations to support the grid. (*Id.* at 126.) SEIA states that an ideal VPP would include performance-based programs, batteries that can export to the grid, no opt-out fee or limit, events targeted for no more than three hours, stackable performance payment, third-party aggregators, a locked-in payment of five years, a focus on summer events only, a maximum of 60 events per year, and a minimization of metering costs. (*Id.* at 127-128.) SEIA notes that Sierra already has a pilot battery storage program, but SEIA argues that program should be modified to more closely adhere to the parameters described above, and that Sierra should modify the proposed payment level to reflect a more balanced split of benefits between the VPP owner and the rest of the rate base. (*Id.* at 130.)

BCP's Position

514. BCP recommends that the that the Commission reject Sierra's proposed increase in residential customer charges for the D-1 and DM-1 classes. (Ex. 411 at 2.) BCP states that Sierra is proposing a 175 percent increase to the D-1 BSC, which would make it the highest BSC in the United States by a considerable margin. (*Id.*)

515. BCP disagrees with Sierra's assertion that this higher BSC will help stabilize customer bills throughout the year because it does not address the volatility of gas prices reflected in the BTER and DEAA in the past two years. (*Id.* at 3.) BCP states that as long as natural gas remains a key component of power generation for Sierra, its customers will be subject to volatility of gas prices. (*Id.*) BCP further states that there are already mechanisms in

place to provide bill stability, such as Sierra's Equal Pay Program, which averages out customer bills over the span of a year. (*Id.* at 3-4.)

516. BCP also disagrees with Sierra's argument that a higher BSC will cover the deficit of NEM customers' that are not covering their share of fixed costs. (*Id.* at 3.) BCP states that, for one, NEM customers constitute 3.5 percent of all residential customers, and that their TOU system peak occurs later in the day than all other residential customers. (Ex. 409 at 8.) BCP states that without NEM customers, residential peak load would be much higher, which would increase Sierra's overall distribution costs. (*Id.* at 9.) BCP states that raising rates for all classes to offset alleged shortfalls from 3.5 percent of the entire residential class is nonsensical. (*Id.* at 11.)

517. BCP is concerned that the proposed increase will, in turn, punish energy conversation and possibly reward higher consumption, reduce participation in distributed energy resources ("DER") and demand-side management ("DSM") programs, harm low-income customers using FlexPlay, be unpopular with customers, and result in higher utility rates over time. (Ex. 411 at 4.)

518. BCP recommends that the Commission reject Sierra's proposed increase the BSC for D-1 and DM-1 customers, and instead reduce the BSC to $12.50 for the D-1 class and $6.00 for the DM-1 class for Sierra-E. (*Id.* at 2.) BCP also recommends reducing the BSC for Sierra-G from $14.00 to $12.00, because according to BCP's analysis, natural gas residential customer costs are roughly $8. (Ex. 409 at 28.) BCP recommends $12.00 in accordance with reasonable cost causation and the promotion of conservation. (*Id.*)

Staff's Position

519. Staff is concerned that Sierra's proposed increase to the BSC for residential customers will benefit those that use more rather than those who use less, that a reduction of the usage-based rate will have a negative impact, and that so many customers view this increase negatively. (Ex. 328 at 23-24.) Staff also states that this new BSC is effectively an intraclass subsidy. (*Id.*)

520. Staff doesn't disagree that a higher BSC will reduce bill volatility for customers, but Staff does state that Sierra-E should rather be focusing on residential customers who use an exorbitant amount of energy consumption and use rate design to encourage those customers to use less. (*Id.*)

521. Staff is concerned that Sierra is looking to recover distribution costs with this BSC increase, something Staff has not seen before in a rate case. (*Id.* at 25.) Staff is concerned that if the Commission were to accept this BSC increase based on distribution costs, it could open the door for Sierra-E or other utilities to include transmission and generating costs into the BSC in future filings. (*Id.* at 26.) Staff states that Sierra's arguments regarding NEM customers is in response to the competition it faces in the market, which begs the question of what else would be proposed by Sierra-E to deal with competition it faces (and will face) in the market. (*Id.*)

522. Staff does not support Sierra-E's proposed BSC increase, and instead advocates for gradual increases to the BSC. (*Id.* at 29.) Staff proposes instead that the BSC for D-1 be increased to $18.25 and the BSC for DM-1 be increased to $9.00. (Ex. 328 at ML-9.) Staff recommends for non-residential classes an increase of 10.5 percent. (*Id.* at ML-9.) Staff is not opposed to the rate design for Sierra-G. (*Id.* at 38.)

Sierra's Rebuttal

523. Sierra states that it continues to support increasing the residential BSC at cost-based levels. (Ex. 283 at 3.) Sierra states that placing 100 percent of distribution costs in the residential BSC would align it with all other rate classes. (*Id.* at 5.) Sierra states that primary distribution-demand costs are driven by non-coincident and coincident demand, with facilities closest to the customer driven by customer maximum demands. (*Id.*) Sierra states that from a cost-causation perspective, the primary distribution costs are more appropriately recovered through a fixed charge mechanism like the BSC. (*Id.*)

524. Sierra states that it has advocated for distribution costs to be placed into the BSC in previous dockets, including in its previous general rate case where the Commission approved a BSC that included 14 percent of primary distribution costs. (*Id.* at 7.) Sierra states that BCP's analysis is flawed as it removes cost categories from BSC that have long been included. (*Id.* at 9.) Sierra states that, using the calculations it presented in 2022 regarding the BSC, a BSC of at least $26.85 is the result. (*Id.*)

525. Sierra states that Staff and NCARE's assertions that the increased BSC will only benefit high-usage customers because high-usage does not mean that the customer is high-income, and that Sierra's residential class includes a variety of customer types. (*Id.* at 15.) Sierra states that its proposed BSC increase and a volumetric charge that reflects costs related to usage minimizes intraclass subsidies. (*Id.*)

526. Sierra disagrees with Staff's proposal to limit Sierra's BSC to increase of 10.5 percent. (*Id.* at 25.) Sierra states, that for uniform movements of BSC across all classes, it is more appropriate to use a percent increase towards cost-based rates. (*Id.*) Sierra states that its proposed cap for non-residential classes is 15.5 percent. (*Id.*)

527. Sierra disagrees with BCP's calculations regarding the BSC for Sierra-G, while noting that Staff supports the BSC for Sierra-G. (Ex. 280 at 10.) Sierra states that BCP is simply removing costs by labeling them "inappropriate" without a discussion of the appropriateness of the charge, historical context, or a discussion of ratemaking principles. (*Id.* at 11.)

528. Sierra states that the increased BSC reflects the cost-based charges for customers, facilities, and distribution expenses in a fixed monthly charge because it results in equitable treatment amongst all customers, stabilizes monthly bills, and is a first step to responding to the Commission's order in the 2023 Nevada Power general rate case to propose alternative solutions to the AB 405 NEM regulatory asset. (Ex. 286 at 11.) Sierra estimates that bills will decline over the next two years. (*Id.* at 7.)

529. Sierra states that its proposed increase to BSC (from $14 to $18) for Sierra-G decreases the usage-based rate from $0.21197 to $0.13849 and supports the movement of the monthly BSC towards cost-based levels. (Ex. 287 at 2.)

530. Sierra further states that BTER and DEAA rates are forecasted to decline and are estimated to decrease overall customer effective rate by approximately 39 percent by the end of 2024 in comparison to the end of 2023, which is greater than the proposed 6 percent overall effective rate increase proposed by Sierra in this general rate case. (*Id.*) Sierra further forecasts an overall decrease in effective rates of approximately 33 percent by the last quarter of 2024. (*Id.* at 3.) Sierra states that this increase still gives customers agency and control over their bill, as over 60 percent of a customer's bill will be based volumetric charges. (*Id.* at 3-4.)

Commission Discussion and Findings

531. The Commission rejects, in part, Sierra's proposed BSC increase. The Commission acknowledges that an increase to the BSC provides value to both Sierra and its

ratepayers; however, the Commission finds that the magnitude of the increase, as proposed, is not appropriate at this time because it would disproportionately affect low-usage customers. Such a proposal does not send the proper price signals to customers, nor does it encourage energy efficiency and conservation. Currently, the basic service charge is $16.50 for the D-1 residential service class and $8.00 for the DM-1 multi-family residential service class. The Commission finds Sierra's 175-percent increase to the D-1 BSC inordinately large and not in the public interest. An increase of such a magnitude, coupled with being an ineffective tool to alleviate the significant volatility in customer bills due to fuel prices, would significantly adversely affect ratepayers and would not result in just and reasonable rates. Further, such an increase does not embody the rate-making concept of gradualism. The Commission finds that an increase of $28.80 to the fixed portion of a residential customer's bill, as proposed by Sierra, would likely cause rate-shock and would discourage energy efficiency and conservation.

532. With regard to Sierra's argument that the proposed decrease to the usage-based rate will offset the proposed increase to the BSC, the Commission disagrees and finds that the reduction in the volumetric rate will not offset the impact of the proposed BSC increase for all customers, namely those with below-average electricity usage. The Commission recognizes that this type of proposal can be beneficial to customers but believes that the proportions of the proposal require adjustment to avoid unreasonable impact on a significant number of customers. While the Commission recognizes that principles of utility ratemaking generally promote sending proper price signals through the adoption of rates that reflect the costs of serving customers, the Commission finds that Sierra's BSC proposal is too aggressive at this time and that customers may interpret a large downward adjustment in volumetric rates as a signal to increase their use of, rather than conserve, electricity.

533. The Commission finds that NV Energy's BSC proposal would disproportionately affect low-usage customers and further finds that most of the volatility in a customer's bill is due to fuel costs, which are not addressed in this docket. The Commission views the proposed increase as extreme and unsupported because it would impair control over customers' power bills, disincentivize customers to reduce consumption, and potentially increase future system costs due to higher energy loads.

534. The Commission notes that different intervenors offered their own BSC proposals. The Commission finds that the proposed decrease in the BSC offered by BCP does not result in just and reasonable rates because the amount proposed by BCP is too low. At this time, the Commission does not find that it is appropriate to lower the BSC to $12.50. The Commission conversely finds that there is a need to increase the BSC to cover increasing costs to serve customers. Staff advocates for a BSC for the D-1 rate class to increase to $18.25 and for the DM-1 rate class's BSC to increase to $9.00. The Commission finds Staff's proposal to be much more reasonable and equitable, as opposed to Sierra's and BCP's proposals, because it achieves the goal of addressing the increased costs to serve customers but does not overreach. The Commission finds that Staff's proposal maintains gradualism as costs increase.

535. With regard to adding distribution costs to the BSC, the Commission is hesitant to add such costs into a charge that historically has been used to recover costs related to meters, customer accounting, and customer service. The Commission appreciates Staff's concerns that distribution costs have not been added to the BSC before in the state of Nevada and that such a practice is not normal in the industry. The Commission understands Sierra's position that distribution costs are more appropriately recovered through a fixed charge mechanism than

through a volumetric charge, but the Commission declines to expand the BSC to include costs beyond those associated with meters, customer accounting, and customer service.

