BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Annual Deferred Energy Accounting Adjustment Application of the Electric Division of Sierra Pacific Power Company d/b/a NV Energy for the 12-month period ending December 31, 2023, reset the Temporary Renewable Energy Development Charge, reset all components of the Renewable Energy Program Rate, reset the Base Energy Efficiency Program Rates, reset the Base Energy Efficiency Implementation Rates, reset the Energy Efficiency Program Amortization Rate, reset the Energy Efficiency Implementation Amortization Rate, and reset the Expanded Solar Access Program rate.	**Docket No. 24-03___**

VOLUME 2 OF 9

APPLICATION, DRAFT NOTICE AND EXHIBITS

APPLICATION

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APPLICATION

Sierra Pacific Power Company d/b/a NV Energy ("Sierra" or the "Company") respectfully submits this application (the "Application") pursuant to Sections 704.110(11)(c) and 704.187(3) of the Nevada Revised Statutes ("NRS"). The primary purpose of the Application is to satisfy the requirement of NRS § 704.110(11)(c) by providing a forum for the Public Utilities Commission of Nevada (the "Commission") to review the Company's fuel and purchased power transactions for the 12-month period ending December 31, 2023 (the "Deferral Period"). The Application also seeks the authority to reset several other rate elements.

The Application is based on the prepared direct testimony of 16 witnesses filed in support of the Application, the exhibits to the Application, and the appendices that accompany the Application.

I. <u>Summary of Application</u>

Because Sierra changes the electric division's Deferred Energy Accounting Adjustment ("DEAA") each quarter, this Application does not propose any DEAA changes. Instead, the Application provides a forum for Commission review of fuel and purchased power costs and financial transactions that were recorded during the Deferral Period.

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As of December 31, 2023, the adjusted cumulative balance in the Company's deferred energy account was $56,827,863. This balance has decreased by approximately $167 million during the Deferral Period due to lower fuel and purchased power costs combined with a deviation from the statutory DEAA recovery mechanism[1] that allowed the Company to provide rate relief to its customers during the summer months while still lowering the DEAA balance. This amount reflects the reasonable cost of fuel and purchased power transactions undertaken by Sierra to provide electric service to its customers. The Application demonstrates that these costs were prudently incurred and are reasonable and, consequently, requests a finding that the costs should be recovered. Exhibit D-1 shows the derivation of the cumulative balance.

The Application also requests authorization to reset the Temporary Renewable Energy Development ("TRED") charge, reset Renewable Energy Program Rates ("REPR"), reset the Base Energy Efficiency Program Rates ("Base EEPR"), reset the Base Energy Efficiency Implementation Rates ("Base EEIR"), reset the Energy Efficiency Program Amortization Rate ("Amortization EEPR"), reset the Energy Efficiency Implementation Amortization Rate ("Amortization EEIR"), and reset the Expanded Solar Program Costs ("ESPC") rate.

A. <u>The TRED, the REPR, the Energy Efficiency Rates and the ESPC Rate</u>

Sierra proposes to establish the following TRED charge and REPR.

Table 1

	Current – per kWh	Proposed – per kWh
TRED	$0.00072	$0.00032
REPR	$0.00177	$0.00089

Exhibit H shows the calculation of the updated TRED charge pursuant to Section 704.8898(3) of the Nevada Administrative Code ("NAC"). The TRED charge is based on the total funding required for the year that the charge will be in effect, which is October 1,

[1] See Order dated June 28, 2023, in Docket No. 23-05028.

2024, through September 30, 2025. Total TRED requirements are calculated by forecasting total receipts (including interest earned on the trust balance) and disbursements to the trust plus the minimum balance requirement less the projected balance at September 30, 2024. The funding requirement is then divided by historical sales for the rate effective period. Exhibit I shows the calculation of the proposed REPR. The TRED and REPR adjustments would become effective on October 1, 2024.

Exhibit J shows the Base EEPR and Base EEIR proposed by Sierra. Exhibit K shows the Amortization EEPR and Amortization EEIR proposed by Sierra.

Sierra updated its Base Tariff Energy Rate ("BTER") each quarter in 2023. Table 2 identifies each of the quarterly filings.

Table 2
Quarterly BTER

Quarterly BTER Adjustment	Test Period for Quarterly BTER Adjustment	Test Period Costs Previously Reviewed
Docket No. 23-02018	12 Months Ending December 31, 2022	Docket No. 23-03006 (1^{st}, 2^{nd}, 3^{rd}, 4^{th} Qtr. 2023)
Docket No. 23-05016	12 Months Ending March 31, 2023	Docket No. 23-03006 (2^{nd}, 3^{rd}, 4^{th} Qtr. 2023)
Docket No. 23-08009	12 Months Ending June 30, 2023	Docket No. 23-03006 (3^{rd} & 4^{th} Qtr. 2023)
Docket No. 23-11015	12 Months Ending September 30, 2023	Docket No. 23-03006 (4^{th} Qtr. 2023)

Sierra does not propose to change the BTER in this filing. Brian Ahlstedt describes the quarterly BTER adjustments in his testimony.

B. <u>EEIR Revenue Adjustment</u>

Consistent with the Commission's Order in Docket No. 13-04014 and the resulting modifications to NAC § 704.9523(4), which requires that Deferral Period EEIR base revenues collected be refunded if the Company earned rate of return exceeds its authorized rate of return. However, as shown in the Earned Rate of Return calculation in Exhibit F, sponsored by Jenny Naughton, Sierra did not exceed the authorized return, and therefore, is not required to refund the Base EEIR revenue received in 2023. Samantha Prest describes the EEIR revenue refund mechanism and the fact that the Company is not filing an Exhibit L with this Application in her testimony.

C. Witnesses Supporting the Application

Collectively, the prepared direct testimony of the Company's witnesses demonstrates that the Company (a) dispatched its generating units in an efficient and appropriate manner in light of the prevailing conditions; (b) procured fuel for its generating units in a prudent manner; (c) bought and sold power in a prudent manner; (d) optimized its fuel resources in an appropriate manner to capture value for the benefit of its customers by offsetting fuel and purchased power costs; and, (e) optimized its gas transportation capacity to capture value for the benefit of its customers by offsetting fuel and purchased power costs. In summary, the following witnesses' testimony filed in support of the application demonstrates that the fuel, transportation, and purchased power transactions during the Deferral Period were prudent and the attendant costs included in the deferred energy account balances are reasonable.

Jeffrey R. Bohrman, Director, Regulatory Pricing and Economic Analysis. Mr. Bohrman presents an overview of the filing. He also discusses how the procurement of energy and fuel is consistent with the approved Energy Supply Plans ("ESP") and ESP updates, and the processes that the Company has put in place to comply with the ESP and ESP updates in the Deferral Period and sponsors Technical Appendix 3. Additionally, he identifies compliance items the Company has satisfied in this filing. Finally, Mr. Bohrman provides a short conclusion and recommendation to the Commission.

Brian Ahlstedt, Senior Revenue Requirement and FERC Analyst. Mr. Ahlstedt supports the calculation of the TRED charge, the REPR, as well as the ESPC rate. Mr. Ahlstedt sponsors proposed tariffs, current tariffs and the calculation of rate impacts on the various rate classes. Mr. Ahlstedt also sponsors Exhibit A, Exhibit B, Exhibit D, Exhibit G, Exhibit H, Exhibit I and Exhibit N.

Ryan Atkins, Vice President, Resource Optimization. Mr. Atkins describes the Company's risk management and control policies governing the purchase and sale of energy products. Mr. Atkins also identifies the power and fuel transactions, and any financial transactions which occurred during the Deferral Period, all of which were made in accordance with strategies and policies that are established by the Risk Committee. Finally, Mr. Atkins describes how the Company's gas, power, and gas transportation resources are optimized for the benefit of our retail customers. Mr. Atkins supports Technical Appendix 1.

Catalin Adrian Cacuci, Treasurer. Mr. Cacuci summarizes the Companies' risk control strategies and describes the risk control organization and functions. Mr. Cacuci supports the prudence and reasonableness of recorded fuel and purchase power costs, concluding the transactions that resulted in fuel and purchased power costs recorded during the Deferral Period were conducted in accordance with the Company's corporate governance policies and procedures. Finally, Mr. Cacuci identifies relevant compliance items and reports the status of the Company's efforts to satisfy those directives. Mr. Cacuci supports Technical Appendices 2A, 2B and 2C, as well as Technical Appendix 6.

John Lescenski, Manager, Plant Engineering and Technical Services. Mr. Lescenski describes the generating units owned by Sierra that were available to serve its load and support optimization operations for the Deferral Period. He also provides information regarding the Net Capacity Factor and the Equivalent Availability Factor of each unit. Mr. Lescenski further discusses the availability and reliability of the generating fleet, including significant events that restricted the availability of the units. Finally, he discusses costs associated with wear and tear of generating units including a discussion on active Long Term Service Agreements for certain generating units. Mr. Lescenski supports Technical Appendix 5.

Saundra Massic, Director, Customer Contact. Ms. Massic's testimony describes the Expanded Solar Access Program ("ESAP") and supports the recovery of ESAP costs incurred in the Deferral Period.

Eugene T. Meehan, Special Consultant, National Economic Research Associates. Mr. Meehan examines the prudence of all non-renewable power transactions for terms of less than three years made by Sierra for delivery during the Deferral Period, concluding that the Company acted in a prudent manner and that the costs associated with purchased power transactions are reasonable.

Jenny Naughton Revenue Requirement and FERC Manager. Ms. Naughton supports the calculation of the rate of return and the earnings sharing calculation for Sierra. Additionally, Ms. Naughton supports the calculation of the Amortization EEIR and EEPR rates. Ms. Naughton also sponsors

Exhibit F, Exhibits K, K-1, and K-2, Exhibit M, Technical Appendix 4 and Technical Appendix 7.

Edgar Patino, Director of Contract Management and Special Programs. Mr. Patino’s testimony addresses: (a) long-term non-renewable power purchase agreements, pursuant to which the Company recorded costs during the Deferral Period; (b) renewable energy and portfolio energy credit purchase agreements, pursuant to which the Company recorded costs during Deferral Period; (c) NV GreenEnergy Rider agreements; and (d) portfolio energy credit replacement costs for several renewable power purchase agreements.

Damon Pettinari, Fuel and Purchase Power Manager. Mr. Pettinari sponsors Exhibit C, which reflects the Company’s financial statements, as well as Exhibits E-1 and E-2, which reflect the recorded costs of fuel and purchased power. Mr. Pettinari also explains the Companies’ Energy Imbalance Market (“EIM”) accounting procedures and protocols and describes and supports the Company’s methodology in allocating invoice activity related to the Joint Dispatch Agreement (“JDA”), EIM, and the calculation related to joint saving and transfer payments.

Samantha Prest, Pricing Specialist. Ms. Prest supports the proposed Base EEPR and Base EEIR in this proceeding. Ms. Prest calculates (a) the class and the total revenue requirements associated with the implementation of Energy Efficiency and Conservation (“EE&C”) programs, (b) the Base EEIR for each class designed to recover this revenue requirement, and (c) the Base EEPR by class designed to recover projected EE&C program costs. The calculation of the Base EEIR and EEPR can be found in Exhibit J, which is sponsored by Ms. Prest.

Ali Shiekh, Manager, Integrated Energy Services Delivery Operations. Mr. Sheikh supports the reasonableness of the energy efficiency programs ("EEP") costs that are requested for recovery in this case and explains that EEP costs recorded during the Deferral Period were necessarily incurred in connection with the delivery of EE&C programs and were reasonable under the circumstances. Mr. Sheikh also sponsors and presents Exhibit J-2, 2024 Forecast Demand Side Management program costs, which provides the Company's estimated program costs for EE&C programs for program year 2024. Exhibit J-2 provides the basis for calculating the Base EEPR and Base EEIR. Mr. Sheikh also supports Sierra's cumulative balance in Federal Energy Regulatory Commission Account No. 182.3 for the Deferral Period for the Solar Program, the Lower Income Solar Energy Program, the Wind Program, the Small and Large Energy Storage Programs, and the EV Demonstration Program. Finally, Mr. Sheikh sponsors Exhibit I-2.

Kurt G. Strunk, Director, National Economic Research Associates. Mr. Strunk assesses the reasonableness of the Company's physical natural gas commodity transactions for the Deferral Period. Mr. Strunk concludes that the Company's physical natural gas procurement costs are reasonable and prudent expenditures.

Vernon W. Taylor, Director, Trading Operations. Mr. Taylor describes and supports the Company's optimization of energy supply resources under the JDA for the Deferral Period. In addition, he describes and supports the Company's calculation of benefits from EIM transactions for the Deferral Period. Mr. Taylor also supports the Company's forward sales of wholesale electricity. Additionally, he describes and supports the economic dispatch of the Company's generating assets during the Deferral Period. Mr. Taylor describes and supports activities performed as part of the Company's compliance with Commission orders from previous dockets related to wear and tear costs. Finally, Mr. Taylor describes and supports the Company's portfolio optimization of participating resources through active participation in the California Independent System Operator ("CAISO") EIM for the Deferral Period.

Vincent Vitiello, Gas Supply Planning Lead. Mr. Vitiello supports the Company's portfolio of gas transportation assets and associated financial transactions that occurred during the Deferral Period.

Kim Whetzel, Director, Grid Operations and Reliability. Ms. Whetzel explains the procedures that the Company has in place to balance loads and resources and supports the prudence of those procedures. Ms. Whetzel discusses the Company's participation in the CAISO's EIM and the operational changes as a result of the EIM.