536. The Commission sets the BSC for the residential D-1 class at $18.50, and the Commission sets the BSC for the multi-family residential DM-1 class at $9.25. The Commission finds that these BSCs are just and reasonable. After considering all of the BSC proposals presented by intervenors, the Commission finds that Staff's proposals balance the need to address increasing costs with maintaining gradualism. However, the Commission believes that a slight increase of 25 cents above Staff's proposal for the D-1 and DM-1 class more fairly balances the need to cover increasing costs to serve customers while still maintaining the ratemaking principal of gradualism. The Commission finds that the BSCs for all other rate classes in Ex. 328 at Attachment ML-9 result in fair and reasonable rates because the Commission believes that Staff's proposal of increasing these BSCs by 10.50 percent is appropriate and also maintains gradualism. Thus, the BSCs for the other rate classes are ordered to be set as follows: GS-1 to be set to $35.75, GS-2S to be set to $15.50, GS-2P to be set to $21.80, GS-2T to be set to $81.00, GS-2S TOU to be set to $30.25, GS-2P TOU to be set to $137.00, GS-2T TOU to be set to $237.00, GS-3S to be set to $593.00, GS-3P to be set to 676.50, GS-3T to be set to $722.50, GS-4 to be set to $1,682.25, OGS-1 to be set to $35.75, OGS-2S to be set to $30.50, OGS-2P to be set to $82.25, OGS-2T to be set to $91.25, IS-1 to be set to $35.00, WP to be set to $4,120.50, OD-1 to be set to $18.25, OD-1 DDP to be set to $10.50, OD-1 CPP to be set to $18.25, OD-1 CPP-DDP to be set to $18.25 ODM-1 to be set to $8.90, ODM-1 DDP to be set to $7.00, ODM-1 CPP to be set to $9.00 ODM-CPP-DDP to be set to $9.00, and OIS-1 to be set to $35.00.

537. With respect to the residential BSC for Sierra-G, BCP recommended a decrease to the BSC from the current $14.00-per-month charge. This is counter-intuitive as Sierra-G has not filed a general rate case in eight years. Inflation factors alone would increase the monthly charge. No other party takes issue with Sierra-G's proposal to increase the BSC from $14.00 per month to $18.00 per month. However, as that would be a significant increase to ratepayers, the Commission finds that a BSC for the RNG class of $16.00 is appropriate because it allows for gradualism in rates while allowing Sierra-G to cover additional costs since its last general rate case in 2016. Part of the issue is that Sierra-G is not required to file a general rate case on a prescribed statutory schedule, and thus extended periods of time between rate cases may occur, which result in significant rate-design challenges. The costs to serve Sierra's gas customers in 2016 were substantially different than those costs in 2024. Sierra proposes to increase the BSC for the SCNG customer class from the current rate of $18.00 to $40.00. Sierra also proposes to decrease the LCNG from the current rate of $1,000 to $602. In the course of the instant docket, none of the parties took issue with these proposals. Given that none of the proposals were contested or objected to by other parties, the Commission adopts the proposed increase to the BSC for the SCNG class and the decrease to the BSC for the LCNG class.

538. The Commission declines to address any VPP project or procedures in this general rate case. A VPP proposal is best suited for review in an integrated resource plan proceeding.

D. Change Summer On-Peak Time of Use ("TOU") Period

NCARE's Position

539. NCARE states that the traditional purpose of TOU rates is to reduce demand during peak periods, encourage consumption in off-peak periods, and ensure that all customers

pay the relevant costs for power usage at different time periods. (Ex. 1000 at 39.) NCARE states that this is achieved by providing a price signal directly to customers that discourages consumption during specified hours via a higher volumetric price. (*Id.* at 39.)

540. NCARE states that there are very few TOU customers for Sierra currently, but that there are many benefits to expanding the number of customers on TOU rates. (*Id.* at 40-41.) NCARE states that TOU rates encourage load-shifting and conservation, which leads to lower customer bills, reduced wholesale market prices, deferred capacity investments in generation and transmission, better integration of variable renewable resources, reduced pollution, and it gives customers more agency over their bills and consumption. (*Id.* at 41-42.)

541. NCARE states that a successful TOU rate should be designed to provide customers with the ability to shift their movable load out of the on-peak hours and the confidence that they will be able to save money on their electric bill. (*Id.* at 47.) NCARE states that multiple studies show that the shorter the window is for peak hours, the more effective customers are in shifting their demand out of it. (*Id.*) NCARE states that customer surveys indicate a preference for a peak period not exceeding four to five hours, even if that means peak prices will increase. (*Id.*)

542. NCARE states that the current residential TOU rate structure offered by Sierra contradicts many TOU best practices, and that it may not be effective in meeting policy goals or encouraging enrollment. (*Id.* at 52.) NCARE recommends that the Commission order Sierra to reduce the length of the proposed on-peak from six hours to three hours, and the peak window should occur from 6:00 p.m. to 9:00 p.m. between June 1 and September 30. (*Id.* at 53, *see also* Ex. 1001 at 8.) NCARE states that most customers cannot or will not fully shift their daily energy use behavior out of the proposed six-hour window, as it is too long. (Ex. 1000 at 53.)

543. NCARE states that while Sierra is not proposing to make changes to its residential TOU schedule in this Docket, the time is ripe for Sierra to change it anyway, as the Commission recently approved NCARE's TOU adjustments as applied to Nevada Power in Docket No. 23-06007. (*Id.* at 54.) NCARE states that similarly adjusting Sierra's TOU rate schedule in this case would bring the two service territories into alignment and reduce customer confusion. (*Id.*, *see also* Ex. 1001 at 9-10.)

Staff's Position

544. Staff states that a six-hour peak period is inhibiting enrollment in the optional TOU schedules, as customers are less willing to enroll in a TOU schedule and less able to respond if the on-peak period is too long. (Ex. 326 at 3.)

545. Staff states that, additionally, a shorter on-peak period would allow Sierra to use a higher price differential, providing a greater incentive for customers to shift load from the highest-cost hours. (*Id.* at 3.)

546. Staff states that current customer participation in Sierra's TOU rates is low, but high participation in this rate schedule is important because it encourages customers to shift flexible load from Sierra's high-demand and higher-cost periods to lower-cost periods when there is less demand. (*Id.* at 5.) Staff states that TOU rates can help Sierra accommodate increased renewable energy generation. (*Id.*)

547. Staff recommends an on-peak period of 6:01 p.m. to 9:00 p.m., and that Sierra should delay its new TOU rollout until the Commission issues an order in this docket, so that the correct on-peak hours can be included. (*Id.* at 6.) Staff states that a 6:01 p.m. to 9:00 p.m. on-peak period would align Sierra's residential TOU schedules with Nevada Power's. (*Id.* at 7.)

Sierra's Rebuttal

548. Sierra states that it is not proposing changes to its TOU period definitions or schedules, and that it prefers the definitions adopted by the Commission in Docket No. 22-06014. (Ex. 285 at 4.) Sierra argues that changes to TOU period definitions should occur infrequently, and only when system load has changed in a way that necessitates such a move. (*Id.* at 5.) Sierra states that the most recent TOU period changes happened on January 1, 2023, and that changing the period definitions again so soon would impact customer education and Sierra's marketing measures undertaken to publicize the prior changes. (*Id.* at 5.)

549. Sierra disagrees with NCARE and Staff's argument that there is a benefit to aligning Sierra's TOU period definitions with Nevada Power's. (*Id.* at 6.) Sierra argues that such alignment only benefits those who work in rate design or other functions within Sierra, and that customers in northern Nevada are not impacted by rate design in southern Nevada, and vice versa. (*Id.*) Sierra states that it is rare for one customer to have accounts in both service territories. (*Id.*)

550. Sierra states that a much more important kind of alignment is that of residential and commercial TOU period definitions. (*Id.*) Sierra states that any non-alignment between the residential and commercial TOU period definitions can create confusion for a customer paying both residential and commercial rates in the Sierra service territory, as the customer would have to monitor two different TOU periods. (*Id.*)

551. Sierra states that its current TOU periods accomplish the primary goals for TOU design, which are to incentivize customers to avoid/limit usage during peak demand and to incentivize customers to shift usage out of the highest-cost hours expected to occur over the year. (*Id.* at 7.)

Commission Discussion and Findings

552. The Commission agrees with NCARE's and Staff's proposals to shorten Sierra's peak TOU period to three hours, from 6:00 p.m. to 9:00 p.m. The Commission finds that this time length is in line with TOU rates and period lengths in other jurisdictions and for Nevada Power, and further sends the correct price signal to customers. The Commission notes that Sierra's system still experiences high loads during the 3:00 p.m. to 6:00 p.m. window, but customer use of solar power has assisted in meeting demand during that time. Thus, Staff's proposal is approved, as adjusted from 6:00 p.m. to 9:00 p.m.

E. DOS GS-3T New Rate Schedule

SEA's Position

553. SEA provides that, under the current framework, Sierra assigns NRS 704B the same Inter-class Rate Rebalancing ("IRR") charge as calculated for the otherwise applicable bundled rate schedule. (Ex. 702 at 1.) SEA states that this treatment is not justified, however, because NRS 704B customers do not purchase the same services as customer receiving service under the otherwise applicable rate schedules, which results in inequitable rate impacts. (*Id.*)

554. SEA also provides that the sole DOS GS-3T customer pays $29,699 per year in ancillary charges associated with Rule 9 facilities, and Sierra is proposing to increase those charges by 124.8 percent. (*Id.* at 1-2.) SEA states that Sierra then applies the IRR on top of these charges, which would assess a $1,973,536 charge to the sole DOS GS-3T customer. (*Id.* at 2.) SEA argues that this is unreasonable and disproportionate relative to the Rule 9 charges that the customer is paying. (*Id.*)

555. SEA states that NRS 704B customers have paid significant impact fees to hold other ratepayers harmless from their decisions to unbundle their electric services, and the NRS 704B process is producing overwhelming benefits for bundled-service customers. (*Id.*) SEA

states that requiring NRS 704B customers to subsidize the energy, generation, and transmission costs of bundled-service customers through the IRR upsets the risk that those customers are assuming by receiving service pursuant to NRS 704B. (*Id.*)

556. SEA argues that the sole schedule DOS GS-3T customer is unlike any other because it is not purchasing any retail services from Sierra, because it receives power from a provider of new electric resources delivered at transmission-level voltages through NV Energy's Open Access Transmission Tariff ("OATT"). (*Id.* at 6.) SEA states that these Rule 9 charges being paid by the sole schedule DOS GS-3T customer have no relationship to the distribution services that are provided to customers on the bundled schedule GS-3T. (*Id.*)

557. SEA argues that it is not reasonable to tie the schedule DOS GS-3T customer to the bundled schedule GS-3T because it is not necessary to tie the two schedules together for ratemaking purposes. (*Id.*) SEA argues that this may be necessary for other NRS 704B customers, but it is not necessary for the schedule DOS GS-3T customer because that customer's rates are based on the customer-specific facilities that it self-funded under Rule 9, as well as the portion funded by Sierra. (*Id.* at 7.) SEA argues that because the rates that the sole DOS GS-3T customer pays have no relationship to the distribution rates paid by the customers on bundled schedule GS-3T, there is no nexus for tying the two schedules together. (*Id.*)

558. To address these issues, SEA recommends that the sole Distribution Only Service ("DOS") customer in the DOS GS-3T schedule should be transitioned to a new rate schedule, DOS-T, which is applicable to transmission-voltage NRS 704B customers limited to Rule 9 facilities reimbursements. (*Id.*) SEA states that, regardless of whether a new schedule number is assigned, it should be exempt from the IRR. (*Id.*)

Sierra's Rebuttal

559. Sierra disagrees with SEA's recommendation to create a new rate class because the total GS-3T cost-based distribution rates are calculated using both fully-bundled and DOS customer costs, which does consider the distribution costs of the sole DOS 3T customer. (Ex. 283 at 36.) Sierra states that 64 percent of the marginal customer costs for the combined GS-3T class is related to customer services, with most of those costs coming from individualized services provided by Sierra's major accounts department. (*Id.* at 37.)

560. Sierra disagrees that the cost of the BSC for transmission-level DOS customers is duplicative of the OATT rate because DOS customers have two completely different sets of bills, customer service costs, and distribution rates. (*Id.*) Sierra states that the DOS GS-3T customer should not be exempt from the BSC because Sierra expends time and resources supporting that customer, and the customer should pay for that cost just like fully-bundled customers. (*Id.*)

561. Sierra states that it is unclear whether SEA's newly-proposed class would include one customer or several. (*Id.* at 38.) Sierra states that while SEA is proposing only one customer be included in this new class, Sierra currently has seven customers in the DOS transmission class, and it is unclear why those other customers would be excluded from this newly-proposed rate schedule. (*Id.*)

562. Sierra disagrees with implementing this new class and also disagrees that DOS GS-3T customers should be allowed to avoid paying their BSC or IRR. (*Id.*) Sierra acknowledges that transmission-voltage-level facilities are unique to each customer, but that is why Sierra performs the Customer Specific Facilities Study ("CSFS"), which calculates the facilities charges separately for transmission-voltage-level customers. (*Id.* at 38-39.) Sierra states that these costs do not differ, whether the DOS customer is fully bundled or not, so Sierra does not see a reason why the charges should be different. (*Id.* at 39.)

Commission Discussion and Findings

563. The Commission declines to order Sierra to establish a new DOS GS-3T customer class as a standalone rate class. The Commission finds Sierra's testimony persuasive in rebutting SEA's proposal. The Commission finds that a general rate case establishes rate classes and rates for a rate-effective period of up to three years and that maintaining the existing rate class is appropriate.

F. Investigatory Dockets

Staff's Position

564. Staff states that if its proposed 6:01 p.m. to 9:00 p.m. TOU window is rejected by the Commission, the Commission should then open an investigatory docket to examine Sierra's optional residential TOU schedules. (Ex. 326 at 7.) Staff is unsure whether a general rate case is the best way to examine TOU rate structures, given the level of depth of the topic and the fact that numerous other topics need to be addressed in a general rate case. (*Id.* at 7.) Staff states that an investigatory docket would allow additional interested parties a more in-depth analysis of TOU structures. (*Id.* at 7-8.) Staff states that, even if its proposed TOU window is accepted, it is still likely that further adjustments to TOU structures will be needed, and the best way to do that would be outside of a general rate case so that both Sierra and Nevada Power's TOU structures can be examined simultaneously. (*Id.* at 8.)

565. Staff also recommends the Commission order Sierra-E to investigate and determine whether a new customer class is warranted, and if so, order Sierra-E to implement a tiered rate structure for the consumption of energy for the residential customer class. (Ex. 328 at 30.) Staff states that this is necessary because the current residential class is not homogenous, as some customers in that class are consuming significantly more energy than others. (*Id.* at 30.)

Staff is concerned that when some residential customers use much more (or less) energy than most other customers, the result is the majority not being charged appropriately. (*Id.* at 31.)

566. Staff therefore argues that Sierra-E should be required to analyze whether a new customer class is warranted, and report back to the Commission when it files its next general rate case. (*Id.*) Staff also argues that, because there is a significant chance the high-use residential customers are not paying their appropriate share, that a tiered rate structure should be implemented until Sierra-E can present the results of said analysis. (*Id.*) Staff notes that Nevada Power, an affiliate of Sierra, already has more than one residential customer class – Residential and Large Residential. (*Id.* at 32.) Staff proposes to constrain the second-tier rate to be close to the first tier, as a rate in the second tier that is too high could inhibit Sierra's ability to achieve its revenue requirement for its current residential customer class. (*Id.*)

Sierra's Rebuttal

567. Sierra states that when the fixed BSC is set at levels that reflect fixed costs, and the corresponding volumetric charge reflects usage-varying costs, the potential intra-class subsidies between customer types are limited. (Ex. 283 at 13.)

568. Sierra states that it completed an analysis of its residential class in response to Staff's recommendation regarding the creation of a new residential rate schedule for high-usage customers. (*Id.* at 17.) Sierra divided the existing rate schedule into the standard D-1 customer class, along with a class deemed LD-1, which contained three-phase residential customers. (*Id.* at 18.) Sierra found that creating a new residential rate class could provide a benefit to large residential customers, but the overall effective rate for remaining residential customers would increase. (*Id.*)

569. Sierra states that it identified 380 large residential customers out of 239,000 total residential customers, which means that there simply are not enough large residential customers to have significant impact on the standard residential BSC. (*Id.* at 19.)

570. Sierra also disagrees with Staff's recommendation to implement tiered rates until Sierra can present a more thorough analysis of its residential class. (*Id.* at 20.) Staff states that it would take a significant amount of time to implement such a structure, and that it would not be able to be completed by October 1, 2024. (*Id.* at 21.) Sierra states that it has attempted to do tiered rates in the past, but they were removed due to customer unpopularity and inequities between customer classes. (*Id.*) Sierra also states that tiered rate structures have the potential to harm low-income customers, and Sierra doubts that a tiered rate structure will create a strong price signal for higher-energy users. (*Id.* at 23.)

571. Sierra maintains that its proposed BSC should be implemented for the entire residential rate class and that a new large residential rate class is not necessary. (*Id.* at 24.) Sierra states that the overall effective rate for this new class would be lower, while the costs for the remaining residential customers would be minimally impacted. (*Id.*)

Commission Discussion and Findings

572. The Commission declines to adopt Staff's recommendation to open any investigatory dockets with respect to TOU rates and a large residential rate class. The first request with respect to TOU rates is moot as the Commission is adopting Staff's recommendation regarding the time-period modification. With regard to establishing a large residential rate class, Sierra has provided evidence in rebuttal that such a class would be relatively small and of minimal impact on D-1 rates. Nevertheless, the Commission directs Sierra to evaluate establishing a large residential rate class in its next general rate case filing and

provide either a proposal to establish such a class or discussion and support in testimony as to why doing so is unnecessary.

573. The Commission is also interested in evaluating potential low-income rates for residential customers. Frequently, these customers have the least ability to change their usage and the Commission recognizes this burden. Accordingly, the Commission directs Sierra to also evaluate establishing a low-income rate class in its next general rate case filing and provide either a proposal to establish such a class or discussion and support in testimony as to why doing so is unnecessary.

G. Interclass Rate Rebalancing ("IRR")

Sierra's Position

574. Sierra calculates the IRR as a part of Statement O, on the page labeled "subsidy calculation." (Ex. 274 at 8.) Sierra states that the IRR applies to all rate classes, including DOS customers at the otherwise applicable rate schedule. (Ex. 274 at Prest Ex.-Direct-3.)

SEA's Position

575. SEA states that the IRR should not be assessed on its newly-proposed DOS-T customer, regardless of whether it is assigned a new schedule number. (Ex. 702 at 7.) SEA states that because the customer is only paying for minor Rule 9 charges, requiring it to fund rate mitigation at the equivalent as bundled service customers is not necessary nor reasonable. (*Id.* at 7.)

576. SEA states that Sierra is already proposing to increase Rule 9 facilities reimbursement charges by 30 percent, while also proposing to increase the BSC for this class by 390 percent, with an additional IRR of approximately $1,973,536 on top of those two other charges. (*Id.* at 7-8.) SEA states that the net effect of these charges is an overall rate increase for

Rule 9 facilities of 980 percent, which SEA states would have major financial implications on the affected customer if approved. (*Id.* at 8.)

577. SEA states that Sierra erred by assigning all schedule GS-3T distribution-related costs to the BSC, which is only meant to recover customer service and meter costs. (*Id.*) SEA states that because the schedule DOS GS-3T customer owns and pays for its own meter, there is a question as to whether the customer should pay the same BSC as the bundled schedule GS-3T rate class. (*Id.* at 8-9.) SEA further states that DOS customers also pay for metering and customer-service-related costs under the OATT, and the purpose of the BSC is duplicative of that OATT service. (*Id.* at 9.)

578. SEA states that the parameters of NRS 704B prevent Sierra from levying an IRR charge on NRS 704B customers because the IRR rate must be tied to services that are being furnished by the utility. (*Id.* at 11.) SEA states that Sierra's proposal would result in NRS 704B customers paying for services, such as energy, generation, and transmission services, that are not necessary for their provider of new electric resources to serve their loads, which is inconsistent with NRS 704B. (*Id.* at 12.)

579. SEA states that the Commission can address the IRR inconsistency by limiting the IRR for 704B customers to the distribution component of the IRR charged to the otherwise applicable rate schedules. (Ex. 702 at 12.) SEA recommends pro-rating the IRR assessed to the otherwise applicable rate schedule based on the proportion of that schedule's revenue attributable to each of the functional service categories. (*Id.* at 12.) SEA states that only the proportional amount of the IRR associated with distribution services would be assessed to DOS customers. (*Id.*) SEA states that this approach would still maintain the IRR, and involve only minor changes

to the existing model, while limiting the amount paid by NRS 704B customers to the distribution services they are receiving. (*Id.* 12-13.)

Peppermill's Position

580. Peppermill states that Sierra is over-allocating the IRR revenue to DOS customers. (Ex. 1100 at 3.) Peppermill states that the proposed IRR revenue is the primary driver in the large revenue increases proposed for DOS customers. (*Id.* at 3.) Peppermill states that Sierra is proposing a 235-percent increase in DOS rates. (*Id.*)

581. Peppermill is concerned that Sierra is basing its IRR for DOS customers on a bundled subsidy rate, inclusive of transmission, generation, and distribution costs. (*Id.*) Peppermill states that Sierra's proposal shifts generation and transmission costs of bundled customers onto DOS customers, while DOS customers should only be responsible for a distribution revenue requirement share of the total subsidy. (*Id.*) Peppermill states that it sees a wide disparity between various cost models and class revenues presented by Sierra. (*Id.*)

582. Peppermill states that the Commission should limit the IRR revenues paid by DOS customers to a pro rata share based on distribution revenue requirement, meaning that the DOS IRR revenue proposed by Sierra needs to be adjusted to remove the transmission and generation related amounts. (*Id.*) Peppermill notes that the Commission has previously ruled against a similar proposal from Sierra in Docket No. 19-06002. (*Id.* at 4.)

Walmart's Position

583. Walmart states that along with Sierra's proposed caps to increases at zero percent for residential classes and five percent for all other classes, it is also proposing a floor below the system increase to ensure all classes partially contribute to the increased revenue requirement regardless of cost-of-service study results. (Ex. 601 at 9.)

584. Walmart states that including subsidies in rates is problematic because it sends inaccurate price signals for all customers in the RS class. (*Id.* at 10.) Walmart states that, per Sierra's marginal cost study ("MCS"), several different rate schedules are impacted inequitably by the inclusion of these subsidies. (*Id.* at 11.)

585. Walmart states that if the Commission approves Sierra's proposed revenue requirement and Sierra's MCS, Walmart does not oppose Sierra's revenue allocation. (*Id.* at 12.) Walmart argues, however, that if the Commission approves a lower revenue requirement for Sierra, the Commission should apply half of the reduction only to customer classes that are proposed to pay subsidies to other classes through the IRR, and then apply the other half of the reduction on a pro rata basis to all customer classes. (*Id.* at 12.)

Sierra's Rebuttal

586. Sierra states that there are two shortfalls that make up the main reasons why Sierra has proposed its IRR. (Ex. 283 at 33.) Sierra states that the first shortfall is caused by the IS-2 subsidy (the rates for which are set in a separate docket), and the difference between the IS-2 set rate and the IS-2 cost-based levels is spread to the remaining Sierra customers. (*Id.* at 33.) Sierra states that the second shortfall is caused by Sierra's proposed cap of zero percent above system increase for residential customers, and five percent above the system increase for the remaining classes in reconciliation. (*Id.*) Sierra states that these two shortfalls are calculated based on each class's cost of service, but the policy decision of not setting cost-based rates is ultimately made by the Commission. (*Id.*)

587. Sierra states that Peppermill and SEA's arguments ignore the fact that the IRR rate is not reflective of a specific cost to Sierra and should not be broken down by the different services that it provides or that customers use. (*Id.* at 34.) Sierra argues that the IRR rate for all

customers is a mix of Commission and legislatively mandated policy decisions to set rates away from cost-based levels. (*Id.*)

588. Sierra argues that the IRR is not an attempt to force DOS customers to pay for generation and transmission costs because the IRR is not a cost-based rate but rather a policy decision to limit rate increases for certain classes, the calculations for which are outside of the functionalized revenue requirement. (*Id.*) Sierra states that limiting DOS customers' contribution to this policy decision creates inequity, and that the Commission has previously ordered DOS customers to pay the IRR. (*Id.* at 34-35.)