D. Exhibits and appendices supporting the Application

The witnesses sponsor the following, which support the Application:

Table 3

Exhibit	Description	Witness
Exhibit A	Proposed Tariffs	Mr. Ahlstedt
Exhibit B	Current Tariffs	Mr. Ahlstedt
Exhibit C	Balance Sheet and Income Statement	Mr. Pettinari
Exhibit D	Summary of Deferred Energy Accounts – Electric Department	Mr. Ahlstedt
Exhibit D-1	Calculation of Deferred Energy Balancing Account	Mr. Ahlstedt
Exhibit D-2	kWh Sales – Billed and Unbilled	Mr. Ahlstedt
Exhibit E-1	Purchased Fuel Costs	Mr. Pettinari
Exhibit E-2	Purchased Power Costs	Mr. Pettinari
Exhibit F	Earned Rate of Return	Ms. Naughton
Exhibit G	Present and Proposed Rate Revenue	Mr. Ahlstedt
Exhibit H	Calculation of TRED Charge	Mr. Ahlstedt
Exhibit I	Calculation of Renewable Energy Program Rate	Mr. Ahlstedt
Exhibit J	Calculation of Base EEPR and Base EEIR	Ms. Prest
Exhibit J-1	2024 Class-Specific Sales Forecast	Ms. Prest
Exhibit J-2	Forecast 2024 Demand Side Management Program Costs	Mr. Sheikh
Exhibit K	Calculations of Amortization EEPR and Amortization EEIR	Ms. Naughton
Exhibit K-1	Recorded Energy Efficiency and Conservation Program Costs	Ms. Naughton and Mr. Sheikh
Exhibit K-2	Accrued Energy Efficiency Implementation Rate Revenue	Ms. Naughton
Exhibit L	EEIR Adjustment Rate	N/A
Exhibit M	Regulatory Return and Earnings Sharing	Ms. Naughton
Exhibit N	Calculation of ESPC Rate	Mr. Ahlstedt

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In addition, seven appendices support the Application. Appendix 1 contains the minutes and presentations from Gas Hedging workshops. Mr. Atkins sponsors the material found in Appendix 1. Appendix 2 contains the Enterprise Risk Management and Control Policy, the Energy Risk Management and Control Policy, and the Credit Risk Management and Control Policy. Mr. Cacuci sponsors Appendix 2. Appendix 3 contains a list of ESP and ESP updates and orders that governed the Company's activities. Mr. Bohrman sponsors Appendix 3. Ms. Naughton sponsors Appendix 4, which contains the workpapers supporting the calculation of the Earned Rate of Return. Mr. Lescenski sponsors Appendix 5, which provides information regarding the Company's capitalization policy and long-term service agreements. Appendix 6 contains the Energy Risk Committee meeting minutes and presentations. Mr. Cacuci sponsors Appendix 6. Appendix 7 contains the modified regulatory return on equity calculation and earning sharing calculation. Ms. Naughton sponsors Appendix 7.

Finally, the Company is providing parties at the time of this filing information and data that is generally requested during the early stages of discovery to help facilitate the Commission's Regulatory Operations Staff's and the Bureau of Consumer Protection's review of the filing and streamline the discovery process.

The Application, prepared direct testimony, exhibits to the Application and appendices set forth all material facts upon which the Commission may base a decision granting the requested rate change and finding that recorded fuel and purchase power and financial transaction costs are reasonable and were prudently incurred.

II. <u>The Applicant</u>

Sierra is a Nevada corporation and wholly-owned subsidiary of NV Energy, Inc. Sierra is a public utility as defined in NRS § 704.020, and is subject to the jurisdiction of the Commission. Sierra has been authorized by the Commission to conduct its business within its certificated areas in Nevada pursuant to Certificates of Public Convenience and Necessity issued by the Commission. Sierra provides electric service to the public in portions of fourteen northern Nevada counties, including the communities of Carson City, Minden, Gardnerville, Reno, Sparks, and Elko. Sierra also owns and operates a certificated local distribution company engaged in the retail sale of natural gas to customers in the Reno-Sparks metropolitan area.

Sierra's primary business office is located at 6100 Neil Road in Reno, Nevada. All correspondence related to this Application should be served electronically upon the following address: regulatory@nvenergy.com. Hardcopy documents should be transmitted to Sierra's counsel as set forth below:

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III. <u>Statutes and Regulations Supporting the Requested Action</u>

Sierra makes this application pursuant to NRS §§ 704.061 to 704.068 (definitions and acts deemed to be a change in schedule), NRS §§ 704.110 (procedure for changing schedule), NRS § 704.187 (use of deferred accounting by certain electric utilities), and the regulations implementing those provisions, including, but not limited to: NAC § 703.115 (governing deviations from Commission regulations), NAC §§ 703.375 to 703.410 (public utility tariffs), NAC §§ 703.530 to 703.577 (pleadings), NAC § 703.710 (prepared testimony), NAC § 703.715 (documentary evidence), and NAC §§ 704.023 to 704.195 (deferred accounting by certain electric and natural gas utilities).

IV. <u>Adjustment Date and Proposed Amortization Period</u>

The adjustment date within the meaning of NAC § 704.024 for this Application is December 31, 2023. As Mr. Ahlstedt explains, the balance has been calculated in accordance with the NAC, including NAC § 704.045. Exhibit D-1 shows the monthly expenses and revenues, as well as the shortfall or surplus between costs and revenues. The exhibit also shows accumulated balances, adjustments and carrying charges.

V. Justification for the Proposed Rates and the DEAA Balance

A. The DEAA Balance

Pursuant to NRS § 704.187(1), Sierra uses deferred energy accounting to record all increases and decreases in its cost for purchased fuel and power. Each month, Sierra accumulates the difference between the cost of purchasing fuel and purchased power and fuel and purchased power revenues (i.e., BTER and DEAA revenue) pursuant to NAC § 704.075. Sierra calculates appropriate carrying charges on a monthly basis. Accordingly, the difference between costs and BTER revenue was calculated monthly and accumulated in the DEAA account.

1. Calculation of Deferral Period Costs

Sierra purchased fuel and power during the Deferral Period in furtherance of its statutory obligation to provide safe and reliable electric service to customers. All purchased fuel and power costs are recorded and accounted for by month. The monthly accounting of all purchased fuel transactions is set forth in Exhibit E-1. The monthly accounting of all purchased power costs by supplier is set forth in Exhibit E-2. The recording and accounting of the costs of all purchased fuel and power transactions during the Deferral Period are supported by the testimony of Mr. Pettinari. Sierra requests a finding that the costs recorded in the deferred energy account during the Deferral Period were prudently incurred and are reasonable.

2. Procurement and Risk Control Practices and the Reasonableness of Recorded Costs

Sierra procures physical natural gas and financial products pursuant to an ESP and ESP updates. Mr. Atkins describes and supports the procurement and resource optimization strategies pursuant to which Sierra made purchase and sale transactions that resulted in recorded costs during the Deferral Period. Mr. Atkins' prepared testimony demonstrates that

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Sierra's procurement and optimization activities resulted in just and reasonable costs. Mr. Atkins demonstrates that Sierra procured natural gas and coal in compliance with applicable policies. Similarly, Mr. Vitello demonstrates that the Company procured natural gas transportation services in compliance with the applicable energy supply plan policies. Together, these witnesses show that recorded fuel costs are just and reasonable.

Mr. Patino demonstrates Sierra's long-term non-renewable, renewable energy and portfolio energy credit purchases were prudent and that the costs associated with those purchases were just and reasonable. Mr. Bohrman discusses how the procurement of energy and fuel is consistent with the approved ESP and ESP updates, and the processes that the Company has put in place to comply with the ESP and ESP updates in the Deferral Period. Mr. Cacuci describes and supports the risk control measures in effect to ensure compliance with applicable ESP and ESP updates. Mr. Cacuci concludes that the Company's activities were consistent with applicable policies.

Sierra's witnesses, in short, demonstrate that the costs reflected in the deferred energy balance reflect the results of transactions that occurred in compliance with the governing ESP and ESP updates. Transactions occurred at prevailing market conditions and Sierra took reasonable and appropriate steps to optimize resources for the benefit of its retail customers.

In addition, Sierra retained Mr. Strunk to provide an independent assessment of Sierra's physical gas cost and procurement activities. Mr. Strunk concludes that Sierra's physical gas purchases and transactions were prudent. Sierra also retained Mr. Meehan to conduct an independent review of Sierra's power procurement activity and optimization efforts. Mr. Meehan concludes that Sierra's power procurement and optimization strategies were prudent, and Sierra used its generating resources in an appropriate and efficient manner to provide safe and reliable electric service to customers at just and reasonable rates. In summary, the independent analysis conducted by National Economic Research Associates corroborates the conclusions of Sierra's witnesses – namely, that the recorded balances in

Sierra's deferred energy accounts reflect the results of prudent transactions and are just and reasonable.

3. Calculation of Carrying Charges and Earned Rate of Return

NAC § 704.150 provides that the carrying charge to be applied to the deferred balances is calculated based on the Company's last authorized overall rate of return. Two adjustments are made to the carrying charge calculation. First, Sierra's authorized rate of return is grossed up to reflect the taxes payable on the equity component of the rate of return. Second, a deferred tax offset must be applied. Accordingly, the tax-effected rate of return is applied to the average monthly balance less accumulated deferred income taxes. Exhibit D-1 and Mr. Ahlstedt support the carrying charge calculations.

Sierra's balance sheet and income statements are provided as Exhibit C and supported by Mr. Pettinari. Sierra's jurisdictional earned rate of return for the Deferral Period is provided for in Exhibit F and supported by Ms. Naughton.

4. Justification for the Quarterly BTER Adjustments

During 2023, Sierra made four quarterly adjustment applications based on monthly costs. Table 2 provides the docket number for each quarterly adjustment, the applicable test period, and a reference to the dockets in which test period costs have been reviewed by the Commission. All of the recorded costs were either reviewed in Sierra's previous deferred energy cases, or are being presented for review in this case. None of the transactions that were reviewed in previous dockets were found to be imprudent. Mr. Ahlstedt addresses the quarterly BTER adjustments in his prepared direct testimony. Additionally, the Company filed an application in Docket No. 23-05029 seeking authorization to deviate from the statutory limits on the quarterly DEAA rate adjustments to provide rate relief to its customers during the summer months. Ms. Naughton addresses this deviation in her testimony.

B. Justification of the TRED Rate

NAC § 704.8897(4) provides that:

> [t]he costs incurred by a utility provider to initiate and maintain a TRED trust, including, without limitation, the cost of reserves advanced by the utility provider to the TRED trust, the taxes assessed on the utility provider for amounts related to the TRED trust and the fees charged by the trustee, must be considered expenses associated with the acquisition of purchased power, must be booked by the utility provider in FERC account 557 as an 'other expense' associated with purchasing power and may be recovered by the utility provider pursuant to the deferred energy accounting process set forth in NAC § 704.023 to § 704.195, inclusive.

Only one TRED-eligible renewable energy project is expected to deliver renewable energy or PCs to Sierra during the proposed rate effective period. Sierra has contracted with Solargenix Energy, LLC (now known as Nevada Solar One or "NSO"), to purchase a portion of the output of a concentrating solar thermal power plant. Under the current Commission approved agreements, Sierra receives 32 percent of the output of the facility, and Nevada Power Company receives 68 percent of the output of the facility.[2]

Based upon the expected costs associated with the NSO project as well as the related costs that the Company is directed to recover through the TRED charge pursuant to NAC § 704.8897(4), Mr. Ahlstedt calculates the proposed TRED charge in Exhibit H.

C. Justification of the REPR

Sections 701B.140 and 701B.495 of the NAC require Sierra to include in its annual deferred energy applications a Solar Program rate, a Wind Program rate, and a Water Program rate. These three rates, along with the Small Energy Storage Program, Large Energy Storage Program and Electric Vehicle Program rates, have been combined in the proposed REPR.

Consistent with the Commission's regulations, Sierra has calculated a two-part rate for the Solar, Wind, Water, Small Energy Storage, Large Energy Storage and Electric

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[2] *See* Docket Nos. 05-6027 and 05-6028.

Vehicle programs. Each of the applicable regulations calls for a prospective rate determined by dividing projected program costs by projected kilowatt hours ("kWh") for the calendar year. For consistency with NAC Chapter 701B Annual Plan filings and in light of statutory mandates,[3] the Company has been using projected kWh for the program year that runs from July 1 through June 30 in the denominator to calculate the prospective rate. The regulation additionally provides for a clearing rate, which is calculated by dividing the cumulative balance in the applicable subaccount of FERC Account No. 182.3 at the end of the deferred energy test period by the appropriate test period sales. To the extent necessary, the Company requests a deviation from NAC §§ 701B.140(a), 701B.495(a) and 701B.675(a), which require the use of projected kWh for the calendar year.

The calculation of rates for Solar, Wind, Water, Small Energy Storage, Large Energy Storage and Electric Vehicle programs is shown on Exhibit I, pages 1 and 2 of 3. Part (a) of each rate utilizes the projected program costs divided by projected sales for the program year July 1, 2024, through June 30, 2025, shown on Exhibit I, page 3 of 3. Part (b) divides the applicable regulatory asset balance (Account No. 182.3) by calendar year 2023 sales from Exhibit I-1. Mr. Sheikh supports the prudence of existing program balances as well as the future cost projections for the programs. The Company requests a deviation from NAC §§ 701B.140(a), 701B.495(a) and 701B.675(a), which require total program costs filed with the Annual Plan and instead it proposes the projected program costs as presented by Mr. Sheikh. The projected costs reflect the dollars Sierra believes will be spent in the program year based on history and estimated customer project completion rates and statutory limitations.

D. <u>Justification for the EEPR and EEIR Rates</u>

This portion of the Application is made pursuant to NRS § 704.785 and NAC §§ 703.535 and 704.9523. EE&C programs have a positive impact on the community Sierra serves, improving the quality of life, assisting customers in saving energy and money, and

[3] *See, e.g.,* NRS § 701B.005.

reducing or deferring the need for new generation, transmission and distribution facilities. The EEPRs provide for the recovery of the cost associated with delivering EE&C programs to customers. Those costs include, among other things, costs for labor, overhead, materials, incentives paid to customer, advertising, marketing, monitoring and program evaluation.

Consistent with NRS § 704.785 enacted by the 2009 Nevada Legislature, the EEIRs eliminate a financial disincentive associated with energy efficiency programs. Energy efficiency programs offer Sierra's customers the opportunity to conserve energy. By doing so, the Company's customers not only reduce their electric bills, but also reduce the overall, long-run cost of providing electric service. However, Sierra's successful EE&C deployment efforts also reduce the Company's sales and revenue.

Pursuant to NAC § 704.9523, the Company sets prospective base rates using projected program costs. In this Application, the Company uses its approved demand side management plan to establish projected program costs as presented by Mr. Sheikh. As shown on Exhibit J-2, Sierra anticipates spending a total of $15,879,503 on EE&C programs in 2024. The total approved budgeted amount shown in Exhibit J-2 to the filing of program costs and the calculated implementation revenue is allocated across classes using the percentage of total combined marginal costs of generation and energy from the Company's Marginal Cost of Service Study (Table 1, Page 1) approved in the most recent general rate case. Ms. Prest provides the detailed description of the methodology used to calculate the Base EEPR and Base EEIR.