Commission Discussion and Findings

589. The Commission finds that the IRR is applicable to all rate classes. The Commission finds that all customers pay this rate based on their otherwise applicable rate class. The IRR is a rate design construct that serves to implement just and reasonable rates by allocating revenue imbalances to all rate classes. In Sierra's case, there is a two-part IRR. The first is a function of the IS-2 subsidy, and the second part arises from use of caps and floors in determining the final rate class revenues for rate design. These caps and floors are calculated based upon each rate class's total contribution to revenue requirement, and are not a function of a specific allocation of distribution, transmission, or generation revenue requirements or what service is being taken by what rate class. The methodology for calculating the IRR is transparent and fair.

590. In Docket No. 22-06014, no second-part IRR was calculated as no caps or floors were applied to the class revenue requirements. This is not the case in the instant Docket, so there are increases for the IRR that appear larger than if there had been an existing second part from the prior rate case. Caps and floors are addressed in a separate section of this order, as are

the rate class revenue allocations and Statement O. However, it is important to note that the IRRs in the rate design being adopted by the Commission in this order are significantly lower than what was requested by Sierra in its filing due to the Commission's removal of the energy component and in part using the modified ECS rather than the MCS.

591. The Commission declines to adopt Wal-Mart's proposal to apply half of any reduction to customers that are proposed to pay subsidies. As stated before, the IRR is not a result of any specific adjustment, and it would create additional rate class distortions if the proposal were attempted.

H. NEM Cost of Service

Sierra's Position

592. Sierra states that its NEM cost of service amount is derived in conjunction with the ECS and MCS, with costs from both COSSs contained in Ex. Bohrman-Cert-2, Ex. Nieto-Cert-2 Table 1, and Ex. Nieto-Cert-3 Table 1, respectively. (Ex. 277 at Bohrman-Cert-2; Ex. 273 at Ex. Nieto-Cert-1; Ex. 273 at Nieto-Cert-2.) Sierra states that its preferred Statement O also provides the NEM cost of service amount. (Ex. 274 at Prest-Direct-3.) Sierra provides further analyses on the NEM cost of service in the other Statement Os it prepared for this Docket. (Ex. 275 at Ex. Prest-Cert-4; Ex. 275 at Prest-Cert-5; Ex. 275 at Prest-Cert-6; Ex. 275 at Prest-Cert-7; Ex. 275 at Ex. Prest-Cert-8.)

593. Sierra provides that rates for NEM customers are not based upon their separate cost of service characteristics, but rather upon rates developed from the combination of these customers and the corresponding full-requirement customers. (Ex. 232 at 20.) Sierra states that the revenue differences from what NEM customers actually pay compared to their cost-based

results is contained in Statement O, and that difference is approximately $8.3 million ($7.8 million of which is for residential single-family NEM). (*Id.* at 20.)

594. Sierra states that it estimated the impact of these effective rates for NEM customers by reviewing usage data, with a focus on the energy delivered to NEM customers after monthly netting is applied. (*Id.* at 15.) Sierra states that NEM customers use on average about 349 kWh, roughly half of the monthly usage of a typical residential customer. (*Id.*) Sierra states that the average bill experienced by NEM customers was $48 in 2022, $54 in 2023, and is forecasted to be $51 in 2024, which includes the full proposed general rate case increase and forecasted BTER and DEAA rate decrease. (*Id.*)

SEIA's Position

595. SEIA states that Sierra's MCS is fundamentally flawed as it pertains to NEM customers and that the flaw renders moot the MCS's results for NEM customers. (Ex. 900 at 3.) SEIA states that the result of Sierra's MCS is predicated on several unsupported assumptions that Sierra makes early in the MCS process. (*Id.* at 8.) SEIA states that the imputed load profiles used by Sierra are not accurate in terms of how power flows across Sierra's assets and how NEM customers use the grid during high-load hours, while also failing to reflect the benefits of exported energy from NEM systems that power NEM customers' neighbors' loads. (*Id.*)

596. SEIA states that there are additional flaws in Sierra's MCS, including errors in meter cost installation expenses, and poorly supported customer accounts and service expenses that contain arbitrary assumptions. (*Id.* at 39.)

597. SEIA argues that when these assumptions and errors are corrected and updated based on per-customer information for residential, single-family NEM customers, post solar-cost

reduction from NEM customers using Sierra's cost responsibility methodology finds that solar reduces cost responsibility by 35 percent, despite no inclusion of any emission costs. (*Id.* at 82.)

598. SEIA argues that solar plus storage ("S+S") systems can further lower the cost of service by 70 percent. (*Id.* at 89.) SEIA argues that this percentage is a larger bill reduction that a NEM customer would receive on a flat rate and in line with the reduction received on a TOU rate. (*Id.*) SEIA argues that installing solar reduces the cost responsibility of NEM customers by 35 percent. (*Id.* at 82.)

599. SEIA states that NEM customers consume 24 percent to 38 percent more energy than non-NEM customers, and NEM customers' monthly peak demand is 20 percent to 33 percent higher than that of non-NEM customers. (*Id.* at 76.) SEIA states that while usage between the two classes varies, the two classes have similar monthly load profiles throughout the year. (*Id.* at 77.) SEIA states that when NEM customers add solar, the quantity of delivered energy falls substantially, as does the class share of peak usage. (*Id.* at 78.) SEIA states that the energy NEM customers export to the grid is critical to include because it properly accounts for received energy as a benefit to the system. (*Id.*) SEIA argues that solar generation substantially reduces the need for customers to consume from the grid during hours which have a high chance of incurring costs. (*Id.* at 81.)

600. SEIA states that installing solar reduces the cost responsibility of NEM customers by 35 percent, although that number does not include the social benefits of reducing greenhouse gas emissions, reducing pollutants, and the benefits of meeting policy considerations enacted by the State of Nevada. (*Id.* at 82.) SEIA notes that bills fall 56 percent to 58 percent after installing solar as well. (*Id.* at 83.) SEIA cites to an Environmental Protection Agency ("EPA") study that suggests the social cost of carbon is roughly $210/metric ton, meaning that each kWh of NEM

generation is worth approximately $0.10/kWH, while purchase of generation of coal would be worth $0.24/kWh. (*Id.* at 84-85.) SEIA also argues that solar generation brings economic development to Nevada, with 126 solar companies in operation in the state, which collectively have invested more than $12.2 billion since 2016. (*Id.* at 85.)

Sierra's Rebuttal

601. Sierra states that SEIA overstates the benefit of NEM customers sending energy back onto the grid and that SEIA's proposed imputed load profiles would double count NEM system energy production. (Ex. 285 at 27-28.) Sierra states that this flawed proposal from SEIA incorporates additional assumed benefit to the system beyond the credits that these customers currently receive for energy sent back to the grid. (*Id.*)

602. Sierra argues, regarding NEM meter costs, that the overhead cost components are not added to the cost of the meter used in the MCS and in Sierra's proposed rate design. (*Id.* at 34.) Sierra argues that installation time for a NEM meter exceeds the time to install a regular meter, and travel time for a meter technician is longer than that of the typical linesman who is often onsite already performing construction activities. (*Id.* at 35-36.) Sierra adds that NEM meter costs are collected through the BSC and not rates, and setting the NEM meter investment cost equal to that of the non-NEM would not change the proposed BSC of $45.30. (*Id.* at 39.)

603. Sierra argues that its customer accounting and customer service costs are based on Sierra's 2022 Customer Weighting Factor Study ("CWFS"), which is necessary for the calculation of each customer class's marginal customer cost that informs the cost basis for each class's BSC. (*Id.* at 40.) Sierra notes that NEM customers usually have more billing issues than normal customers, as a review of their consumption and generation is more labor intensive and includes the factoring-in of a number of exceptions not accounted for by Sierra's automated

billing process. (*Id.* at 44.) Sierra argues that if the automated billing process misses a data stream for whatever reason, it requires Sierra employees to manually pull the bill for review and potentially send out a field crew to investigate the issue in question. (*Id.*)

604. Sierra states that it has seen an increased number of NEM customers, an increased number of rate-counts and riders, and an increased number of NEM offerings in recent years. (*Id.* at 46.) Sierra states that its Customer Apps department and Customer Information Services department both work with the internal billing system and work in conjunction with one another, and therefore it is reasonable for those departments to use the same methodology to allocate costs. (*Id.* at 46-47.)

605. Sierra argues that for its Solar, Wind, and Water Renewable department, the allocation of expenses is based on the percentage of NEM applications in each rate group. (*Id.* at 47.) Sierra states that any incomplete applications were allocated to non-NEM customer groups, and any projects in the interconnection queue process waiting for net metering were allocated to the NEM customer class. (*Id.*) Sierra states that it cannot use customer counts as an estimate for customer cost allocations because it incorrectly allocates costs to customers who do not actually cause those costs. (*Id.* at 47-48.)

606. Sierra concludes by stating that the opportunity to do the correct analysis of determining each class's contribution to total generation costs is lost when the revenue from the BTER is excluded in the cost-allocation exercise. (Ex. 282 at 17.)

Commission Discussion and Findings

607. The Commission declines to change the methodology for calculating any potential NEM cost-of-service differences in the instant docket. The Commission shares some of the concerns identified by SEIA, and these are in part why the Commission is not approving the

MCS. Sierra's own testimony demonstrates the differences in the calculations between iterations of Statement O, including the one utilizing Staff's COSS. Including energy in the COSS exacerbates these differences. Nevertheless, the Commission acknowledges that there are some differences in the actual costs to service a NEM customer with respect to meters and customer service.

608. The Commission finds that the Nevada Legislature has mandated that there be one combined rate for customer classes for those participating and not participating in NEM, and Sierra has complied with the calculation of this single rate in its rate design for D-1, DM-1 and GS-1 rate classes.

I. Electric Vehicle Rate Rider ("EVRR") Discount Period

Staff's Position

609. Staff recommends moving the current EVRR schedule, currently set from 10:01 p.m. to 8:00 a.m. to 12:01 a.m. to 8:00 a.m. (Ex. 326 at 8.) Staff notes that this 12:01 a.m. to 8:00 a.m. window was approved by the Commission for Nevada Power in Docket No. 23-06007, and that this new window would align with lower marginal costs. (*Id.* at 8.)

Sierra's Rebuttal

610. Sierra recommends that the Commission accept Staff's proposal and joins in Staff's recommendation, as it would align the EVRR window with Nevada Power's. (Ex. 285 at 20.)

Commission Discussion and Findings

611. The Commission agrees with Staff and Sierra's proposal to shift the EVRR window to the time frame from 10:01 p.m. to 8:00 a.m. to a new window of 12:01 a.m. to 8:00 a.m.

J. Class Cost of Service ("COSS") – Sierra-E

Sierra's Position

612. Sierra states that it has conducted two versions of the MCS study for this Docket. (Ex. 272 at 2.) Sierra states that the first MCS study relies on the output of Sierra's simulation of company-wide generation dispatch, referred to as the joint dispatch ("JD") model. (*Id.*) Sierra states that the second MCS study satisfies a Commission directive from Sierra's previous general rate case, which required Sierra to file an MCS that simulates a hypothetical dispatch scenario. (*Id.* at 3.) Sierra explains that this scenario assumes that Sierra is only able to rely on northern Nevada's generation resources when determining economic dispatch of resources, and a separate reconciliation of energy and generation, which Sierra refers to as the standalone dispatch ("SAD") model. (*Id.*)

613. Sierra further provides that one purpose of an MCS is to measure how Sierra incurs costs when meeting load, reliability standards, and policy to accurately estimate the marginal costs of serving each customer class. (Ex. 272 at 4.) Sierra adds that another purpose of an MCS is that it helps identify the share of the class revenue target that needs to be recovered on a fixed basis by the appropriate rate components. (*Id.* at 4.) Sierra states that both of these functions help Sierra to design rates. (*Id.*) Sierra argues that marginal cost rates can help reduce electricity bills of the average customer, as the customer can add load in off-peak hours at a fraction of the cost that the customer would face if per-kWh or per-kW charges reflected the full functional embedded revenue requirement. (*Id.* at 7.)

614. Sierra states that it is the Equi-Proportional Marginal Cost ("EPMC") allocation to reconcile MCS results with each function's revenue requirement. (*Id.* at 29.) Sierra states that

each functional marginal cost revenue is reconciled to the corresponding function's revenue requirement using the EPMC. (*Id.*)

615. Sierra argues that its chosen MCS is most suitable to this general rate case because it employs sound methods that are common in the industry. (*Id.* at 46.) Sierra states that its MCS develops hourly cost information and differentials across classes that greatly help inform rate design, which also provides valuable information for setting TOU rates and non-TOU rates. (*Id.*) Sierra recommends that the Commission use the long-standing Sierra MCS practices as the basis to continue evaluating any required rate changes in this general rate case. (*Id.*) Sierra also endorses a joint dispatch approach for estimating marginal generation and energy costs, as using an MCS that employs the standalone approach does not treat all customers equitably. (*Id.*)

616. Sierra provides updates to the components of its MCS in its certification testimony, including updates to customer sales, customer counts, MECs, hourly marginal cost responsibility factors, cost of capital, construction costs, inputs to the T&D regression, variables to control for economic recessions, line extension facilities, Statement N, wage changes, account balances, meter additions, and the renewable marginal contribution value. (Ex. 273 at 3-5.) Sierra states that these updates to its MCS produce a total marginal cost revenue across all customer classes of $1,114 million, an increase of 3.2 percent from its direct filing. (*Id.* at 6.)

617. Sierra states that the class revenue was also affected by its updates to the MCS, including a 2.8-percent increase to marginal unit cost for the D-1 rate class, and a 3.4-percent increase for the DM-1 class. (*Id.* at 8.) Sierra states that the largest annual marginal cost revenue increase was for D-1 NEM and DM-1 NEM classes, at 21.1 percent and 29.6 percent,

respectively. (*Id.*) Sierra states that the total marginal cost per kWh at certification is 12.45 c/kWh. (*Id.*)

Marginal Cost Study ("MCS") vs. Embedded Cost Study ("ECS")

618. Sierra provides that the hourly marginal cost factors, or allocators, are used to assign transmission, primary distribution, generation, and energy costs to customer classes and TOU periods in a way that accurately reflects cost causation of use on the grid. (Ex. 226 at 2.) Sierra states that transmission and demand costs are allocated using the probability of peak ("POP") cost responsibility factors, generation capacity costs are allocated using forecasted hourly loss of load probabilities ("LOLPs"), and energy costs are allocated using hourly MECs. (*Id.* at 2-3.)

619. Sierra states that hourly cost responsibility factors are implemented in the MCS and ECS in the same manner as previous Sierra general rate cases. (*Id.* at 4.) Sierra states that the objective of the hourly cost responsibility factors is to establish the relative contribution that each customer class makes to the system's marginal energy, generation, transmission, and distribution costs. (*Id.* at 5.) Sierra provides that the resulting hourly cost responsibility factors are load-weighted and aggregated to each TOU class. (*Id.*) Sierra states that the classes with the largest proportion of total sales during the highest cost periods are responsible for the highest relative proportion of costs. (*Id.*)

620. Sierra states that its ECS was performed in three steps – functionalization, classification, and allocation, with the underlying principle being to classify revenue requirement in functional categories as either customer, demand, or variable, and then Sierra allocates costs to those customer classes. (Ex. 276 at 7.) Sierra states that its distribution components that were previously functionalized as either metering, customer accounting, customer service, or facility

categories are now classified as customer related. (*Id.* at 13.) Sierra states that primary demand, high-voltage distribution ("HVD") demand, transmission demand and generation demand are classified as demand costs, with generation variable costs classified as variable costs. (*Id.*) Sierra states that its allocation factors are consistent with those developed for the MCS. (*Id.* at 14.)

621. Sierra proposes to use an MCS in this case in lieu of an ECS for the purpose of allocating revenue requirement to all customer classes, as well as for the development of rate components and temporally differentiated rates, while noting that its rate design proposal reflects a jointly dispatched system. (Ex. 276 at 4.) Sierra states that an MCS utilities Sierra's cost of providing the next connection of a customer, adding the kW of generation, HVD, primary distribution capacity, and serving the next kWh of energy to the grid. (*Id.* at 6.) Sierra states that the MCS then builds the cost-to-serve information to a point where those costs can meaningfully inform the designation of rates for customer classes. (*Id.*) Sierra states that an MCS is Sierra's preferred methodology to inform rate design because it is a forward-looking study that provides for a more useful result that can be used to provide economically efficient and accurate price signals. (*Id.*)

622. Sierra states that the total distribution, transmission, and generation revenue will remain the same between the MCS and ECS, but there are differences in how those functions are spread to customer classes and how they are spread across the more granular rate components applicable to all customers in a given class. (*Id.* at 17.) Sierra states that its ECS suggests a monthly cost-based BSC with embedded distribution costs in the amount of $45.24 for a full-requirements D-1 customer. (*Id.* at 18.) Sierra states that the value is higher for D-1 NEM customers, with a cost-based BSC of $66.92 per customer, and when the two classes are combined, the result is a cost-based BSC of $46.11 for all residential single-family customers.

(*Id.*) Sierra states that this is a reason why it is not recommending that the Commission utilize the ECS for rate design in this proceeding. (*Id.*)

Staff's Position

623. Staff recommends that the Commission order Sierra-E to use Attachment ML-2, which is a summary of the allocations in Staff's COSS for Sierra-E. (Ex. 328 at 21, Attachment MIL-2.) Staff argues that energy should be removed from the reconciliation process, consumption should be used as an allocation factor, a stand-alone dispatch ("SAD") scenario should be used, and that Staff's line-loss calculations are more appropriate. (*Id.* at 21.)

624. Staff states that it is inappropriate for Sierra-E to include energy costs and recovery of those costs in a general rate case because those costs are handled in separate proceedings. (*Id.* at 5.) Staff states that even though a flat rate could lead to inequities among customer classes, NAC 704.032 requires the BTER to be flat. (*Id.* at 6.) Staff argues that it is inappropriate to reallocate a cost component that is outside the scope of that specific cost. (*Id.*) Staff also notes that the Commission has excluded energy revenue from reconciliation calculations previously in Docket No. 22-06014. (*Id.* at 10.)

625. Staff states that there are three types of allocators in all COSSs for electric utilities: customer count, energy consumption based on kWh consumed, and demand. (*Id.*) Staff states that Sierra's COSS model is flawed because it only uses the demand allocation methodology. (*Id.* at 11.) Staff states that appropriate weight needs to be given to hours that are not peak hours, and Sierra-E's COSS costs are mostly placed on peak hours. (*Id.* at 12.) Staff agrees that peak hours should be weighted more than other hours, but Sierra-E is not currently putting any meaningful weight onto non-peak hours, which leads to a flawed COSS. (*Id.* at 13.)

626. Staff states that Sierra-E's sole reliance on demand allocators results in almost all costs being placed on a few hours of the year, which results in a COSS that indicates Sierra-E is only incurring costs when usage is at its peak. (*Id.*) Staff states that its COSS model applies higher weight to peak hours and applies a relative weight calculation to all other hours, which results in all hours being weighted based on each customer class's use in that hour relative to the total consumption. (*Id.* at 14.) Staff maintains that cost allocations should reflect the reality of who is using the system at each hour, and Staff's COSS model reflects that reality. (*Id.*) Staff notes that it uses Sierra-E's system load factor for weighting consumption and demand. (*Id.*) Staff states that it uses 77 percent Sierra-E system load factor as the share of the consumption allocator, and the remaining 23 percent is set as the share of the demand-related allocator. (Ex. 327 at 4.)

627. Staff states that Sierra was directed in Docket No. 22-06014 to provide a COSS based on JD and SAD scenarios. (Ex. 328 at 15.) Staff states that Sierra elected to use the JD scenario, which Staff disagrees with. (*Id.* at 15.) Staff argues that the use of the Loss of Load Probability ("LoLP") and Marginal Energy Costs ("MECs") should be based on the SAD scenario because Sierra-E's and Nevada Power's rates are not unified. (*Id.* at 15-16.) Additionally, Sierra-E's customer load profiles that are used to reflect cost causation in the COSS remain the same. (*Id.* at 16.) Staff states that Sierra-E's customers are still responsible for the costs of Sierra-E's power supply resources under the JD scenario. (*Id.*) Staff notes that, most importantly, transfer payments under the JD scenario place Sierra-E and Nevada Power back in the position that they would have been in had they dispatched resources in a SAD scenario. (*Id.*) Staff states that until the JD scenario is modified to include compensation for capacity costs of

generating units or a scenario arises where rates are designed for a single entity, Staff does not support the use of the JD in a COSS. (*Id.* at 18-19.)

628. Staff also disagrees with Sierra-E's line-loss calculation approach because it is unclear what method(s) Sierra-E is using to determine its line-loss calculation. (Ex. 327 at 4.) Staff states that there are ambiguities in Sierra-E's written and verbal communications that hinder staff's comprehension of Sierra-E's approach. (*Id.* at 5.) Staff states that Sierra-E's line-loss calculations result in higher allocations than would otherwise occur, and as a result, the Commission should use Staff's methodology to calculate line loss. (Ex. 328 at 20.)

NNIEU's Position

629. NNIEU supports Sierra's use of an MCS as the methodology for calculating revenue requirement allocations. (Ex. 800 at 4.) NNIEU argues that this methodology is well-established because it has been accepted by the Commission since 1981. (*Id.* at 4.)

630. NNIEU recommends that the Commission reject any modifications to Sierra's MCS and reject the "hybrid ECS" methodology as both alternatives are inferior to the current MCS. (*Id.* at 5.)

631. NNIEU states that because Nevada Power and Sierra dispatch power jointly, any allocation that assumes a SAD is inconsistent with actual cost causation. (*Id.*) NNIEU further states that requiring Sierra to separately allocate generation and energy cost is inconsistent with actual cost causation, as Sierra uses both owned generation and purchased power to meet demand on a least-cost basis. (*Id.*) NNIEU states that the "hybrid ECS" alternative is a more egregious departure from customer class cost causation, as it requires the use of standalone distribution and excludes 47 percent of the revenue requirement from the allocation process entirely. (*Id.*)

632. NNIEU argues that both alternatives create significant subsidies ($14.7 million to modify the MCS and $22.7 million to use the hybrid ECS model) benefiting the residential customer class at the expense of the other classes, primarily the GS-3 class. (*Id.* at 8.)

Walmart's Position

633. Walmart states that if the Commission approves Sierra's proposed revenue requirement and an embedded cost study, the Commission should set rates at cost per the COSS results, notwithstanding any IS-2 subsidy impacts. (Ex. 601 at 12.)

Sierra's Rebuttal

634. Sierra argues that Staff has not provided any additional justification to exclude energy from the COSS, and Sierra further notes that it is not seeking to recover energy costs in the current general rate case. (Ex. 285 at 22.) Sierra argues that to develop cost-based rates and to appropriately allocate Sierra's revenue requirement, Sierra must use a COSS that reflects the relative class cost differentials including all components of the service that is provided to customers. (*Id.* at 22-23.)