Further, the Company requests permission to reset the Amortization EEIR and Amortization EEPR rates. These rates reflect program costs recorded between during the Deferral Period, and lost sales suffered by the Company during the same period. Mr. Sheikh supports the program cost expenditures, demonstrating that the program costs were prudently incurred and are reasonable. Ms. Naughton is responsible for calculating the Amortization EEPR and Amortization EEIR.

E. Justification for the ESPC Rate

This Company has calculated the ESPC rate consistent with Section 16 of the regulations adopted by the Commission in Docket No. 19-06028, as shown in Exhibit N. Carrying charges are recorded as described in the order from Docket No. 20-12003.[4] For that reason, costs are reflected for 2023 as Period 3 costs, and costs being amortized from January through September 2023 in current rates are reflected as Period 2 to properly calculate carrying charges. This illustration is similar to the balancing account treatment the Companies use for other programs' costs and recovery. This methodology ensures that any over or under collection is tracked and reclassified, as necessary. Page two of Exhibit N shows the test period sales for the 12 months ending December 31, 2023. The total is reflected on page one. The rate is calculated by dividing the cumulative balance for Period 2 by the total test period sales for all applicable customers, including Distribution Only Sales customers. Ms. Massic supports the prudency of the costs for the ESAP while Mr. Ahlstedt supports the calculation of the ESPC rate.

VI. Participation in the CAISO EIM

The EIM is a regional balancing energy market operated by the CAISO that optimizes generator dispatch every 15 and 5 minutes to satisfy imbalance energy needs while respecting reliability limits. The integration of variable energy resources, namely solar photovoltaic and wind generation, is enhanced by leveraging load and resource diversity across the seven state geographic footprint of the EIM. The Companies began participating in the EIM on December 1, 2015. The following witnesses address the Company's participation in the EIM: Ms. Whetzel, Mr. Lescenski, Mr. Pettinari, Mr. Taylor, Mr. Meehan and Mr. Strunk.

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[4] Docket No. 20-12003, August 11, 2021, Order at 104, paragraph 280.

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VII. Tariffs

Tariffs reflecting the proposed rates are set forth in Exhibit A**.** Tariffs reflecting current rates are set forth in Exhibit B. Mr. Ahlstedt supports the tariff changes.

VIII. Request for Confidential Treatment[5]

The Company requests confidential treatment of certain confidential information contained in the filing. Several witnesses support the Company's request for confidential treatment of that information. Each witness who supports the request explains how disclosure of the information could harm the Company or its customers.

The redacted portions of the filing contain privileged, commercially-sensitive information or trade secrets. This information derives independent economic value from not being generally known. The disclosure of this information could adversely affect Sierra's ability to obtain fuel and purchase power at competitive prices or optimize its resources for the benefit of the Company's customers.

The Company has filed one copy of the confidential information in a sealed envelope as required by the Commission's regulations. Each page has been stamped confidential and unredacted.

IX. Deviation for Regulations.

NAC § 701B.010 provides that the Commission may allow deviation from any provision of NAC Chapter 701B if:

(1) Good cause for the deviation appears;

(2) The person requesting the deviation provides a specific reference to each provision of the chapter from which the deviation is requested; and

(3) The Commission finds that the deviation is in the public interest and is not contrary to statute.

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[5] Section 703.527 to 703.5282 of the Nevada Administrative Code.

To the extent necessary, the Company requests a deviation from NAC §§ 701B.140(a), 701B.495(a) and 701B.675(a), which require the use of projected kWh for the calendar year and instead requests to use projected kWh for the program year from July 1 to June 30.

In addition, Sierra requests a deviation from the provisions of NAC §§ 701B.140(a), 701B.495(a) and 701B.675(a), which require that the calculation of the REPR includes total program costs filed with the Annual Plan. Sierra requests that the Commission allow the rate to be calculated using projected program costs as presented by Mr. Sheikh. The projected costs reflect the dollars Sierra believes will be spent in the program year based on history and estimated customer project completion rates and statutory limitations, and better reflect the ongoing costs of the programs.

X. Request to Consolidate

Sierra asks that this application be consolidated with the following filing made on March 1, 2024 for administrative efficiencies:

1. Annual Rate Adjustment Application of Nevada Power Company d/b/a NV Energy.
2. Annual Rate Adjustment Application of the Gas Division of Sierra Pacific Power Company d/b/a NV Energy.

XI. Requests for Relief

Sierra respectfully requests that the Commission issue an order granting the following relief:

1. A finding that the costs recorded in Sierra's deferred energy account were prudently incurred and are reasonable;

2. A finding that this filing fully satisfies the reporting requirements of NAC § 704.9482(6);

3. Permission to establish a new TRED rate in the amount of $0.00032/kWh;

4. Deviation from the Commission's regulations so that the Company may use its estimate of costs, rather than maximum amounts set forth in the annual plan to set the prospective component of the REPR;

5. A finding that costs recorded in the REPR regulatory asset accounts were prudently incurred and are reasonable;

6. Permission to establish a new REPR in the amount of $0.00089/kWh;

7. A finding that the costs associated with implementing energy efficiency programs recorded between January 1, 2023, and December 31, 2023, were prudently incurred and are reasonable;

8. A finding that the Amortization EEPR is just and reasonable and permission to establish the rates as proposed in the filing;

9. A finding that the Base EEPR is just and reasonable and permission to establish the rates as proposed in the filing;

10. A finding that the Amortization EEIR is just and reasonable and permission to establish the rates as proposed in the filing;

11. A finding that the Base EEIR is just and reasonable and permission to establish the rates as proposed in the filing;

12. Permission to establish a new ESPC rate in the amount of $0.00001/kWh;

13. A finding that the Commission takes administrative notice of the ESP and ESP updates filed and approved in Docket Nos. 21-06001, 22-09002, and 23-09003 and the associated orders approving each ESP and ESP update;

14. A finding that the Company satisfied compliance items as enumerated in the testimonies of Mr. Cacuci from Docket Nos. 05-08004, 06-12001, 10-07003 and 11-09003/4, Mr. Taylor from Docket Nos. 16-03004 and 17-03002, Mr. Lescenski from Docket Nos. 15-03001 and 17-03002 and Mr. Ahlstedt from Docket No. 19-03002;

15. A finding that the Company satisfied the directive to file with the Commission an earning sharing calculation as part of future annual DEAA filings as required

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

by stipulation and paragraph 194 of the Commission's modified final order in Docket No. 19-06002 issued on April 3, 2020;

16. Treatment of certain information as confidential for a period of no less than five years;

17. Consolidate the Application with the case identified in Section X above and filed on March 1, 2024.

18. All such additional relief that the Commission finds just and proper.

Respectfully submitted this 1st day of March 2024.

SIERRA PACIFIC POWER COMPANY
d/b/a NV ENERGY

<u>/s/ Michael Knox</u>

Michael Knox
Senior Attorney
6100 Neil Road
Reno, Nevada 89511
michael.knox@nvenergy.com

DRAFT NOTICE

PUBLIC UTILITIES COMMISSION OF NEVADA
DRAFT NOTICE
(Applications, Tariff Filings, Complaints, and Petitions)

Page 1 of 2

Pursuant to Nevada Administrative Code ("NAC") 703.162, the Commission requires that a draft notice be included with all applications, tariff filings, complaints and petitions. Please complete and include **ONE COPY** of this form with your filing. (Completion of this form may require the use of more than one page.)

A title that generally describes the relief requested (see NAC 703.160(5)(a)):

Annual Deferred Energy Accounting Adjustment Application of the Electric Division of Sierra Pacific Power Company d/b/a NV Energy for the 12-month period ending December 31, 2023, reset the Temporary Renewable Energy Development Charge, reset all components of the Renewable Energy Program Rate, reset the Base Energy Efficiency Program Rates, reset the Base Energy Efficiency Implementation Rates, reset the Energy Efficiency Program Amortization Rate, reset the Energy Efficiency Implementation Amortization Rate, and reset the Expanded Solar Access Program rate.

The name of the applicant, complainant, petitioner or the name of the agent for the applicant, complainant or petitioner (see NAC 703.160(5)(b)):

Sierra Pacific Power Company d/b/a NV Energy

A brief description of the purpose of the filing or proceeding, including, without limitation, a clear and concise introductory statement that summarizes the relief requested or the type of proceeding scheduled **AND** the effect of the relief or proceeding upon consumers (see NAC 703.160(5)(c)):

The filing seeks a review of fuel and purchased power expenses for the 12-month period ending December 31, 2023. The filing requests permission to reset the Temporary Renewable Energy Development Charge, and the Renewable Energy Program Rate. Finally, the filing requests permission to reset all the components of the Energy Efficiency Program Rates and Energy Efficiency Implementation Rates. The effect of granting this application will be to decrease overall revenue by approximately $5,811,987 or 0.55 percent over all rate classes.

A statement indicating whether a consumer session is required to be held pursuant to Nevada Revised Statute ("NRS") 704.069(1):[1]

Yes, a consumer session is required for this application.

If the draft notice pertains to a tariff filing, please include the tariff number **AND** the section number(s) or schedule number(s) being revised.

The tariff schedules and pages impacted by this application include Schedule EE Energy Efficiency, Sheet No. 63A; Schedule REPR Renewable Energy Program Rate, Sheet No. 63B; Statement of Rates, Sheet Nos. 63G, 63G(1), 63H, 63J, 63J(1), 63J(2), 63J(3), 63J(4), 63K, 63K(1), 63K(2), 63K(3), 63K(4), 63K(5), 63K(6), 63L, Schedule OLS Outdoor Lighting Service, Sheet No. 72; and Schedule SL Street Lighting Service (Continued), Sheet No. 75A.

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[1] NRS 704.069 states in pertinent part:

> 1. The Commission shall conduct a consumer session to solicit comments from the public in any matter pending before the Commission pursuant to NRS 704.061 to 704.110 inclusive, in which:
> (a) A public utility has filed a general rate application, an application to recover the increased cost of purchased fuel, purchased power, or natural gas purchased for resale or an application to clear its deferred accounts; and
> (b) The changes proposed in the application will result in an increase in annual gross operating revenue, as certified by the applicant, in an amount that will exceed $50,000 or 10 percent of the applicant's annual gross operating revenue, whichever is less.

EXHIBIT A

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road, Reno, Nevada **26th Revised** PUCN Sheet No. **63A**
Tariff No. **Electric No. 1** Cancelling **25th Revised** PUCN Sheet No. **63A**

SCHEDULE EE
ENERGY EFFICIENCY

APPLICABLE

The monthly energy charges for service otherwise applicable under each of the Utility's rate schedules shall be increased or decreased by the authorized Energy Efficiency Program and Implementation Rates as specified below.

TERRITORY

Entire Nevada Service Area, as specified.

RATES - Monthly billings for bundled service shall include the following:

Energy Efficiency Program and Implementation Rates, all kWh, per kWh

Rate Class	Program Rate (EEPR)	Implementation Rate (EEIR)		
All Classes	**Base**	**Base**	**Refund**	
DM-1, ODM-1, ODM-1-PDU, ODM-1-CPP	$0.00222	$0.00018	$0.00000	(I,-,-)
D-1, OD-1, OD-1-PDU, OD-1-CPP, SSR-1	$0.00231	$0.00019	$0.00000	(I,-,-)
GS-1, SSR-2, WCS	$0.00164	$0.00014	$0.00000	(I,I,-)
GS-2S, SSR-3	$0.00165	$0.00014	$0.00000	(I,I,-)
GS-2P	$0.00154	$0.00013	$0.00000	(I,I,-)
GS-2T	$0.00126	$0.00010	$0.00000	(I,-,-)
GS-2S-TOU, LSR-I	$0.00178	$0.00015	$0.00000	(I,I,-)
GS-2P-TOU	$0.00170	$0.00014	$0.00000	(I,-,-)
GS-2T-TOU	$0.00143	$0.00012	$0.00000	(I,I,-)
GS-3S, LSR-II	$0.00167	$0.00014	$0.00000	(I,I,-)
GS-3P	$0.00149	$0.00012	$0.00000	(I,I,-)
GS-3T	$0.00122	$0.00010	$0.00000	(R,R,-)
GS-4, LSR-III	$0.00155	$0.00013	$0.00000	(I,I,-)
OGS-1	$0.00160	$0.00013	$0.00000	(I,-,-)
OGS-2S	$0.00167	$0.00014	$0.00000	(I,I,-)
OGS-2P	$0.00154	$0.00013	$0.00000	(I,I,-)
OGS-2T	$0.00126	$0.00010	$0.00000	(I,-,-)
IS-1	$0.00253	$0.00021	$0.00000	(I,I,-)
WP	$0.00185	$0.00015	$0.00000	(I,-,-)
SL	$0.00131	$0.00011	$0.00000	(I,I,-)
OLS	$0.00144	$0.00012	$0.00000	(I,-,-)
All Classes	**Clearing**	**Clearing**		
	($0.00017)	$0.00000		(I,I)

Issued: **03-01-24** Effective: **10-01-24** Advice No.: **672-E**	Issued By: Janet Wells Vice President, Regulatory	

SIERRA PACIFIC POWER COMPANY dba NV ENERGY
6100 Neil Road, Reno, Nevada — **26th Revised** — PUCN Sheet No. **63B**
Tariff No. **Electric No. 1** — Cancelling **25th Revised** — PUCN Sheet No. **63B**

SCHEDULE REPR

RENEWABLE ENERGY PROGRAM RATE

APPLICABLE

The monthly energy charges for service otherwise applicable under each of the Utility's rate schedules shall be increased or decreased by the authorized Renewable Energy Program Rate specified below.

TERRITORY

Entire Nevada Service Area, as specified.

RATES - Monthly billings for bundled service shall include the following:

Renewable Energy Program Rate, all kWh, per kWh

All kWh, per kWh $0.00089 (R)

The above charge is the sum of the program rates shown below:

	Part A	Part B	
Solar Program All kWh, per kWh	$0.00000	$0.00044	(R) (R)
			(D) (D)
Small Energy Storage Program Rate All kWh, per kWh	$0.00002	($0.00008)	(R) (I)
Large Energy Storage Program Rate All kWh, per kWh	$0.00007	($0.00001)	(I) (-)
Electric Vehicle Infrastructure Demonstration Program Rate All kWh, per kWh	$0.00013	$0.00032	(R) (I)

Issued: **03-01-24**

Effective: **10-01-24**

Advice No.: **672-E**

Issued By:
Janet Wells
Vice President, Regulatory

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

97 th Revised PUCN Sheet No. 63G
Cancelling 96 th Revised PUCN Sheet No. 63G

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates

				PUBLIC POLICY RATES							
Schedule Number & Type of Charge	**BTGR**	**BTER**	**DEAA**	**TRED**	**REPR**	**UEC**	**NDPP**	**ESAP**	**EE**	**Total Rate**	
D-1 - Domestic Service											
Basic Service Charge, per month										$16.50	
Consumption Charge per kWh	$0.05745	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00233	$0.13154	(R)
Excess Energy Credit (See note 12)											
DM-1 – Domestic Multi-Family Service											
Basic Service Charge, per month										$8.00	
Consumption Charge per kWh	$0.05566	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00223	$0.12965	(R)
Excess Energy Credit (See note 12)											
GS-1 - Small General Service											
Basic Service Charge, per month										$32.30	
Consumption Charge per kWh	$0.03392	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00161	$0.10729	(R)
Additional Meter Charge per additional meter per month										$3.50	
Excess Energy Credit (See note 12)											
OD-1 TOU - Optional Domestic Service Time of Use											
Basic Service Charge, per month										$16.50	
Consumption Charge per kWh											
Summer On-Peak Period	$0.31094	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00233	$0.38503	(R)
Summer Off-Peak Period	$0.01203	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00233	$0.08612	(R)
Summer OD-REVRR (Residential Electric Vehicle Recharge Rider)	$0.00642	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00233	$0.08051	(R)
All Winter Hours	$0.01251	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00233	$0.08660	(R)
Winter OD-REVRR (Residential Electric Vehicle Recharge Rider)	$0.00642	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00233	$0.08051	(R)
Excess Energy Credit (See note 12)											
ODM-1 TOU - Optional Domestic Service Multi-Family - Time - of- Use											
Basic Service Charge, per month										$8.00	
Consumption Charge per kWh											
Summer On-Peak Period	$0.25707	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00223	$0.33106	(R)
Summer Off-Peak Period	$0.03866	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00223	$0.11265	(R)
Summer ODM-REVRR (Residential Multi-Family Electric Vehicle Recharge Rider)	$0.01039	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00223	$0.08438	(R)
All Winter Hours	$0.01692	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00223	$0.09091	(R)
Winter ODM-REVRR (Residential Multi-Family Electric Vehicle Recharge Rider)	$0.01039	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00223	$0.08438	(R)
Excess Energy Credit (See note 12)											
OGS-1-TOU – Optional General Service Time - of- Use											
Basic Service Charge, per month										$32.30	
Consumption Charge per kWh											
Summer On-Peak Period	$0.14919	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00156	$0.22251	(R)
Summer Off-Peak Period	$0.04079	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00156	$0.11411	(R)
Summer OGS-EVRR (General Service Electric Vehicle Recharge Rider)	$0.00187	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00156	$0.07519	(R)
All Winter Hours	$0.00746	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00156	$0.08078	(R)
Winter OGS-EVRR (General Service Electric Vehicle Recharge Rider)	$0.00187	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00156	$0.07519	(R)
Additional Meter Charge per additional meter per month										$3.50	
Excess Energy Credit (See note 12)											

(Continued)

Issued:	**03-01-24**	**Issued By:**	
Effective:	**10-01-24**	**Janet Wells**	
Notice No.: Advice No.:	**672-E**	**Vice President, Regulatory**	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

	35 th Revised	PUCN Sheet No. 63G(1)
Cancelling	34 th Revised	PUCN Sheet No. 63G(1)

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates
(Continued)

Schedule Number & Type of Charge	BTGR	BTER	DEAA	PUBLIC POLICY RATES: TRED	REPR	UEC	NDPP	ESAP	EE	Total Rate	
OD-1 DDP - Optional Domestic Service Daily Demand Pricing											
Basic Service Charge, per month										$9.50	
Consumption Charge per kWh	$0.02390	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00233	$0.09799	(R)
Demand Charge Per kW of Maximum Demand											
Summer On-Peak Period										$0.35	
All Winter Hours										$0.05	
Facilities Charge, Per kW of Maximum Demand										$0.21	
Excess Energy Credit (See note 12)											
ODM-1 DDP - Optional Domestic Service Multi-Family Daily Demand Pricing											
Basic Service Charge, per month										$6.25	
Consumption Charge per kWh	$0.02205	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00223	$0.09604	(R)
Demand Charge Per kW of Maximum Demand											
Summer On-Peak Period										$0.28	
All Winter Hours										$0.05	
Facilities Charge, Per kW of Maximum Demand										$0.14	
Excess Energy Credit (See note 12)											
OD-1-CPP - Optional Domestic Service Critical Peak Price											
Basic Service Charge, per month										$16.50	
Consumption Charge per kWh											
Critical Peak Period	$0.43466	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00233	$0.50875	(R)
Summer On-Peak Period	$0.29539	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00233	$0.36948	(R)
Summer Off-Peak Period	$0.01203	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00233	$0.08612	(R)
Summer OD-REVRR (Residential Electric Vehicle Recharge Rider)	$0.00642	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00233	$0.08051	(R)
All Winter Hours	$0.01251	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00233	$0.08660	(R)
Winter OD-REVRR (Residential Electric Vehicle Recharge Rider)	$0.00642	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00233	$0.08051	(R)
Excess Energy Credit (See note 12)											
ODM-1-CPP - Optional Domestic Service Multi-Family Critical Peak Price											
Basic Service Charge, per month										$8.00	
Consumption Charge per kWh											
Critical Peak Period	$0.46659	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00223	$0.54058	(R)
Summer On-Peak Period	$0.23136	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00223	$0.30535	(R)
Summer Off-Peak Period	$0.03866	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00223	$0.11265	(R)
Summer ODM-REVRR (Residential Multi-Family Electric Vehicle Recharge Rider)	$0.01039	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00223	$0.08438	(R)
All Winter Hours	$0.01692	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00223	$0.09091	(R)
Winter ODM-REVRR (Residential Multi-Family Electric Vehicle Recharge Rider)	$0.01039	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00223	$0.08438	(R)
Excess Energy Credit (See note 12)											
OD-1-CPP-DDP - Optional Domestic Service Critical Peak Price and Daily Demand Pricing											
Basic Service Charge, per month										$16.50	
Consumption Charge per kWh											
Critical Peak Period	$0.43466	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00233	$0.50875	(R)
Summer On-Peak Period	$0.20734	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00233	$0.28143	(R)
Summer Off-Peak Period	$0.01203	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00233	$0.08612	(R)

(Continued)

Issued:	**03-01-24**	**Issued By:**	
Effective:	**10-01-24**	**Janet Wells**	
Notice No.: Advice No.:	**672-E**	**Vice President, Regulatory**	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

98 th Revised PUCN Sheet No. 63H
Cancelling 97 th Revised PUCN Sheet No. 63H

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates
(Continued)

Schedule Number & Type of Charge	BTGR	BTER	DEAA	TRED (PUBLIC POLICY RATES)	REPR (PUBLIC POLICY RATES)	UEC (PUBLIC POLICY RATES)	NDPP (PUBLIC POLICY RATES)	ESAP (PUBLIC POLICY RATES)	EE (PUBLIC POLICY RATES)	Total Rate	
OD-1-CPP-DDP - Optional Domestic Service Critical Peak Price and Daily Demand Pricing (Continued)											
Summer OD-REVRR (Residential Electric Vehicle Recharge Rider)	$0.00642	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00233	$0.08051	(R)
All Winter Hours	$0.01251	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00233	$0.08660	(R)
Winter OD-REVRR (Residential Electric Vehicle Recharge Rider)	$0.00642	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00233	$0.08051	(R)
Demand Charge Per kW of Maximum Demand											
Summer On-Peak Period										$0.35	
All Winter Hours										$0.05	
Excess Energy Credit (See note 12)											
ODM-1-CPP-DDP - Optional Domestic Service - Multi Family - Critical Peak Price and Daily Demand Pricing											
Basic Service Charge, per month										$8.00	
Consumption Charge per kWh											
Critical Peak Period	$0.46659	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00223	$0.54058	(R)
Summer On-Peak Period	$0.13773	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00223	$0.21172	(R)
Summer Off-Peak Period	$0.03866	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00223	$0.11265	(R)
Summer ODM-REVRR (Residential Multi-Family Electric Vehicle Recharge Rider)	$0.01039	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00223	$0.08438	(R)
All Winter Hours	$0.01692	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00223	$0.09091	(R)
Winter ODM-REVRR (Residential Multi-Family Electric Vehicle Recharge Rider)	$0.01039	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00223	$0.08438	(R)
Demand Charge Per kW of Maximum Demand											
Summer On-Peak Period										$0.28	
All Winter Hours										$0.05	
Excess Energy Credit (See note 12)											

(Continued)

Issued: **03-01-24**	**Issued By:**	
Effective: **10-01-24**	**Janet Wells**	
Notice No.: Advice No.: **672-E**	**Vice President, Regulatory**	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

101 st Revised PUCN Sheet No. 63J
Cancelling 100 th Revised PUCN Sheet No. 63J

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates
(Continued)

				PUBLIC POLICY RATES							
Schedule Number & Type of Charge	**BTGR**	**BTER**	**DEAA**	**TRED**	**REPR**	**UEC**	**NDPP**	**ESAP**	**EE**	**Total Rate**	
GS-2 – Medium General Service											
Secondary Distribution Voltage											
Basic Service Charge, per month										$14.00	
Consumption Charge per kWh	$0.01386	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00162	$0.08724	(R)
Demand Charge, Per kW of Maximum Demand										$4.38	
Facilities Charge, Per kW of Maximum Demand										$6.75	
Additional Meter Charge per additional meter per month										$12.25	
Primary Distribution Voltage											
Basic Service Charge, per month										$19.70	
Consumption Charge per kWh	$0.01592	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00150	$0.08918	(R)
Demand Charge, Per kW of Maximum Demand										$2.70	
Facilities Charge, Per kW of Maximum Demand										$5.10	
Additional Meter Charge per additional meter per month										$103.00	
Transmission Voltage											
Basic Service Charge, per month										$73.10	
Consumption Charge per kWh	$0.01010	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00119	$0.08305	(R)
Demand Charge, Per kW of Maximum Demand										$4.11	
Facilities Charge per dollar of Utility Investment										$0.00262	
Facilities Charge per dollar of Contributed Investment										$0.00073	
Or, Facilities Charge, Per kW of Maximum Demand										$1.60	
HVD Charge, Per kW of Maximum Demand										$0.01	
Additional Meter Charge per additional meter per month										$131.00	
GS-2 TOU - Medium General Service – Time-of-Use											
Secondary Distribution Voltage											
Basic Service Charge, per month										$27.40	
Consumption Charge per kWh											
Summer On-Peak Period	$0.08234	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00176	$0.15586	(R)
Summer Off-Peak Period	$0.01396	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00176	$0.08748	(R)
All Winter Hours	$0.00367	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00176	$0.07719	(R)
Demand Charge, Per kW of Maximum Demand											
Summer On-Peak Period										$11.93	
All Winter Hours										$1.37	
Facilities Charge, Per kW of Maximum Demand										$6.85	
Additional Meter Charge per additional meter per month										$14.50	
EVCCR (Electric Vehicle Commercial Charging Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.01396	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00176	$0.08748	(R)
Winter EV Recharge Period	$0.00367	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00176	$0.07719	(R)
EVCCR BTGR Transition Rate per kWh (See Note 13)											
Summer On-Peak Period										$0.06096	
All Winter Hours										$0.00200	

Issued:	**03-01-24**	**Issued By:**	
Effective:	**10-01-24**	**Janet Wells**	
Notice No.: Advice No.:	**672-E**	**Vice President, Regulatory**	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

40 th Revised PUCN Sheet No. 63J(1)
Cancelling 39 th Revised PUCN Sheet No. 63J(1)

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates
(Continued)

				PUBLIC POLICY RATES							
Schedule Number & Type of Charge	**BTGR**	**BTER**	**DEAA**	**TRED**	**REPR**	**UEC**	**NDPP**	**ESAP**	**EE**	**Total Rate**	
GS-2 TOU - Medium General Service – Time-of-Use (Continued)											
Secondary Distribution Voltage (Continued)											
EVCCR Reduction Rate per kWh (See Note 13)											
Summer EV Recharge Period										($0.00624)	
Winter EV Recharge Period										($0.00521)	
EVCCR Demand Reduction per kW (See Note 13)											
Summer On-Peak Period										($7.16)	
All Winter Hours										($0.82)	
Primary Distribution Voltage											
Basic Service Charge, per month										$123.90	
Consumption Charge per kWh											
Summer On-Peak Period	$0.11031	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00167	$0.18374	(R)
Summer Off-Peak Period	$0.01226	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00167	$0.08569	(R)
All Winter Hours	$0.00001	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00167	$0.07344	(R)
Demand Charge Per kW of Maximum Demand											
Summer On-Peak Period										$17.09	
All Winter Hours										$1.41	
Facilities Charge, Per kW of Maximum Demand										$5.20	
Additional Meter Charge per additional meter per month										$114.25	
EVCCR (Electric Vehicle Commercial Charging Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.01226	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00167	$0.08569	(R)
Winter EV Recharge Period	$0.00001	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00167	$0.07344	(R)
EVCCR BTGR Transition Rate per kWh (See Note 13)											
Summer On-Peak Period										$0.06882	
All Winter Hours										$0.00202	
EVCCR Reduction Rate per kWh (See Note 13)											
Summer EV Recharge Period										($0.00607)	
Winter EV Recharge Period										($0.00484)	
EVCCR Demand Reduction per kW (See Note 13)											
Summer On-Peak Period										($10.25)	
All Winter Hours										($0.85)	
Transmission Voltage											
Basic Service Charge, per month										$214.30	
Consumption Charge per kWh											
Summer On-Peak Period	$0.08874	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00138	$0.16188	(R)
Summer Off-Peak Period	$0.01800	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00138	$0.09114	(R)
All Winter Hours	$0.00386	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00138	$0.07700	(R)
Demand Charge, Per kW of Maximum Demand											
Summer On-Peak Period										$12.42	
All Winter Hours										$1.04	
Facilities Charge per dollar of Utility Investment										$0.00262	
Facilities Charge per dollar of Contributed Investment										$0.00073	
Or, Facilities Charge, Per kW of Maximum Demand										$1.60	
HVD Charge, Per kW of Maxim **9/27/2023**										$0.02	
Additional Meter Charge per additional meter per month										$177.25	