635. Sierra argues that evaluating the impact of allocating costs using either SAD or JD on Sierra's customer usage profiles is irrelevant because the purpose of COSSs is to find the right modeling scenario for cost allocation, which has to be consistent with the way that the system is operated and planned to meet demands. (Ex. 282 at 7.)

636. Sierra states that its line-loss calculations are more appropriate to use in a COSS than Staff's because Staff's annual average loss factor reflects a constant percentage across all energy for individual classes, while Sierra's approach better reflects the impact to the system when loads are highest and provides a more accurate representation of how losses occur on the system. (Ex. 281 at 2.) Sierra argues that Staff's line-loss calculations cannot be applied to

Sierra's cost-of-service model, as each method should only be applied to the distinct models for which they were developed. (*Id.* at 2.)

637. Sierra states that its methodology is based on the National Economic Research Associates, Inc. ("NERA") marginal costing methodology and attempts to model line losses by voltage level across all hours of the year. (*Id.* at 2-3.) Sierra argues that Staff's proposal does not account for the impact of the hourly variations in losses that occur when loads fluctuate on the system, but instead applies an even percentage adjustment to all hours of the year. (*Id.* at 3.)

638. Sierra states that, overall, Staff's allocation model cannot be accurately used for rate design in this case. (Ex. 283 at 40.) Sierra states that it ran Staff's allocation model through Statement O without energy, and it resulted in large increases to commercial classes as compared to Sierra's proposal. (*Id.* at 41-42.) Sierra notes that Staff has proposed similar allocation models in Nevada Power's 2023 general rate case. (*Id.* at 42.) Sierra is also concerned with the allocation to the lighting classes, streetlights ("SL") and outdoor lighting schedule ("OLS"), because Staff's model reduces the revenue requirement for those classes by 53 percent, but that reduction in revenue is not carried through to the lighting information in Statement O where the costs are split by lamp type. (*Id.* at 43.) Sierra argues that there is a subsequent disconnect between the final class responsibility results and the revenue that the lighting classes will actually collect. (*Id.*)

639. Sierra is also concerned about how TOU period definitions affect allocation, as Staff's TOU proposals appear to contradict one another. (*Id.* at 44.) Sierra states that Staff is proposing to remove seasonal variation in the TOU periods, which is different from other Staff testimony that recommends moving the optional residential summer on-peak period from the 3:01 p.m. to 9:00 p.m. window to a 6:01 p.m. to 9:00 p.m. window. (*Id.*) Sierra goes on to argue

that removing seasonal variation in TOU periods would be a large change from Sierra's proposed rate that goes beyond the normal change in rate design without more notice to affected customers and the parties in this docket. (*Id.*)

640. Sierra states that another concern it has is that information appears to be missing from Staff's model, mainly the cost data related to critical peak pricing ("CPP") TOU period and additional meter costs ("AMC"). (*Id.* at 46.) Sierra states that the CPP TOU period reflects the highest-cost hours to serve customers throughout the year, and these costs are an important piece of Sierra's optional rate schedule offerings. (*Id.*) Sierra states that this information is necessary to calculate prices for the optional OD-1-CPP, OD-1-CPP-DDP, ODM-1-CPP, and ODM-1-CPP-DDP rate classes, with the AMC information being likewise necessary to calculate this rate for Sierra's commercial classes. (*Id.*)

641. Sierra therefore recommends that the Commission reject Staff's allocation model, and requests that the Commission direct Staff to, in the future, submit proposed cost-of-service models adequate to be used in rate design. (*Id.* at 40.)

Commission Discussion and Findings

642. The Commission does not approve Sierra's MCS as presented in this docket. While Sierra has continued to present its MCS and preferred methodology including energy and joint dispatch, the underlying bases that prompted the Commission to reject these in the past have not changed. The Commission finds that including energy skews the resulting BTGR rates that are being set here to recover costs which are not energy costs. Using a MEC to influence base tariff general rate revenue, and then removing the MEC, can lead to what appears to be recovery of an energy component in the BTGR when the BTER is less than the MEC or under-recovery of the BTGR when the BTER is higher than the MEC. Using the MEC to

somehow attempt to manipulate an energy price signal in the BTGR that is ultimately paid by a separate flat rate is inappropriate. Likewise, using joint dispatch assumptions in the COSS is not correct when considering that the two service territories have separate rate structures, and the joint-dispatch reconciliation process effectively puts each utility in the same place as if it had been dispatched separately. In addition, the joint-dispatch reconciliation adjustments are made through deferred energy accounting and ultimately become part of the BTER.

643. The Commission is also concerned with the demand allocation methodology and line losses used by Sierra as discussed in Staff's testimony. To be clear, Sierra should use actual data to the extent available in completing its next COSS.

644. The Commission finds that Staff's COSS has been designed to allow for both simplicity of understanding and use, and transparency. Staff's COSS allows for varying inputs as desired by the user of the model, consistently applied. The Commission finds compelling, however, Sierra's concerns identified in Exhibit 284 about the timing of implementing Staff's COSS in the instant docket and accordingly does not approve its use.

645. The Commission orders Sierra to meet with Staff to attempt to identify common ground and reach a consensus on Staff's model COSS. The Commission also orders Staff to provide its model and instructions to all other parties to this proceeding and to hold an informal workshop within 150 days of the date of the issuance of this order so as to discuss the model with any interested parties. The Commission additionally orders Sierra to file a COSS and Statement O consistent with Staff's model in future general rate case filings. Sierra may file other COSS as it would like, but at least one must be provided using Staff's model.

MCS vs. ECS

646. The Commission approves Sierra's ECS filing for use in the instant docket. However, in doing so, due to the marginal aspects of the calculation in the ECS, the Commission recognizes that the ECS is not a traditional ECS. The Commission finds that the ECS COSS submitted by Sierra is significantly affected by marginal components. Sierra discusses in its direct testimony how different methodologies exist and are prescribed by the National Association of Regulatory Utility Commissioners ("NARUC") in classifying customer- and demand-related costs for an ECS. (Ex. 276 at 11.) Sierra goes on to state that its plant accounting system cannot do the calculations as described by NARUC and that "the Company chose to allocate the shared facilities using the demand related plant data from the Company's marginal transmission and distribution unit demand costs." (*Id.* at 11.) Thus, the ECS is informed by marginal inputs.

647. The Commission encourages Sierra to perform calculations in the manner that NARUC prescribes them. The Commission finds that this will provide a true embedded cost-of-service analysis when an ECS is filed in a future proceeding.

648. The Commission rejects the use of the MCS for establishing rates in this case. The Commission finds that the MCS relies on a number of estimates and assumptions in performing its calculations. (Ex. 272 at Figure Nieto-Direct-2.) The Commissions is concerned that there are so many manipulated calculations in the MCS that it is rendered unreliable. The Commission must rely on the most accurate information, even though the ECS submitted by Sierra has flaws, it is not as flawed as the MCS.

K. Class Cost of Service – Sierra-G

Sierra's Position

649. Sierra-G states that its rate design proposal includes an embedded cost of service study that follows the Commission's previous directives, as well as supporting Sierra-G's rate design as set forth in Statement O. (Ex. 112 at 3.)

Staff's Position

650. Staff is concerned about the use of demand, more specifically the sole use of demand, for certain allocations of costs in Sierra-G's COSS. (Ex. 328 at 36.) Staff states that it has advocated for certain costs to be allocated solely on demand in the past, but it no longer does now. (*Id.* at 36.) Staff is concerned about Sierra calculating its demand allocation based on 3 peak days of the test year, as Sierra-G's facilities are used around the clock all year. (*Id.*) For this reason, Staff suggests that a throughput or commodity factor should be included in the demand allocation. (*Id.* at 37.) Staff recommends a 50/50 weight for throughput and demand should be used as a first step in including a throughput allocation. (*Id.*) Staff states that if the Commission does not wish to use a 50/50 weight between throughput and demand, the Commission could place a different weight on the throughput portion, for example 33.3 percent throughput and 66.7 percent demand weights. (*Id.*)

651. Staff argues that these calculations are tested and auditable, developed in and through Sierra's COSS model, built on Sierra's data, and accepted in diverse analytical communities. (Ex. 327 at 9.) Staff recommends that the Commission should find the concepts and calculations underpinning Staff's proposal for Sierra-G's cost of service are reliable and valid. (*Id.* at 10.)

Sierra's Rebuttal

652. Sierra argues that Staff's testimony lacks justification to deviate from current methodology, and only claims that there is an increased need to allocate demand-related costs

using throughput volumes. (Ex. 280 at 6.) Sierra notes that Staff wants to know how Sierra-G's facilities are utilized and how they should be accounted for in allocating fixed demand-related costs. (*Id.* at 6.) Sierra argues that Staff has not provided an explanation of what has materially changed in gas distribution to warrant Staff's change from its prior position and Sierra's proposed methodology. (*Id.*)

653. Sierra argues that there is a non-intuitive result from Staff's recommendation for the interruptible max-per-therm for the non-firm Transportation class, which is an increase to the Large Commercial Natural Gas ("LCNG") volumetric rate. (*Id.*) Sierra states that the Interruptible Transportation tariff pegs the max-per-therm interruptible rate to the LCNG volumetric rate, which means that if the LCNG rate increases, the interruptible max-per-therm rate increases as well. (*Id.* at 6-7.) Sierra states that Staff's recommendation shifts demand costs from Transportation to LCNG results in a decline in Firm Transportation rates. (*Id.* at 7.)

654. Sierra states that, typically, customers receive a discount for accepting interruptible service, so an interruptible rate above a firm rate is a non-intuitive result. (*Id.* at 7.)

Commission Discussion and Findings

655. The Commission approves Sierra-G's COSS and rate design in Statement O, with the exception of the BSC of the residential customer class, which will be set at $16.00 rather than $18.00 to mitigate rate impacts and provide gradualism for customers. The Commission finds that the COSS is an embedded cost study as completed in the past and consistently applied in the rate design. The Commission declines to implement Staff's recommendation with respect to implementing a throughput or commodity factor at this time but instructs Sierra to include a COSS in its next gas general rate case that reflects Staff's recommendation of a 50/50 allocator for the Commission to consider.

L. Statement O

Sierra's Position

656. Sierra states that Statement O is a summary of the technical aspects and implementations of rate calculations that supports Sierra's rate design proposal, which is a 9.68 percent increase to revenue requirement from present rate levels. (Ex. 274 at 2-3.) Sierra states that it has set forth and described the development of proposed rates for all classes of customers, including fully bundled service and DOS customers. (*Id.* at 6.) Sierra provides five additional versions of Statement O, with and without Sierra's recommended rate cap and floor, which demonstrate the rate design results through the implementation of different COSS's and modeling assumptions. (*Id.* at 3.) Sierra states that its preferred version of Statement O is shown in Ex. 274 at Prest-Direct-3, as it contains Sierra's preferred MCS, which uses joint dispatch hourly cost responsibility factors, with generation and energy revenue reconciled together to reach the proposed revenue requirement. (*Id.* at 5.)