(Continued)

Issued: **03-01-24**	**Issued By:**	
Effective: **10-01-24**	**Janet Wells**	
Notice No.: Advice No.: **672-E**	**Vice President, Regulatory**	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

30 th Revised PUCN Sheet No. 63J(2)
Cancelling 29 th Revised PUCN Sheet No. 63J(2)

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates
(Continued)

				PUBLIC POLICY RATES							
Schedule Number & Type of Charge	BTGR	BTER	DEAA	TRED	REPR	UEC	NDPP	ESAP	EE	Total Rate	
GS-2 TOU - Medium General Service – Time-of-Use (Continued)											
EVCCR (Electric Vehicle Commercial Charging Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.01800	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00138	$0.09114	(R)
Winter EV Recharge Period	$0.00386	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00138	$0.07700	(R)
EVCCR BTGR Transition Rate per kWh (See Note 13)											
Summer On-Peak Period										$0.06326	
All Winter Hours										$0.00180	
EVCCR Reduction Rate per kWh (See Note 13)											
Summer EV Recharge Period										($0.00664)	
Winter EV Recharge Period										($0.00523)	
EVCCR Demand Reduction per kW (See Note 13)											
Summer On-Peak Period										($7.45)	
All Winter Hours										($0.62)	
GS-3 - Large General Service											
Secondary Distribution Voltage											
Basic Service Charge, per month										$536.60	
Consumption Charge per kWh											
Summer On-Peak Period	$0.09964	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00164	$0.17304	(R)
Summer Off-Peak Period	$0.01564	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00164	$0.08904	(R)
All Winter Hours	$0.00328	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00164	$0.07668	(R)
Demand Charge, Per kW of Maximum Demand											
Summer On-Peak Period										$13.62	
All Winter Hours										$1.46	
Facilities Charge, Per kW of Maximum Demand										$6.50	
Additional Meter Charge per additional meter per month										$22.25	
EVCCR (Electric Vehicle Commercial Charging Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.01564	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00164	$0.08904	(R)
Winter EV Recharge Period	$0.00328	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00164	$0.07668	(R)
EVCCR BTGR Transition Rate per kWh (See Note 13)											
Summer On-Peak Period										$0.06012	
All Winter Hours										$0.00172	
EVCCR Reduction Rate per kWh (See Note 13)											
Summer EV Recharge Period										($0.00641)	
Winter EV Recharge Period										($0.00517)	
EVCCR Demand Reduction per kW (See Note 13)											
Summer On-Peak Period										($8.17)	
All Winter Hours										($0.88)	
Primary Distribution Voltage											
Basic Service Charge, per month										$612.10	
Consumption Charge per kWh											
Summer On-Peak Period	$0.10072	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00144	$0.17392	(R)

(Continued)

Issued: **03-01-24**	**Issued By:**	
Effective: **10-01-24**	**Janet Wells**	
Notice No.: Advice No.: **672-E**	**Vice President, Regulatory**	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

30 th Revised PUCN Sheet No. 63J(3)
Cancelling 29 th Revised PUCN Sheet No. 63J(3)

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates
(Continued)

				PUBLIC POLICY RATES							
Schedule Number & Type of Charge	**BTGR**	**BTER**	**DEAA**	**TRED**	**REPR**	**UEC**	**NDPP**	**ESAP**	**EE**	**Total Rate**	
GS-3 - Large General Service (Continued)											
Primary Distribution Voltage (Continued)											
Summer Off-Peak Period	$0.01654	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00144	$0.08974	(R)
All Winter Hours	$0.00160	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00144	$0.07480	(R)
Demand Charge Per kW of Maximum Demand											
Summer On-Peak Period										$14.55	
All Winter Hours										$1.64	
Facilities Charge, Per kW of Maximum Demand										$7.65	
Additional Meter Charge per additional meter per month										$127.00	
EVCCR (Electric Vehicle Commercial Charging Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.01654	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00144	$0.08974	(R)
Winter EV Recharge Period	$0.00160	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00144	$0.07480	(R)
EVCCR BTGR Transition Rate per kWh (See Note 13)											
Summer On-Peak Period										$0.05855	
All Winter Hours										$0.00180	
EVCCR Reduction Rate per kWh (See Note 13)											
Summer EV Recharge Period										($0.00650)	
Winter EV Recharge Period										($0.00500)	
EVCCR Demand Reduction per kW (See Note 13)											
Summer On-Peak Period										($8.73)	
All Winter Hours										($0.98)	
Transmission Voltage											
Basic Service Charge, per month										$653.70	
Consumption Charge per kWh											
Summer On-Peak Period	$0.10910	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00115	$0.18201	(R)
Summer Off-Peak Period	$0.01991	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00115	$0.09282	(R)
All Winter Hours	$0.00554	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00115	$0.07845	(R)
Demand Charge Per kW of Maximum Demand											
Summer On-Peak Period										$9.22	
All Winter Hours										$0.91	
Facilities Charge per dollar of Utility Investment										$0.00262	
Facilities Charge per dollar of Contributed Investment										$0.00073	
Or, Facilities Charge, Per kW of Maximum Demand										$1.60	
HVD Charge, Per kW of Maximum Demand										$0.01	
Additional Meter Charge per additional meter per month										$175.25	
EVCCR (Electric Vehicle Commercial Charging Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.01991	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00115	$0.09282	(R)
Winter EV Recharge Period	$0.00554	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00115	$0.07845	(R)
EVCCR BTGR Transition Rate per kWh (See Note 13)											
Summer On-Peak Period										$0.03006	
All Winter Hours										$0.00100	

(Continued)

Issued: **03-01-24**	**Issued By:**	
Effective: **10-01-24**	**Janet Wells**	
Notice No.: Advice No.: **672-E**	**Vice President, Regulatory**	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

	90 th Revised	PUCN Sheet No. 63K
Cancelling	89 th Revised	PUCN Sheet No. 63K

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates
(Continued)

				PUBLIC POLICY RATES							
Schedule Number & Type of Charge	BTGR	BTER	DEAA	TRED	REPR	UEC	NDPP	ESAP	EE	Total Rate	
GS-3 - Large General Service (Continued)											
Transmission Voltage (Continued)											
EVCCR Reduction Rate per kWh (See Note 13)											
Summer EV Recharge Period										($0.00683)	
Winter EV Recharge Period										($0.00540)	
EVCCR Demand Reduction per kW (See Note 13)											
Summer On-Peak Period										($5.53)	
All Winter Hours										($0.55)	
WP - City of Elko Water Pumping											
Basic Service Charge, per month										$3,728.90	
Consumption Charge per kWh	$0.04701	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00183	$0.12060	(R)
IS-1 - Irrigation Service											
Basic Service Charge, per month										$31.50	
Consumption Charge per kWh	$0.06936	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00257	$0.14369	(R)
Additional Meter Charge per additional meter per month										$5.00	
IS-1 TOU - Irrigation Service											
Basic Service Charge, per month										$31.50	
Consumption Charge per kWh											
Summer On-Peak Period	$0.13869	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00257	$0.21302	(R)
Summer Off-Peak Period	$0.07511	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00257	$0.14944	(R)
All Winter Hours	$0.02406	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00257	$0.09839	(R)
Additional Meter Charge per additional meter per month										$5.00	
IS-2 - Interruptible Irrigation Service (See Note 15)											
Consumption Charge per kWh	$0.00000	$0.06751	$0.00000	$0.00000	$0.00000	$0.00039	$0.00074	$0.00002	$0.00000	$0.06866	
OGS-2-TOU - Optional Medium General Service Time-of-Use											
Secondary Distribution Voltage											
Basic Service Charge, per month										$27.60	
Consumption Charge per kWh											
Summer On-Peak Period	$0.08460	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00164	$0.15800	(R)
Summer Off-Peak Period	$0.01618	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00164	$0.08958	(R)
All Winter Hours	$0.00581	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00164	$0.07921	(R)
Demand Charge, Per kW of Maximum Demand											
Summer On-Peak Period										$9.15	
All Winter Hours										$0.81	
Facilities Charge, Per kW of Maximum Demand										$6.40	
Additional Meter Charge per additional meter per month										$12.25	
OGS-EVRR (General Service Electric Vehicle Recharge Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.00972	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00164	$0.08312	(R)
Winter EV Recharge Period	$0.00039	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00164	$0.07379	(R)
EVCCR (Electric Vehicle Commercial Charging Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.01618	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00164	$0.08958	(R)
Winter EV Recharge Period	$0.00581	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00164	$0.07921	(R)

(Continued)

Issued:	**03-01-24**	**Issued By:**	
Effective:	**10-01-24**	**Janet Wells**	
Notice No.: Advice No.:	**672-E**	**Vice President, Regulatory**	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

70 th Revised PUCN Sheet No. 63K(1)
Cancelling 69 th Revised PUCN Sheet No. 63K(1)

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates
(Continued)

				PUBLIC POLICY RATES							
Schedule Number & Type of Charge	**BTGR**	**BTER**	**DEAA**	**TRED**	**REPR**	**UEC**	**NDPP**	**ESAP**	**EE**	**Total Rate**	
OGS-2-TOU - Optional Medium General Service Time-of-Use (Continued)											
Secondary Distribution Voltage (Continued)											
EVCCR BTGR Transition Rate per kWh (See Note 13)											
Summer On-Peak Period										$0.05560	
All Winter Hours										$0.00164	
EVCCR Reduction Rate per kWh (See Note 13)											
Summer EV Recharge Period										($0.00646)	
Winter EV Recharge Period										($0.00542)	
EVCCR Demand Reduction per kW (See Note 13)											
Summer On-Peak Period										($5.49)	
All Winter Hours										($0.49)	
Primary Distribution Voltage											
Basic Service Charge, per month										$74.40	
Consumption Charge per kWh											
Summer On-Peak Period	$0.08460	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00150	$0.15786	(R)
Summer Off-Peak Period	$0.01618	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00150	$0.08944	(R)
All Winter Hours	$0.00581	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00150	$0.07907	(R)
Demand Charge, Per kW of Maximum Demand											
Summer On-Peak Period										$9.68	
All Winter Hours										$0.87	
Facilities Charge, Per kW of Maximum Demand										$5.10	
Additional Meter Charge per additional meter per month										$103.00	
OGS-EVRR (General Service Electric Vehicle Recharge Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.00972	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00150	$0.08298	(R)
Winter EV Recharge Period	$0.00039	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00150	$0.07365	(R)
EVCCR (Electric Vehicle Commercial Charging Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.01618	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00150	$0.08944	(R)
Winter EV Recharge Period	$0.00581	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00150	$0.07907	(R)
EVCCR BTGR Transition Rate per kWh (See Note 13)											
Summer On-Peak Period										$0.05076	
All Winter Hours										$0.00349	
EVCCR Reduction Rate per kWh (See Note 13)											
Summer EV Recharge Period										($0.00646)	
Winter EV Recharge Period										($0.00542)	
EVCCR Demand Reduction per kW (See Note 13)											
Summer On-Peak Period										($5.81)	
All Winter Hours										($0.52)	
Transmission Voltage											
Basic Service Charge, per month										$82.50	
Consumption Charge per kWh											
Summer On-Peak Period	$0.08460	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00119	$0.15755	(R)
Summer Off-Peak Period	$0.01618	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00119	$0.08913	(R)
All Winter Hours	$0.00581	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00119	$0.07876	(R)

(Continued)

Issued:	**03-01-24**	**Issued By:**	
Effective:	**10-01-24**	**Janet Wells**	
Notice No.: Advice No.:	**672-E**	**Vice President, Regulatory**	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

	68 th Revised	PUCN Sheet No. 63K(2)
Cancelling	67 th Revised	PUCN Sheet No. 63K(2)

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates
(Continued)

				PUBLIC POLICY RATES							
Schedule Number & Type of Charge	**BTGR**	**BTER**	**DEAA**	**TRED**	**REPR**	**UEC**	**NDPP**	**ESAP**	**EE**	**Total Rate**	
OGS-2-TOU - Optional Medium General Service Time-of-Use (Continued)											
Transmission Voltage (Continued)											
Demand Charge Per kW of Maximum Demand											
Summer On-Peak Period										$11.87	
All Winter Hours										$0.86	
Facilities Charge per dollar of Utility Investment										$0.00262	
Facilities Charge per dollar of Contributed Investment										$0.00073	
Or, Facilities Charge, Per kW of Maximum Demand										$1.60	
HVD Charge, Per kW of Maximum Demand										$0.01	
Additional Meter Charge per additional meter per month										$131.00	
OGS-EVRR (General Service Electric Vehicle Recharge Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.00972	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00119	$0.08267	(R)
Winter EV Recharge Period	$0.00039	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00119	$0.07334	(R)
EVCCR (Electric Vehicle Commercial Charging Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.01618	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00119	$0.08913	(R)
Winter EV Recharge Period	$0.00581	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00119	$0.07876	(R)
EVCCR BTGR Transition Rate per kWh (See Note 13)											
Summer On-Peak Period										$0.05076	
All Winter Hours										$0.00349	
EVCCR Reduction Rate per kWh (See Note 13)											
Summer EV Recharge Period										($0.00646)	
Winter EV Recharge Period										($0.00542)	
EVCCR Demand Reduction per kW (See Note 13)											
Summer On-Peak Period										($7.12)	
All Winter Hours										($0.52)	
GS-4 – Large Transmission Service											
Basic Service Charge, per month										$1,522.40	
Facilities Charge, (See Schedule GS-4), per dollar of Investment										$0.00311	
Tier 1 Rates (See Note 16)											
Demand Charge, for each kW of maximum billing demand											
Summer On-Peak Period										$17.99	
All Winter Hours										$1.91	
Consumption Charge per kWh											
Summer On-Peak Period	$0.09374	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00151	$0.16701	(R)
Summer Off-Peak Period	$0.01550	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00151	$0.08877	(R)
All Winter Hours	$0.00258	$0.06440	$0.00500	$0.00032	$0.00089	$0.00039	$0.00074	$0.00002	$0.00151	$0.07585	(R)
Additional Meter Charge per additional meter per month										$214.50	
Tier 2 Rates (reserved for future use)											

(Continued)

Issued:	**03-01-24**	**Issued By:**	
Effective:	**10-01-24**	**Janet Wells**	
Notice No.: Advice No.:	**672-E**	**Vice President, Regulatory**	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

70 th Revised PUCN Sheet No. 63L
Cancelling 69 th Revised PUCN Sheet No. 63L

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates
(Continued)

Schedule Number & Type of Charge	BTGR	BTER	DEAA	TRED	REPR	UEC	NDPP	ESAP	EE	Total Rate	
				PUBLIC POLICY RATES							
WCS - Wireless Communication Service											
Basic Service Charge, per month										$6.70	
Consumption Charge per month, per installed device											
(rate includes UEC):											
Level 1										$5.89	(R)
Level 2										$11.75	(R)
Level 3										$17.61	(R)
NGR – Optional NV GreenEnergy Rider											
(in addition to other rates and assessments paid by the Customer)											
Consumption Charge per kWh											
Existing Renewable Resource Rate										$0.00103	
ESER - Expanded Solar Energy Rate											
(in addition to other rates and assessments paid by the Customer)											
Consumption Charge per kWh											
ESER (see note 10)										$0.05645	
ESER LID (see note 11)										$0.05645	

Notes

1. The charges shown above are subject to adjustments for taxes and assessments as specified in the Tax Adjustment Rider (PUCN Sheet No. 63E) and Schedule MC (PUCN Sheet Nos. 63C-63D.)
2. BTGR = Base Tariff General Rate
3. BTER = Base Tariff Energy Rate
4. TRED = Temporary Renewable Energy Development Charge.
5. REPR = Renewable Energy Program Rate (see Schedule REPR, PUCN Sheet No. 63B).
6. UEC = Universal Energy Charge (see Special Condition 1 of the applicable rate schedule).
7. DEAA = Deferred Energy Accounting Adjustment (see Schedule DEAA, PUCN Sheet No. 63).
8. NDPP = Natural Disaster Protection Plan Rate (see Schedule NDPP, PUCN Sheet No. 80S).
9. ESAP = Expanded Solar Access Program Rate (see Schedule ESAP, PUCN Sheet No. 81AZ(2)).
10. ESER = Expanded Solar Energy Rate (see Schedule ESER, PUCN Sheet Nos. 81AZ-81AZ(1)).
11. ESER LID = Expanded Solar Energy Rate Low Income Discount Rate (see Schedule ESER, PUCN Sheet Nos. 81AZ-81AZ(1)).
12. The Excess Energy Credit is determined by the appropriate NMR Rider - NMR-G and NMR-405. See pages 63H(1) and 63I for the appropriate credit by Rate Class Rider.
13. Customers on EVCCR-TOU rider are subject to EVCCR BTGR Transition Rate and shall be credited with EVCCR Reduction Rate and EVCCR Demand Rate Reduction.
14. Time-of-Use and Season periods are defined in the Special Conditions of the applicable rate schedule.
15. All rate schedules that contain a demand billing component are also subject to the Power Factor Adjustment charge (see the Special Conditions of the applicable rate schedule.)
16. For the billing periods November 1 through the end of February, the billing provisions of Schedule No. IS-1 are applicable.
17. Tier 1 rates for demand and consumption are applicable to that portion of Customer's load identified in the service agreement as tied to Tier 1 rates, subject to the Special Conditions of the GS-4 rate schedule.
18. HVD Charge not applicable to Customers that directly connect to FERC Transmission.
19. Other charges may apply, please see the applicable rate schedule.

(Continued)

Issued:	**03-01-24**	**Issued By:**	
Effective:	**10-01-24**	**Janet Wells**	
Notice No.:			
Advice No.:	**672-E**	**Vice President, Regulatory**	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road, Reno, Nevada — **161st Revised** — PUCN Sheet No. **72**
Tariff No. **Electric No. 1** — Cancelling **160th Revised** — PUCN Sheet No. **72**

Schedule No. OLS
OUTDOOR LIGHTING SERVICE

APPLICABLE

To all classes of Customers for lighting outdoor areas other than public streets, alleys, roads and highways. Lighting service will be furnished from dusk-to-dawn by Utility-owned vertically mounted lamps supplied from Utility's 120/240 volt overhead and underground circuits and mounted on Utility-owned poles. This schedule is closed to new installations.

TERRITORY

Entire Nevada Service Area

RATES

The following rates will be charged per lamp, per month for energy, maintenance and facilities as listed below:

Bundled Service

Class Codes	Lamp Type	Watts	kWh/Mo	Overhead/ Multi-Use Pole	Overhead/ Light Only/ Wood Pole	Overhead/ Light Only/ Other Pole	Underground/ Light Only/ Wood Pole	Underground/ Light Only/ Other Pole	
	Mercury Vapor: (Rate Codes)			(007)	(009)	(011)	(013)	(015)	
(17)	175 W	206	71	$17.12	$26.07	$40.89	$34.23	$38.94	(R)
(21)	400 W	455	157	29.87	40.51	49.76	48.67	46.20	(R)
	High Pressure Sodium: (Rate Codes)			(001)	(003)	(005)	(033)	(035)	
(31)	70 W	84	29	12.61	21.56	32.33	33.42	34.42	(R)
(32)	100 W	118	41	13.95	22.90	33.67	34.76	35.76	(R)
(33)	150 W	194	67	16.69	25.64	36.41	33.80	38.52	(R)
	200 W	229	79	N/A	32.88	N/A	N/A	N/A	(R)
	Light Emitting Diode (LED): (Rate Codes)			(001)	(003)	(005)	(033)	(035)	
		51	18	14.79	25.80	32.08	34.53	34.73	(I)

Additional Services:

(37)	Additional Wood Pole	$20.43
(38)	Additional Other Pole	$13.36
(39)	Additional 130 Ft. Underground	$6.37

The above rates include a Base Tariff Energy Rate (BTER) of $0.06440 per kWh, a Temporary Renewable Energy Development Charge (TRED) of $0.00032 per kWh, an Energy Efficiency Charge (EE) of $0.00139 per kWh, a Renewable Energy Program Rate (REPR) of $0.00089 per kWh, a Deferred Energy Accounting Adjustment (see Schedule DEAA) and a Natural Disaster Protection Plan Rate (NDPP) of $0.00074 per kWh, and the Expanded Solar Access Program Rate (ESAP) of $0.00002 per kWh, multiplied by the monthly kWh shown, for each lamp. (R) (I) (R)

(Continued)

Issued: **03-01-24**
Effective: **10-01-24**
Notice No:
Advice No.: **672-E**

Issued By:
Janet Wells
Vice President, Regulatory

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road, Reno, Nevada — **126th Revised** PUCN Sheet No. **75A**
Tariff No. **Electric No. 1** Cancelling **125th Revised** PUCN Sheet No. **75A**

Schedule No. SL
STREET LIGHTING SERVICE
(Continued)

RATES (Continued)

Bundled Service

Lamp Type	kWh/ Mo.	Multi-use Pole	Light Only/ Wood Pole	Light Only/ Other Pole	Service to Customer-Owned Lamps Non-metered	
Mercury Vapor:						
175W	67	$12.63	$16.15	$19.63	N/A	(R)
High Pressure Sodium:						
70W	29	$8.60	$12.13	$15.61	N/A	(R)
100W	41	9.87	13.39	16.87	$4.37	(R)
150W	59	11.98	17.00	18.97	6.27	(R)
200W	79	14.13	19.15	21.12	8.42	(R)
Light Emitting Diode (LED):						
Small	12	$8.08	$12.32	$12.93	$1.28	(R)
Decorative	24	2.56	N/A	24.72	2.56	(R)
Medium	26	11.59	17.35	14.97	2.76	(R)
Large	40	13.59	19.89	20.42	4.26	(R)

The above rates include a Base Tariff Energy Rate (BTER) of $0.06440 per kWh, a Temporary Renewable Energy Development Charge (TRED) of $0.00032 per kWh, an (R) Energy Efficiency Charge (EE) of $0.00125 per kWh, a Renewable Energy Program (I) Rate (REPR) of $0.00089 per kWh, a Deferred Energy Accounting Adjustment Rate (see (R) Schedule DEAA), a Natural Disaster Protection Plan Rate (NDPP) of $0.00074 per kWh, and the Expanded Solar Access Program Rate (ESAP) of $0.00002 per kWh multiplied by the monthly kWh shown, for each lamp.

Late Charge

The Utility may charge a fee as set forth in Schedule MC for the late payment of a bill.

Tax Adjustment Charge:

The charges shown above are subject to adjustments for taxes and assessments as specified in the Tax Adjustment Rider (PUCN Sheet No. 63E).

Universal Energy Charge (UEC)

All kWh Per kWh $0.00039

(Continued)

Issued: **03-01-24** Effective: **10-01-24** Notice No.: Advice No.: **672-E**	Issued By: Janet Wells Vice President, Regulatory	

EXHIBIT B

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road, Reno, Nevada — **25th Revised** — PUCN Sheet No. **63A**
Tariff No. **Electric No. 1** — Cancelling **24th Revised** — PUCN Sheet No. **63A**

SCHEDULE EE
ENERGY EFFICIENCY

APPLICABLE

The monthly energy charges for service otherwise applicable under each of the Utility's rate schedules shall be increased or decreased by the authorized Energy Efficiency Program and Implementation Rates as specified below.

TERRITORY

Entire Nevada Service Area, as specified.

RATES - Monthly billings for bundled service shall include the following:

Energy Efficiency Program and Implementation Rates, all kWh, per kWh

Rate Class	Program Rate (EEPR)	Implementation Rate (EEIR)		
All Classes	**Base**	**Base**	**Refund**	
DM-1, ODM-1, ODM-1-PDU, ODM-1-CPP	$0.00217	$0.00018	$0.00000	(I)(I)(-)
D-1, OD-1, OD-1-PDU, OD-1-CPP, SSR-1	$0.00226	$0.00019	$0.00000	(I)(I)(-)
GS-1, SSR-2, WCS	$0.00160	$0.00013	$0.00000	(R)(-)(-)
GS-2S, SSR-3	$0.00161	$0.00013	$0.00000	(R)(-)(-)
GS-2P	$0.00149	$0.00012	$0.00000	(I)I)(-)
GS-2T	$0.00123	$0.00010	$0.00000	(R)(R)(-)
GS-2S-TOU, LSR-I	$0.00173	$0.00014	$0.00000	(I)(I)(-)
GS-2P-TOU	$0.00165	$0.00014	$0.00000	(I)(I)(-)
GS-2T-TOU	$0.00139	$0.00011	$0.00000	(I)(I)(-)
GS-3S, LSR-II	$0.00145	$0.00012	$0.00000	(R)(R)(-)
GS-3P	$0.00130	$0.00011	$0.00000	(R)(R)(-)
GS-3T	$0.00139	$0.00011	$0.00000	(I)(I)(-)
GS-4, LSR-III	$0.00149	$0.00012	$0.00000	(I)(I)(-)
OGS-1	$0.00156	$0.00013	$0.00000	(I)(I)(-)
OGS-2S	$0.00163	$0.00013	$0.00000	(I)(-)(-)
OGS-2P	$0.00149	$0.00012	$0.00000	(I)(I)(-)
OGS-2T	$0.00123	$0.00010	$0.00000	(R)(R)(-)
IS-1	$0.00244	$0.00020	$0.00000	(I)(I)(-)
WP	$0.00180	$0.00015	$0.00000	(I)(I)(-)
SL	$0.00126	$0.00010	$0.00000	(I)(I)(-)
OLS	$0.00140	$0.00012	$0.00000	(I)(I)(-)
All Classes	**Clearing**	**Clearing**		
	($0.00067)	($0.00006)		(R)(R)

Issued: **09-27-23**

Effective: **10-01-23**

Advice No.: **663-E-R**

Issued By:
Janet Wells
Vice President, Regulatory

SIERRA PACIFIC POWER COMPANY dba NV ENERGY
6100 Neil Road, Reno, Nevada — **25th Revised** — PUCN Sheet No. **63B**
Tariff No. **Electric No. 1** — Cancelling **24th Revised** — PUCN Sheet No. **63B**

SCHEDULE REPR

RENEWABLE ENERGY PROGRAM RATE

APPLICABLE

The monthly energy charges for service otherwise applicable under each of the Utility's rate schedules shall be increased or decreased by the authorized Renewable Energy Program Rate specified below.

TERRITORY

Entire Nevada Service Area, as specified.