657. Sierra states that its Statement O consists of 22 pages and six workpapers that summarize the overall revenue allocation and rate design results including impacts by class. (*Id.* at 7.) Sierra states that its Statement O sets both a cap and floor to the revenue requirement increase by class and employs full cost-based rates in the BSC, unless the movement results in a decline to the BSC. (*Id.* at 17-18.) Sierra states that the impact of these caps and floors is a combined single family residential shortfall of $34 million, 23 percent of which comes from D-1 NEM customers. (*Id.* at 20.) Sierra states that, overall, the average increase for fully bundled non-residential customers (other than IS-2 customers) is 7.93 percent, with the average increase for customers billed under optional classes not included in reconciliation is 55 percent. (*Id.*)

658. Sierra notes that DOS customer class revenue increases 325 percent under its proposal, and that the rates for DOS customers are not constrained by the cap/floor proposal because DOS customer rates are set to the same level as their fully bundled OARS. (*Id.* at 22.) Sierra states that this is done because there is essentially no difference in the cost to serve DOS customers and their OARS counterparts when it comes to Sierra's distribution system. (*Id.*)

659. Sierra states that it updated Statement O in its certification filing to reflect updates to inputs such as: unbundled revenue requirement in Statement IS-2, billing determinants and present rate revenue, cost study information from both the MCS and ECS, and updates to the Rule 9 facilities study and customer-specific facilities information for transmission-level customers. (Ex. 275 at 2-3.) Sierra also states that present Base Tariff General Rate ("BTGR") and BTER revenue decreased by $63.9 million from the direct filing. (*Id.* at 3.) Sierra notes that these updates resulted in an overall increase to the proposed revenue requirement of $1.4 million to a total of $96.1 million, which also increases the total requested BTGR and BTER revenue to 10.50 percent. (*Id.* at 4.)

660. Sierra states that it is maintaining the same rate design proposals as in its direct filing with a 0 percent cap above system increase cap to the D-1 class, which results in the combined D-1 and D-1 NEM will increase by 10.5 percent as opposed to 9.68 percent in Sierra's direct filing. (*Id.* at 7.) Sierra states that resulting residential shortfall remains at $34 million, 26 percent of which is attributable to D-1 NEM customers. (*Id.*) Sierra notes that the IS-2 subsidy decreases from $14.3 million in its direct filing to $9.3 million at certification, due to the shift in customers and removal of the resulting adjustment. (*Id.*)

661. Sierra proposes the implementation of a zero percent capped class revenue mechanism for the D-1 and DM-1 customer classes, the implementation of a five percent capped

class revenue mechanism for all other fully bundled customer classes, and the implementation of a 9.68 percent floor class revenue mechanism for all customer classes. (Ex. 232 at 18.) Sierra updates the 9.68 percent floor class revenue mechanism for all customer classes to 10 percent in its certification testimony. (Ex. 278 at 5.)

662. Sierra states that the cap implements a limit on the highest change that these classes will experience, with any required revenue above the capped level shifted to other classes. (*Id.* at 19.) The floor implements a limit on the lowest change that a class will experience, designed so that these classes will contribute more towards the proposed increase in system revenue requirement. (*Id.*)

663. Sierra states that its proposed zero percent cap for residential customers will mitigate the rate impact of the cost-based result. (*Id.*) Sierra states that without the cap, the rate increase for residential customers would be much higher than 9.68. (*Id.* at 21.)

NNIEU's Position

664. NNIEU states that Sierra has not provided specific policies or extenuating circumstances which support the size of its proposed residential customer class subsidy (23.3 percent). (Ex. 800 at 9.) NNIEU states that Sierra's differing proposed rate caps for residential customers and other classes is inequitable, and Sierra has provided no explanation of why different caps for customer classes are appropriate. (*Id.* at 9.) NNIEU also states that subsidizing residential customers at the expense of industrial customers sends false price signals to both classes, contributing to inefficient energy decisions. (*Id.*) NNIEU states that Sierra's proposed revenue requirement increase (10.5 percent) is excessive and does not reasonably balance the need to avoid rate shock and progress toward cost-based rates. (*Id.*)

665. NNIEU therefore proposes a 5-percent cap and a -10-percent floor for all customer classes. (*Id.*) NNIEU states that the application of this cap and floor reduces the potential residential increase from 23.3 percent to approximately 15.5 percent. (*Id.* at 10.)

Staff's Position

666. Staff states that, when an MCS is used, such as in the instant Docket, one must look at Statement Os to determine rates and calculations. (Ex. 328 at 6.) Staff states however that there isn't a clean or easy way to compare revenue requirements when generation and energy are combined, as they are in the instant Docket. (*Id.* at 6.) Staff states that when generation and energy are combined, one cannot reduce the generation revenue requirement by a calculated BTER reduction to determine generation revenue requirement. (*Id.* at 6-7.) Staff states that it cannot easily compare where rates are designed for each class and compare these figures to what are included in other versions of Statement O. (*Id.* at 7.) Staff states that the best place in Statement O to get a general idea of what impact COSS has on each class is in the "Rev Comp B" tab, and use the column labeled "BTGR Revenue Proposed," which is even more problematic in the versions of Statement O where a customer class revenue cap is used (such as in the instant docket.) (*Id.*)

667. Staff states that it is important to note that the results shown in the Rev Comp B tab of Statement O for BTGR are not only byproducts of the COSS, but also include any policy proposal being made, which include Sierra-E's proposed zero percent above the average cap for residential classes and five percent cap for the remaining customer classes. (*Id.*) Staff argues that one cannot look at the BTGR revenue proposed figures and assume that the figures represent only results of the MCS. (*Id.* at 8.)

668. Staff argues that Sierra's Statement Os, contained in Exhibit 275 Prest-Cert-3 and Prest-Cert-4, are not appropriate models to compare cost-study impacts on classes due to the proposed capping methodology. (*Id.*) Staff states that to make any Statement O compared to other ones, the proposed revenue caps and floors must be removed. (*Id.*) Staff states that once that is done, a reasonable comparison could be made for the embedded revenue requirement between customer classes when the comparison involves an MCS. (*Id.*) Staff argues that Sierra-E did not provide a complete set of Statement Os that correspond to the various COSSs included in the filing. (*Id.* at 9.)

Sierra's Rebuttal

669. Sierra states that its generation and energy revenue are grouped together because there is a strong tie between those costs and because the MECs are not reflective of the current BTER revenue. (Ex. 283 at 48-49.) Sierra notes that while it is harder to compare models that combine generation and energy revenue, combining those two revenues is not a flaw with Statement O. (*Id.* at 49.)

670. Sierra states that Staff Exhibits 328 ML-3 and ML-4 appropriately remove Sierra's proposed cap and floor from Exhibit 275 at Prest-Cert-3 and Prest-Cert-4 and produces expected similar results to Exhibit 275 at Prest-Cert-6 and Ex. Prest-Cert-7 (Sierra's Statement Os). (*Id.* at 49-50.) Sierra notes that while it did not provide every iteration of Statement O conceivable, it provided two Statement O models for each of the three cost studies presented in this case. (*Id.* at 50.) Sierra states that it attempted to make its Statement O models easier to read by including toggles that switch between reconciling generation and energy either combined or separately, as well as including energy costs. (*Id.* at 50-51.)

671. Sierra recommends that the Commission employ a cap, setting the residential class at an increase no higher than the system average increase and setting a floor where no customer class would receive a decrease. (Ex. 286 at 11.) Sierra recommends that for classes other than the residential class, the Commission should set a cap at an increase no higher than five percent above the system average increase. (*Id.* at 11.)

Commission Discussion and Findings

Statement O - General

672. The Commission approves Exhibit 275 Prest-Cert-5 as the Statement O for use in setting rates. This is the iteration of Statement O that is the ECS with marginal allocators, standalone dispatch, energy excluded, with rate caps and a rate floor. The Commission finds that this version of Statement O is the best fit in allocating revenue requirement to Sierra's rate classes to calculate just and reasonable rates. The Commission has discussed elsewhere in this order its positions on the MCS, the inclusion of energy, standalone versus joint dispatch, and rate caps and floors. Exhibit 275 at Prest Cert 5 addresses the Commission's concerns with Sierra's preferred Statement O using the MCS.

673. The Commission notes that in Exhibit 284 at Table Prest-Rebuttal-9, the comparison of Statement O models, the Staff model figures included in the table did not reflect rate caps as the other two examples, Prest-Cert-3 (Preferred Statement O) and Prest-Cert-5. Using the data from the workpapers filed with the rebuttal testimony, the table is updated below for informational purposes only. It should also be noted that if Staff's COSS were used with the same rate caps and a rate floor, the IRR appears to flip such that the calculated subsidy is to commercial and industrial classes.

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Class	Prest-Cert-3		Prest-Cert-5		Staff Model		Staff Model Capped	
	$	**% Change**	**$**	**% Change**	**$**	**% Change**	**$**	**% Change**
D-1	323,898	10.50%	308,796	13.76%	300,844	10.83%	303,156	11.68%
DM-1	65,536	10.50%	60,104	11.20%	57,097	5.64%	57,520	6.42%
GS-1	85,671	12.49%	75,897	13.01%	76,738	14.26%	77,298	15.09%
GS-2S	154,365	11.63%	132,942	11.16%	136,533	14.16%	136,231	13.91%
GS-2P	5,013	6.32%	4,433	11.90%	5,054	27.60%	4,433	11.90%
GS-2T	1,622	15.50%	1,308	12.86%	1,537	32.61%	1,308	12.86%
GS-2S TOU	46,667	13.33%	39,694	11.07%	40,235	12.58%	40,497	13.32%
GS-2P TOU	5,501	1.67%	4,921	7.70%	5,562	21.74%	5,134	12.37%
GS-2T TOU	1,234	12.78%	970	6.15%	931	1.88%	936	2.43%
GS-3S	38,869	10.68%	33,359	10.23%	34,855	15.17%	34,235	13.12%
GS-3P	43,600	6.02%	38,599	10.11%	41,130	17.33%	39,619	13.02%
GS-3T	152,941	1.66%	131,261	7.00%	134,006	9.24%	134,672	9.78%
GS-4	2,095	0.50%	1,811	5.64%	1,822	6.28%	1,831	6.82%
IS-1	5,760	15.50%	5,007	10.41%	4,340	-4.29%	4,371	-3.60%
IS-2	7,883	0.00%	4,693	0.00%	4,693	0.00%	4,693	0.00%
WP	880	15.50%	775	14.66%	723	6.98%	728	7.69%
SL	5,236	15.50%	4,851	8.90%	3,577	-19.70%	3,612	-18.91%
OLS	1,566	0.50%	1,875	22.97%	1,138	-25.39%	1,148	-24.70%
OGS-1	3,253	11.98%	2,862	12.28%	3,000	17.69%	2,930	14.95%
OGS-2S	32,885	11.35%	28,818	12.41%	29,979	16.94%	29,157	13.73%
OGS-2P	312	15.50%	254	11.83%	294	29.20%	254	11.83%
OGS-2T	-		-		-		-	

674. The Commission appreciates Sierra's addition of toggles in the various Statement O versions. The toggles have improved the ability to evaluate the various iterations. However, the Commission notes that in doing so for Sierra's preferred Statement O, in removing energy, the worksheet tabs that calculate the increase from present rate revenue do not update the present rate revenue to exclude energy and thus appear to have rate reductions in excess of 60 percent. The Commission further finds that, when the present rate revenues are adjusted to remove the BTER and EDRR, the results are unusual in that multiple rate classes see rate increases in excess of 100 percent. Accordingly, for future implementation, the Commission requests that all tab calculations be fully updated if a toggle is changed.

Cap and Floor Adjustments

675. The Commission approves the rate caps as proposed by Sierra, with residential D-1 and DM-1 classes capped at an increase no higher than the system average increase, all other fully bundled classes capped at an increase of no higher than five percent above the system average increase, and setting a floor where no fully-bundled customer would receive a decrease. The Commission recognizes that generally it is preferable to not establish rate caps or rate floors, but in this case, it is necessary to mitigate rate shock. The Commission finds that implementing rate caps and rate floors in conjunction with the approved ECS version of Statement O also minimizes any calculated subsidy that is recovered through the IRR as compared to the MCS.

M. Transmission and Distribution ("T&D") Marginal Costs

Sierra's Position

676. Sierra states that for this Docket, a 25-year regression method was utilized to calculate T&D marginal costs. (Ex. 260 at 3.) Sierra states that this method was most recently

used in Nevada Power's recent general rate case in 2023, with a similar regression-based methodology being used in every Nevada Power and Sierra general rate case from 2010 to 2020. (*Id.* at 3.)

677. Sierra states that the use of a regression analysis allows it to estimate the historical relationship between capacity additions and peak load using data across different economic cycles. (*Id.*) Sierra states that this relationship can be impacted during recessions during which both T&D investment and peak loads may diverge from what would be expected during normal economic conditions. (*Id.*)

678. Sierra states that it uses a 25-year regression period in this Docket because of Staff and BCP concerns in a previous general rate case, where Sierra used a ten-year regression period. (*Id.* at 4.) Sierra states that these concerns were centered on the idea that a ten-year period is not forward-looking, which undermines the principle of a marginal COSS not being based on historical averages. (*Id.*) Sierra states that it has in turn modified its regression period to not only be longer, but also to include a mix of both historical and forecast years. (*Id.* at 5.) Sierra states that a 25-year regression method is conceptually sound to obtain a long-term view of marginal costs. (*Id.*)

NCARE's Position

679. NCARE is concerned about the assumptions Sierra uses when Sierra calculates hourly marginal costs. (Ex. 1001 at 12.) NCARE states that Sierra's cost calculation reflects a 25-year regression period that is excessive, includes non-representative data, and contradicts testimony from other Sierra witnesses. (*Id.* at 12.) NCARE states that Sierra's inclusion of data from 2002 to calculate T&D costs extends farther into the past than is appropriate, which is especially problematic because the dataset from 2002 to 2007 shows robust growth, and then

from 2008 shows a more moderate growth, which results in a discontinuous data set. (*Id.* at 13.) NCARE states that this discrepancy presents a risk that previous trends that do not apply to today's landscape and results in a distortion of Sierra's calculations of the present relationship between demand and cost. (*Id.* at 15.) NCARE disagrees with Sierra's assertion that a 25-year regression period is warranted due to the long lifecycles of T&D infrastructure and the influence of evolving technologies, because the argument undercuts Sierra's position that T&D infrastructure often lasts longer than 25 years, which begs the question of why Sierra is not using an even longer timeline for calculating T&D costs. (*Id.*)

680. NCARE states that using a 15-year regression period is a more accurate representation of recent T&D costs, and the use of that shorter period results in an overall decrease to marginal costs. (*Id.* at 15-16.) NCARE therefore recommends that Sierra update its T&D marginal cost calculation to reflect a 15-year regression period. (*Id.* at 12.)

Sierra's Rebuttal

681. Sierra states that a 25-year regression period is better to use to calculate T&D marginal costs because the 25-year regression period is comprised of 22 historical years (2002-2023) and three years of forecasted projection, which is consistent with other information in the MCS. (Ex. 282 at 11.)

682. Sierra states that NCARE's arguments undermine the importance of economies of scale in T&D investment. (*Id.* at 11-12.) Sierra states that recognizing that economies of scale lead to lumpiness of investment, a 25-year period is in line with goals of the study because it allows finding a predictor of the typical, long-term marginal unit cost of investments as peak load grows. (*Id.* at 12.) Sierra disagrees with NCARE's assertion that unrepresentative data sets were used in its T&D marginal cost calculations because it is challenging to only rely on future

investments as long-term projections of capital plans, as they tend to be more uncertain over beyond the first 5 years. (*Id.* at 12-13.) Sierra states that NCARE's arguments for a 15-year regression period are undercut by the fact that historical peak demands for Sierra's T&D systems are not obviously trending downwards. (*Id.* at 13.)

Commission Discussion and Findings

683. The Commission agrees with Sierra's methodology to calculate transmission and distribution marginal costs where used. The Commission agrees with party positions that the 25-year regression period is more appropriate than the 10-year regression period that Sierra has provided historically. While the 25-year regression period has been approved for this rate case filing, the Commission agrees with party arguments that a similar methodology with a shortened 15-year timeframe including 12 historical years and three forecast years may be more representative of the transmission and distribution marginal costs. The 15-year period would also align the calculation to the recommended method found in NARUC's manual. The Commission directs Sierra to include a 15-year regression period in its transmission and distribution marginal costs analysis in addition to the 25-year and 10-year periods that Sierra currently submits in its next rate case filing if Sierra relies on these marginal costs for any part of its application.

VII. PAST DIRECTIVES

684. The Commission finds that Sierra met the directive in Paragraph 7 of the Order in Docket No. 22-06014 to establish a regulatory liability with carry charges at Sierra's authorized rate of return for any over-collection of revenues from the Schedule Online Temporary Rider ("ONTR") rate rider based upon the rate set.

685. The Commission finds that Sierra generally met the directive in Paragraph 9 of the Order in Docket No. 22-06014 to file in this general rate case a complete hybrid embedded cost of service study using stand-alone dispatch and using Staff's methodology with enough detail to allow for transparent review and vetting by the parties and Commission. The Commission finds that Sierra consulted with Staff in advance of filing this study regarding the preparation of the study.

686. The Commission finds that Sierra generally met the directive in Paragraph 10 of the Order in Docket No. 22-06014 to file in this general rate case a marginal cost of service study with generation and energy costs separately reconciled, and that energy costs were allocated on a stand-alone basis.

687. The Commission finds that Sierra generally met the directive in Paragraph 13 of the Order in Docket No. 22-06014 to file other cost of service studies, including combined generation and energy allocated using joint dispatch, and that Sierra provided detailed testimony supporting these studies.

688. The Commission finds that Sierra met the directive in Paragraph 14 of the Order in Docket No. 22-06014 to provide an update on the progress of developing a clean transition tariff and its appropriateness for development as a new tariff offering to the Commission by May 2023 in the investigatory docket opened pursuant to the Order in Docket No. 22-06014.

689. The Commission finds that Sierra met the directive in Paragraph 15 of the Order in Docket No. 22-06014 to meet with Staff regarding the listed potential solutions and other solutions either party may have regarding efficient ways to review Sierra's books and records. The Commission finds that within the three months following the issuance of the Order in

Docket No. 22-06014 that Sierra and staff met the directive to file reports with the Commission on the progress and solution from that/those meeting(s).

690. The Commissions finds that Sierra met the directive in Paragraph 16 of the Order in Docket No. 22-06014 to present any previously approved regulatory assets and liabilities sought for recovery in a future general rate case to be presented at their amortized values as of the anticipated rate-effective date of that general rate case application.

691. The Commission finds that Sierra met the directive in Paragraph 6 of the Order in Docket No. 23-06007 to, in advance of filing any general rate case, meet with Staff to discuss the information necessary to ensure all transmission customers are paying the appropriate cost share.

692. The Commission finds that Sierra met the directive in Paragraph 7 of the Order in Docket No. 23-06007 to, in advance of filing any general rate case, meet and confer with Staff to discuss the appropriate Federal Energy Regulatory Commission transmission allocator.

693. The Commission finds that Sierra met the directive in Paragraph 8 of the Order in Docket No. 23-06007 to include in any future general rate filings, provide details about its most recent Federal Energy Regulatory Commission rate case and provide an explanation of Sierra's plans for future rate-setting proceedings at the Federal Energy Regulatory Commission.

THEREFORE, it is ORDERED:

1. The Application of Sierra Pacific Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto, designated as Docket No. 24-02026, is granted in part as modified by this order.

2. The Application of Sierra Pacific Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of gas customers

and for relief properly related thereto, designated as Docket No. 24-02027, is granted in part as modified by this order.

Compliances

3. Sierra Pacific Power Company d/b/a NV Energy shall file the rates and supporting workpapers in the instant dockets, in executable form with formulas and links intact, within ten calendar days of the issuance of this order.

4. Sierra Pacific Power Company d/b/a NV Energy and the Regulatory Operations Staff shall coordinate on determining the appropriate depreciation expense and incorporate that adjustment into the revenue requirement of this general rate case, which shall be reflected in the rates to be provided pursuant to Ordering Paragraph 3 above.

5. Sierra Pacific Power Company d/b/a NV Energy shall remove IT costs from the list of projects contained in Ex. 312 at YA-1 and incorporate that adjustment into the revenue requirement of this general rate case and shall be reflected in the rates to be provided pursuant to Ordering Paragraph 3 above.

6. Sierra Pacific Power Company d/b/a NV Energy shall determine the amount of project costs specific to the Rainbow Bend 8-inch lateral to be removed from rate base as well as any related depreciation expense and incorporate that adjustment into the revenue requirement of this general rate case and resulting rates to be provided pursuant to Ordering Paragraph 3 above.

7. Sierra Pacific Power Company d/b/a NV Energy shall file the schedules supporting the adjustments to unprotected excess accumulated deferred income taxes in electronic executable form with all links and equations intact within five business days.

8. Sierra Pacific Power Company d/b/a NV Energy, the Regulatory Operations Staff, and the Bureau of Consumer Protection shall have informal discussions to address what

information should be expected to be provided by Sierra Pacific Power Company to satisfy the Regulatory Operations Staff's and the Bureau of Consumer Protection's investigatory and audit responsibilities regarding affiliate charges. Those parties are further ordered to, within six months of the issuance of this Order, provide an informational report as a compliance to this docket to apprise the Commission of any progress or impasse that the parties encounter.

Directives

9. Sierra Pacific Power Company d/b/a NV Energy shall file a tariff modification request to incorporate the changes agreed to by the parties. Sierra Pacific Power Company d/b/a NV Energy must also work with the Regulatory Operations Staff, the Bureau of Consumer Protection, and other intervenors to include application termination metrics into existing or future NEM application reporting.

10. Sierra Pacific Power Company d/b/a NV Energy shall meet with the Regulatory Operations Staff in an effort to reach a consensus regarding the use of the Regulatory Operations Staff's model cost-of-service study. The Commission also directs Sierra Pacific Power Company d/b/a NV Energy to file a cost-of-service study consistent with the model used by the Regulatory Operations Staff in future general rate case filings.

11. The Regulatory Operations Staff shall provide its model and instructions to all other parties to this proceeding and hold an informal workshop within 150 days of the date of this order to discuss the model with any interested parties.

12. Sierra Pacific Power Company d/b/a NV Energy shall evaluate the establishment of a large residential rate class in its next general rate case filing and provide either a proposal to establish such a class or discussion and support in testimony as to why it is unnecessary.

13. Sierra Pacific Power Company d/b/a NV Energy and Nevada Power Company d/b/a NV Energy shall review alternatives for incorporating the difference in wildfire risk and exposure between Sierra Pacific Power Company d/b/a NV Energy and Nevada Power Company d/b/a NV Energy into the excess liability premium allocation factors applied to the insurers in its excess liability program that include coverage for wildfire liability, with such alternatives presented to the Public Utilities Commission of Nevada in Nevada Power Company d/b/a NV Energy's or Sierra Pacific Power Company d/b/a NV Energy's next general rate case filing.

14. Sierra Pacific Power Company d/b/a NV Energy and Nevada Power Company d/b/a NV Energy shall file a cost-of-service study and Statement O consistent with the Regulatory Operations Staff's model in future general rate case filings. Sierra Pacific Power Company d/b/a NV Energy and Nevada Power Company d/b/a NV Energy may file other cost-of-service studies as they would like, but at least one must be provided using the Regulatory Operations Staff's model.

15. Sierra Pacific Power Company d/b/a NV Energy shall evaluate establishing a low-income rate class in their next general rate case filings and provide either a proposal to establish such a class or discussion and support in testimony as to why it is unnecessary.

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16. Sierra Pacific Power Company d/b/a NV Energy shall include a cost-of-service study in their next gas general rate cases that reflect the Regulatory Operations Staff's recommendation of a 50/50 allocator for its throughput allocation for the Commission of Nevada to consider.

By the Commission,

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HAYLEY WILLIAMSON, Chair

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TAMMY CORDOVA, Commissioner

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RANDY J. BROWN, Commissioner and Presiding Officer

Attest: ______________________________
TRISHA OSBORNE,
Assistant Commission Secretary

Dated: Carson City, Nevada

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(SEAL)