RATES - Monthly billings for bundled service shall include the following:

Renewable Energy Program Rate, all kWh, per kWh

All kWh, per kWh $0.00177 (I)

The above charge is the sum of the program rates shown below:

	Part A	Part B	
Solar Program All kWh, per kWh	$0.00003	$0.00133	(-) (I)
Wind Demonstration Program All kWh, per kWh	$0.00000	$0.00000	
Waterpower Demonstration Program All kWh, per kWh	$0.00000	$0.00000	
Small Energy Storage Program Rate All kWh, per kWh	$0.00006	($0.00009)	(R) (R)
Large Energy Storage Program Rate All kWh, per kWh	$0.00004	($0.00001)	(I) (-)
Electric Vehicle Infrastructure Demonstration Program Rate All kWh, per kWh	$0.00040	$0.00001	(I) (I)

Issued: **03-01-23**
Effective: **10-01-23**
Advice No.: **663-E**

Issued By:
Janet Wells
Vice President, Regulatory

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

96 th Revised PUCN Sheet No. 63G
Cancelling 95 th Revised PUCN Sheet No. 63G

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates

Schedule Number & Type of Charge	BTGR	BTER	DEAA	TRED (PUBLIC POLICY RATES)	REPR (PUBLIC POLICY RATES)	UEC (PUBLIC POLICY RATES)	NDPP (PUBLIC POLICY RATES)	ESAP (PUBLIC POLICY RATES)	EE (PUBLIC POLICY RATES)	Total Rate	
D-1 - Domestic Service											
Basic Service Charge, per month										$16.50	
Consumption Charge per kWh	$0.05745	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00172	$0.13221	(R)
Excess Energy Credit (See note 12)											
DM-1 – Domestic Multi-Family Service											
Basic Service Charge, per month										$8.00	
Consumption Charge per kWh	$0.05566	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00162	$0.13032	(R)
Excess Energy Credit (See note 12)											
GS-1 - Small General Service											
Basic Service Charge, per month										$32.30	
Consumption Charge per kWh	$0.03392	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00100	$0.10796	(R)
Additional Meter Charge per additional meter per month										$3.50	
Excess Energy Credit (See note 12)											
OD-1 TOU - Optional Domestic Service Time of Use											
Basic Service Charge, per month										$16.50	
Consumption Charge per kWh											
Summer On-Peak Period	$0.31094	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00172	$0.38570	(R)
Summer Off-Peak Period	$0.01203	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00172	$0.08679	(R)
Summer OD-REVRR (Residential Electric Vehicle Recharge Rider)	$0.00642	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00172	$0.08118	(R)
All Winter Hours	$0.01251	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00172	$0.08727	(R)
Winter OD-REVRR (Residential Electric Vehicle Recharge Rider)	$0.00642	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00172	$0.08118	(R)
Excess Energy Credit (See note 12)											
ODM-1 TOU - Optional Domestic Service Multi-Family - Time - of- Use											
Basic Service Charge, per month										$8.00	
Consumption Charge per kWh											
Summer On-Peak Period	$0.25707	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00162	$0.33173	(R)
Summer Off-Peak Period	$0.03866	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00162	$0.11332	(R)
Summer ODM-REVRR (Residential Multi-Family Electric Vehicle Recharge Rider)	$0.01039	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00162	$0.08505	(R)
All Winter Hours	$0.01692	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00162	$0.09158	(R)
Winter ODM-REVRR (Residential Multi-Family Electric Vehicle Recharge Rider)	$0.01039	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00162	$0.08505	(R)
Excess Energy Credit (See note 12)											
OGS-1-TOU – Optional General Service Time - of- Use											
Basic Service Charge, per month										$32.30	
Consumption Charge per kWh											
Summer On-Peak Period	$0.14919	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00096	$0.22319	(R)
Summer Off-Peak Period	$0.04079	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00096	$0.11479	(R)
Summer OGS-EVRR (General Service Electric Vehicle Recharge Rider)	$0.00187	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00096	$0.07587	(R)
All Winter Hours	$0.00746	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00096	$0.08146	(R)
Winter OGS-EVRR (General Service Electric Vehicle Recharge Rider)	$0.00187	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00096	$0.07587	(R)
Additional Meter Charge per additional meter per month										$3.50	
Excess Energy Credit (See note 12)											

(Continued)

Issued: **11-15-23**	**Issued By:**	
Effective: **01-01-24**	**Janet Wells**	
Notice No.: Advice No.: **23-04(E)**	**Vice President, Regulatory**	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

	34 th Revised	PUCN Sheet No.	63G(1)
Cancelling	33 rd Revised	PUCN Sheet No.	63G(1)

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates
(Continued)

Schedule Number & Type of Charge	BTGR	BTER	DEAA	TRED (PUBLIC POLICY RATES)	REPR (PUBLIC POLICY RATES)	UEC (PUBLIC POLICY RATES)	NDPP (PUBLIC POLICY RATES)	ESAP (PUBLIC POLICY RATES)	EE (PUBLIC POLICY RATES)	Total Rate	
OD-1 DDP - Optional Domestic Service Daily Demand Pricing											
Basic Service Charge, per month										$9.50	
Consumption Charge per kWh	$0.02390	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00172	$0.09866	(R)
Demand Charge Per kW of Maximum Demand											
Summer On-Peak Period										$0.35	
All Winter Hours										$0.05	
Facilities Charge, Per kW of Maximum Demand										$0.21	
Excess Energy Credit (See note 12)											
ODM-1 DDP - Optional Domestic Service Multi-Family Daily Demand Pricing											
Basic Service Charge, per month										$6.25	
Consumption Charge per kWh	$0.02205	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00162	$0.09671	(R)
Demand Charge Per kW of Maximum Demand											
Summer On-Peak Period										$0.28	
All Winter Hours										$0.05	
Facilities Charge, Per kW of Maximum Demand										$0.14	
Excess Energy Credit (See note 12)											
OD-1-CPP - Optional Domestic Service Critical Peak Price											
Basic Service Charge, per month										$16.50	
Consumption Charge per kWh											
Critical Peak Period	$0.43466	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00172	$0.50942	(R)
Summer On-Peak Period	$0.29539	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00172	$0.37015	(R)
Summer Off-Peak Period	$0.01203	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00172	$0.08679	(R)
Summer OD-REVRR (Residential Electric Vehicle Recharge Rider)	$0.00642	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00172	$0.08118	(R)
All Winter Hours	$0.01251	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00172	$0.08727	(R)
Winter OD-REVRR (Residential Electric Vehicle Recharge Rider)	$0.00642	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00172	$0.08118	(R)
Excess Energy Credit (See note 12)											
ODM-1-CPP - Optional Domestic Service Multi-Family Critical Peak Price											
Basic Service Charge, per month										$8.00	
Consumption Charge per kWh											
Critical Peak Period	$0.46659	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00162	$0.54125	(R)
Summer On-Peak Period	$0.23136	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00162	$0.30602	(R)
Summer Off-Peak Period	$0.03866	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00162	$0.11332	(R)
Summer ODM-REVRR (Residential Multi-Family Electric Vehicle Recharge Rider)	$0.01039	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00162	$0.08505	(R)
All Winter Hours	$0.01692	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00162	$0.09158	(R)
Winter ODM-REVRR (Residential Multi-Family Electric Vehicle Recharge Rider)	$0.01039	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00162	$0.08505	(R)
Excess Energy Credit (See note 12)											
OD-1-CPP-DDP - Optional Domestic Service Critical Peak Price and Daily Demand Pricing											
Basic Service Charge, per month										$16.50	
Consumption Charge per kWh											
Critical Peak Period	$0.43466	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00172	$0.50942	(R)
Summer On-Peak Period	$0.20734	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00172	$0.28210	(R)
Summer Off-Peak Period	$0.01203	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00172	$0.08679	(R)

(Continued)

Issued:	**11-15-23**	**Issued By:**	
Effective:	**01-01-24**	**Janet Wells**	
Notice No.: Advice No.:	**23-04(E)**	**Vice President, Regulatory**	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

97 th Revised PUCN Sheet No. 63H
Cancelling 96 th Revised PUCN Sheet No. 63H

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates
(Continued)

				PUBLIC POLICY RATES							
Schedule Number & Type of Charge	**BTGR**	**BTER**	**DEAA**	**TRED**	**REPR**	**UEC**	**NDPP**	**ESAP**	**EE**	**Total Rate**	
OD-1-CPP-DDP - Optional Domestic Service Critical Peak Price and Daily Demand Pricing (Continued)											
Summer OD-REVRR (Residential Electric Vehicle Recharge Rider)	$0.00642	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00172	$0.08118	(R)
All Winter Hours	$0.01251	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00172	$0.08727	(R)
Winter OD-REVRR (Residential Electric Vehicle Recharge Rider)	$0.00642	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00172	$0.08118	(R)
Demand Charge Per kW of Maximum Demand											
Summer On-Peak Period										$0.35	
All Winter Hours										$0.05	
Excess Energy Credit (See note 12)											
ODM-1-CPP-DDP - Optional Domestic Service - Multi Family - Critical Peak Price and Daily Demand Pricing											
Basic Service Charge, per month										$8.00	
Consumption Charge per kWh											
Critical Peak Period	$0.46659	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00162	$0.54125	(R)
Summer On-Peak Period	$0.13773	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00162	$0.21239	(R)
Summer Off-Peak Period	$0.03866	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00162	$0.11332	(R)
Summer ODM-REVRR (Residential Multi-Family Electric Vehicle Recharge Rider)	$0.01039	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00162	$0.08505	(R)
All Winter Hours	$0.01692	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00162	$0.09158	(R)
Winter ODM-REVRR (Residential Multi-Family Electric Vehicle Recharge Rider)	$0.01039	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00162	$0.08505	(R)
Demand Charge Per kW of Maximum Demand											
Summer On-Peak Period										$0.28	
All Winter Hours										$0.05	
Excess Energy Credit (See note 12)											

(Continued)

Issued: **11-15-23**	**Issued By:**	
Effective: **01-01-24**	**Janet Wells**	
Notice No.: Advice No.: **23-04(E)**	**Vice President, Regulatory**	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

	100 th Revised	PUCN Sheet No. 63J
Cancelling	99 th Revised	PUCN Sheet No. 63J

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates
(Continued)

Schedule Number & Type of Charge	BTGR	BTER	DEAA	TRED (PUBLIC POLICY RATES)	REPR	UEC	NDPP	ESAP	EE	Total Rate	
GS-2 – Medium General Service											
Secondary Distribution Voltage											
Basic Service Charge, per month										$14.00	
Consumption Charge per kWh	$0.01386	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00101	$0.08791	(R)
Demand Charge, Per kW of Maximum Demand										$4.38	
Facilities Charge, Per kW of Maximum Demand										$6.75	
Additional Meter Charge per additional meter per month										$12.25	
Primary Distribution Voltage											
Basic Service Charge, per month										$19.70	
Consumption Charge per kWh	$0.01592	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00088	$0.08984	(R)
Demand Charge, Per kW of Maximum Demand										$2.70	
Facilities Charge, Per kW of Maximum Demand										$5.10	
Additional Meter Charge per additional meter per month										$103.00	
Transmission Voltage											
Basic Service Charge, per month										$73.10	
Consumption Charge per kWh	$0.01010	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00060	$0.08374	(R)
Demand Charge, Per kW of Maximum Demand										$4.11	
Facilities Charge per dollar of Utility Investment										$0.00262	
Facilities Charge per dollar of Contributed Investment										$0.00073	
Or, Facilities Charge, Per kW of Maximum Demand										$1.60	
HVD Charge, Per kW of Maximum Demand										$0.01	
Additional Meter Charge per additional meter per month										$131.00	
GS-2 TOU - Medium General Service – Time-of-Use											
Secondary Distribution Voltage											
Basic Service Charge, per month										$27.40	
Consumption Charge per kWh											
Summer On-Peak Period	$0.08234	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00114	$0.15652	(R)
Summer Off-Peak Period	$0.01396	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00114	$0.08814	(R)
All Winter Hours	$0.00367	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00114	$0.07785	(R)
Demand Charge, Per kW of Maximum Demand											
Summer On-Peak Period										$11.93	
All Winter Hours										$1.37	
Facilities Charge, Per kW of Maximum Demand										$6.85	
Additional Meter Charge per additional meter per month										$14.50	
EVCCR (Electric Vehicle Commercial Charging Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.01396	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00114	$0.08814	(R)
Winter EV Recharge Period	$0.00367	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00114	$0.07785	(R)
EVCCR BTGR Transition Rate per kWh (See Note 13)											
Summer On-Peak Period										$0.06096	
All Winter Hours										$0.00200	

Issued:	**11-15-23**	**Issued By:**	
Effective:	**01-01-24**	**Janet Wells**	
Notice No.: Advice No.:	**23-04(E)**	**Vice President, Regulatory**	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

39 th Revised PUCN Sheet No. 63J(1)
Cancelling 38 th Revised PUCN Sheet No. 63J(1)

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates
(Continued)

Schedule Number & Type of Charge	BTGR	BTER	DEAA	TRED	REPR	UEC	NDPP	ESAP	EE	Total Rate	
				PUBLIC POLICY RATES							
GS-2 TOU - Medium General Service – Time-of-Use (Continued)											
Secondary Distribution Voltage (Continued)											
EVCCR Reduction Rate per kWh (See Note 13)											
Summer EV Recharge Period										($0.00624)	
Winter EV Recharge Period										($0.00521)	
EVCCR Demand Reduction per kW (See Note 13)											
Summer On-Peak Period										($7.16)	
All Winter Hours										($0.82)	
Primary Distribution Voltage											
Basic Service Charge, per month										$123.90	
Consumption Charge per kWh											
Summer On-Peak Period	$0.11031	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00106	$0.18441	(R)
Summer Off-Peak Period	$0.01226	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00106	$0.08636	(R)
All Winter Hours	$0.00001	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00106	$0.07411	(R)
Demand Charge Per kW of Maximum Demand											
Summer On-Peak Period										$17.09	
All Winter Hours										$1.41	
Facilities Charge, Per kW of Maximum Demand										$5.20	
Additional Meter Charge per additional meter per month										$114.25	
EVCCR (Electric Vehicle Commercial Charging Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.01226	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00106	$0.08636	(R)
Winter EV Recharge Period	$0.00001	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00106	$0.07411	(R)
EVCCR BTGR Transition Rate per kWh (See Note 13)											
Summer On-Peak Period										$0.06882	
All Winter Hours										$0.00202	
EVCCR Reduction Rate per kWh (See Note 13)											
Summer EV Recharge Period										($0.00607)	
Winter EV Recharge Period										($0.00484)	
EVCCR Demand Reduction per kW (See Note 13)											
Summer On-Peak Period										($10.25)	
All Winter Hours										($0.85)	
Transmission Voltage											
Basic Service Charge, per month										$214.30	
Consumption Charge per kWh											
Summer On-Peak Period	$0.08874	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00077	$0.16255	(R)
Summer Off-Peak Period	$0.01800	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00077	$0.09181	(R)
All Winter Hours	$0.00386	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00077	$0.07767	(R)
Demand Charge, Per kW of Maximum Demand											
Summer On-Peak Period										$12.42	
All Winter Hours										$1.04	
Facilities Charge per dollar of Utility Investment										$0.00262	
Facilities Charge per dollar of Contributed Investment										$0.00073	
Or, Facilities Charge, Per kW of Maximum Demand										$1.60	
HVD Charge, Per kW of Maxim **9/27/2023**										$0.02	
Additional Meter Charge per additional meter per month										$177.25	

(Continued)

Issued: **11-15-23**	**Issued By:**	
Effective: **01-01-24**	**Janet Wells**	
Notice No.: Advice No.: **23-04(E)**	**Vice President, Regulatory**	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

29 th Revised PUCN Sheet No. 63J(2)
Cancelling 28 th Revised PUCN Sheet No. 63J(2)

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates
(Continued)

				PUBLIC POLICY RATES							
Schedule Number & Type of Charge	**BTGR**	**BTER**	**DEAA**	**TRED**	**REPR**	**UEC**	**NDPP**	**ESAP**	**EE**	**Total Rate**	
GS-2 TOU - Medium General Service – Time-of-Use (Continued)											
EVCCR (Electric Vehicle Commercial Charging Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.01800	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00077	$0.09181	(R)
Winter EV Recharge Period	$0.00386	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00077	$0.07767	(R)
EVCCR BTGR Transition Rate per kWh (See Note 13)											
Summer On-Peak Period										$0.06326	
All Winter Hours										$0.00180	
EVCCR Reduction Rate per kWh (See Note 13)											
Summer EV Recharge Period										($0.00664)	
Winter EV Recharge Period										($0.00523)	
EVCCR Demand Reduction per kW (See Note 13)											
Summer On-Peak Period										($7.45)	
All Winter Hours										($0.62)	
GS-3 - Large General Service											
Secondary Distribution Voltage											
Basic Service Charge, per month										$536.60	
Consumption Charge per kWh											
Summer On-Peak Period	$0.09964	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00084	$0.17352	(R)
Summer Off-Peak Period	$0.01564	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00084	$0.08952	(R)
All Winter Hours	$0.00328	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00084	$0.07716	(R)
Demand Charge, Per kW of Maximum Demand											
Summer On-Peak Period										$13.62	
All Winter Hours										$1.46	
Facilities Charge, Per kW of Maximum Demand										$6.50	
Additional Meter Charge per additional meter per month										$22.25	
EVCCR (Electric Vehicle Commercial Charging Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.01564	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00084	$0.08952	(R)
Winter EV Recharge Period	$0.00328	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00084	$0.07716	(R)
EVCCR BTGR Transition Rate per kWh (See Note 13)											
Summer On-Peak Period										$0.06012	
All Winter Hours										$0.00172	
EVCCR Reduction Rate per kWh (See Note 13)											
Summer EV Recharge Period										($0.00641)	
Winter EV Recharge Period										($0.00517)	
EVCCR Demand Reduction per kW (See Note 13)											
Summer On-Peak Period										($8.17)	
All Winter Hours										($0.88)	
Primary Distribution Voltage											
Basic Service Charge, per month										$612.10	
Consumption Charge per kWh											
Summer On-Peak Period	$0.10072	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00068	$0.17444	(R)

(Continued)

Issued: **11-15-23**	**Issued By:**	
Effective: **01-01-24**	**Janet Wells**	
Notice No.: Advice No.: **23-04(E)**	**Vice President, Regulatory**	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

29 th Revised PUCN Sheet No. 63J(3)
Cancelling 28 th Revised PUCN Sheet No. 63J(3)

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates
(Continued)

				PUBLIC POLICY RATES							
Schedule Number & Type of Charge	**BTGR**	**BTER**	**DEAA**	**TRED**	**REPR**	**UEC**	**NDPP**	**ESAP**	**EE**	**Total Rate**	
GS-3 - Large General Service (Continued)											
Primary Distribution Voltage (Continued)											
Summer Off-Peak Period	$0.01654	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00068	$0.09026	(R)
All Winter Hours	$0.00160	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00068	$0.07532	(R)
Demand Charge Per kW of Maximum Demand											
Summer On-Peak Period										$14.55	
All Winter Hours										$1.64	
Facilities Charge, Per kW of Maximum Demand										$7.65	
Additional Meter Charge per additional meter per month										$127.00	
EVCCR (Electric Vehicle Commercial Charging Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.01654	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00068	$0.09026	(R)
Winter EV Recharge Period	$0.00160	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00068	$0.07532	(R)
EVCCR BTGR Transition Rate per kWh (See Note 13)											
Summer On-Peak Period										$0.05855	
All Winter Hours										$0.00180	
EVCCR Reduction Rate per kWh (See Note 13)											
Summer EV Recharge Period										($0.00650)	
Winter EV Recharge Period										($0.00500)	
EVCCR Demand Reduction per kW (See Note 13)											
Summer On-Peak Period										($8.73)	
All Winter Hours										($0.98)	
Transmission Voltage											
Basic Service Charge, per month										$653.70	
Consumption Charge per kWh											
Summer On-Peak Period	$0.10910	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00077	$0.18291	(R)
Summer Off-Peak Period	$0.01991	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00077	$0.09372	(R)
All Winter Hours	$0.00554	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00077	$0.07935	(R)
Demand Charge Per kW of Maximum Demand											
Summer On-Peak Period										$9.22	
All Winter Hours										$0.91	
Facilities Charge per dollar of Utility Investment										$0.00262	
Facilities Charge per dollar of Contributed Investment										$0.00073	
Or, Facilities Charge, Per kW of Maximum Demand										$1.60	
HVD Charge, Per kW of Maximum Demand										$0.01	
Additional Meter Charge per additional meter per month										$175.25	
EVCCR (Electric Vehicle Commercial Charging Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.01991	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00077	$0.09372	(R)
Winter EV Recharge Period	$0.00554	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00077	$0.07935	(R)
EVCCR BTGR Transition Rate per kWh (See Note 13)											
Summer On-Peak Period										$0.03006	
All Winter Hours										$0.00100	

(Continued)

Issued:	**11-15-23**	**Issued By:**
Effective:	**01-01-24**	**Janet Wells**
Notice No.: Advice No.:	**23-04(E)**	**Vice President, Regulatory**

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

89 th Revised	PUCN Sheet No. 63K
Cancelling 88 th Revised	PUCN Sheet No. 63K

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates
(Continued)

				PUBLIC POLICY RATES							
Schedule Number & Type of Charge	**BTGR**	**BTER**	**DEAA**	**TRED**	**REPR**	**UEC**	**NDPP**	**ESAP**	**EE**	**Total Rate**	
GS-3 - Large General Service (Continued)											
Transmission Voltage (Continued)											
EVCCR Reduction Rate per kWh (See Note 13)											
Summer EV Recharge Period										($0.00683)	
Winter EV Recharge Period										($0.00540)	
EVCCR Demand Reduction per kW (See Note 13)											
Summer On-Peak Period										($5.53)	
All Winter Hours										($0.55)	
WP - City of Elko Water Pumping											
Basic Service Charge, per month										$3,728.90	
Consumption Charge per kWh	$0.04701	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00122	$0.12127	(R)
IS-1 - Irrigation Service											
Basic Service Charge, per month										$31.50	
Consumption Charge per kWh	$0.06936	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00191	$0.14431	(R)
Additional Meter Charge per additional meter per month										$5.00	
IS-1 TOU - Irrigation Service											
Basic Service Charge, per month										$31.50	
Consumption Charge per kWh											
Summer On-Peak Period	$0.13869	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00191	$0.21364	(R)
Summer Off-Peak Period	$0.07511	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00191	$0.15006	(R)
All Winter Hours	$0.02406	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00191	$0.09901	(R)
Additional Meter Charge per additional meter per month										$5.00	
IS-2 - Interruptible Irrigation Service (See Note 15)											
Consumption Charge per kWh	$0.00000	$0.06751	$0.00000	$0.00000	$0.00000	$0.00039	$0.00074	$0.00002	$0.00000	$0.06866	
OGS-2-TOU - Optional Medium General Service Time-of-Use											
Secondary Distribution Voltage											
Basic Service Charge, per month										$27.60	
Consumption Charge per kWh											
Summer On-Peak Period	$0.08460	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00103	$0.15867	(R)
Summer Off-Peak Period	$0.01618	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00103	$0.09025	(R)
All Winter Hours	$0.00581	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00103	$0.07988	(R)
Demand Charge, Per kW of Maximum Demand											
Summer On-Peak Period										$9.15	
All Winter Hours										$0.81	
Facilities Charge, Per kW of Maximum Demand										$6.40	
Additional Meter Charge per additional meter per month										$12.25	
OGS-EVRR (General Service Electric Vehicle Recharge Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.00972	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00103	$0.08379	(R)
Winter EV Recharge Period	$0.00039	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00103	$0.07446	(R)
EVCCR (Electric Vehicle Commercial Charging Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.01618	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00103	$0.09025	(R)
Winter EV Recharge Period	$0.00581	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00103	$0.07988	(R)

(Continued)

Issued:	**11-15-23**	**Issued By:**	
Effective:	**01-01-24**	**Janet Wells**	
Notice No.: Advice No.:	**23-04(E)**	**Vice President, Regulatory**	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

69 th Revised PUCN Sheet No. 63K(1)
Cancelling 68 th Revised PUCN Sheet No. 63K(1)

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates
(Continued)

				PUBLIC POLICY RATES							
Schedule Number & Type of Charge	**BTGR**	**BTER**	**DEAA**	**TRED**	**REPR**	**UEC**	**NDPP**	**ESAP**	**EE**	**Total Rate**	
OGS-2-TOU - Optional Medium General Service Time-of-Use (Continued)											
Secondary Distribution Voltage (Continued)											
EVCCR BTGR Transition Rate per kWh (See Note 13)											
Summer On-Peak Period										$0.05560	
All Winter Hours										$0.00164	
EVCCR Reduction Rate per kWh (See Note 13)											
Summer EV Recharge Period										($0.00646)	
Winter EV Recharge Period										($0.00542)	
EVCCR Demand Reduction per kW (See Note 13)											
Summer On-Peak Period										($5.49)	
All Winter Hours										($0.49)	
Primary Distribution Voltage											
Basic Service Charge, per month										$74.40	
Consumption Charge per kWh											
Summer On-Peak Period	$0.08460	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00088	$0.15852	(R)
Summer Off-Peak Period	$0.01618	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00088	$0.09010	(R)
All Winter Hours	$0.00581	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00088	$0.07973	(R)
Demand Charge, Per kW of Maximum Demand											
Summer On-Peak Period										$9.68	
All Winter Hours										$0.87	
Facilities Charge, Per kW of Maximum Demand										$5.10	
Additional Meter Charge per additional meter per month										$103.00	
OGS-EVRR (General Service Electric Vehicle Recharge Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.00972	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00088	$0.08364	(R)
Winter EV Recharge Period	$0.00039	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00088	$0.07431	(R)
EVCCR (Electric Vehicle Commercial Charging Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.01618	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00088	$0.09010	(R)
Winter EV Recharge Period	$0.00581	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00088	$0.07973	(R)
EVCCR BTGR Transition Rate per kWh (See Note 13)											
Summer On-Peak Period										$0.05076	
All Winter Hours										$0.00349	
EVCCR Reduction Rate per kWh (See Note 13)											
Summer EV Recharge Period										($0.00646)	
Winter EV Recharge Period										($0.00542)	
EVCCR Demand Reduction per kW (See Note 13)											
Summer On-Peak Period										($5.81)	
All Winter Hours										($0.52)	
Transmission Voltage											
Basic Service Charge, per month										$82.50	
Consumption Charge per kWh											
Summer On-Peak Period	$0.08460	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00060	$0.15824	(R)
Summer Off-Peak Period	$0.01618	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00060	$0.08982	(R)
All Winter Hours	$0.00581	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00060	$0.07945	(R)

(Continued)

Issued:	**11-15-23**	**Issued By:**	
Effective:	**01-01-24**	**Janet Wells**	
Notice No.: Advice No.:	**23-04(E)**	**Vice President, Regulatory**	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

	67 th Revised	PUCN Sheet No. 63K(2)
Cancelling	66 th Revised	PUCN Sheet No. 63K(2)

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates
(Continued)

				PUBLIC POLICY RATES							
Schedule Number & Type of Charge	**BTGR**	**BTER**	**DEAA**	**TRED**	**REPR**	**UEC**	**NDPP**	**ESAP**	**EE**	**Total Rate**	
OGS-2-TOU - Optional Medium General Service Time-of-Use (Continued)											
Transmission Voltage (Continued)											
Demand Charge Per kW of Maximum Demand											
Summer On-Peak Period										$11.87	
All Winter Hours										$0.86	
Facilities Charge per dollar of Utility Investment										$0.00262	
Facilities Charge per dollar of Contributed Investment										$0.00073	
Or, Facilities Charge, Per kW of Maximum Demand										$1.60	
HVD Charge, Per kW of Maximum Demand										$0.01	
Additional Meter Charge per additional meter per month										$131.00	
OGS-EVRR (General Service Electric Vehicle Recharge Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.00972	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00060	$0.08336	(R)
Winter EV Recharge Period	$0.00039	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00060	$0.07403	(R)
EVCCR (Electric Vehicle Commercial Charging Rider)											
Consumption Charge per kWh											
Summer EV Recharge Period	$0.01618	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00060	$0.08982	(R)
Winter EV Recharge Period	$0.00581	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00060	$0.07945	(R)
EVCCR BTGR Transition Rate per kWh (See Note 13)											
Summer On-Peak Period										$0.05076	
All Winter Hours										$0.00349	
EVCCR Reduction Rate per kWh (See Note 13)											
Summer EV Recharge Period										($0.00646)	
Winter EV Recharge Period										($0.00542)	
EVCCR Demand Reduction per kW (See Note 13)											
Summer On-Peak Period										($7.12)	
All Winter Hours										($0.52)	
GS-4 – Large Transmission Service											
Basic Service Charge, per month										$1,522.40	
Facilities Charge, (See Schedule GS-4), per dollar of Investment										$0.00311	
Tier 1 Rates (See Note 16)											
Demand Charge, for each kW of maximum billing demand											
Summer On-Peak Period										$17.99	
All Winter Hours										$1.91	
Consumption Charge per kWh											
Summer On-Peak Period	$0.09374	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00088	$0.16766	(R)
Summer Off-Peak Period	$0.01550	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00088	$0.08942	(R)
All Winter Hours	$0.00258	$0.06440	$0.00500	$0.00072	$0.00177	$0.00039	$0.00074	$0.00002	$0.00088	$0.07650	(R)
Additional Meter Charge per additional meter per month										$214.50	
Tier 2 Rates (reserved for future use)											

(Continued)

Issued:	**11-15-23**	**Issued By:**	
Effective:	**01-01-24**	**Janet Wells**	
Notice No.: Advice No.:	**23-04(E)**	**Vice President, Regulatory**	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road
Reno, NV 89511
Tariff No. Electric No. 1

69 th Revised PUCN Sheet No. 63L
Cancelling 68 th Revised PUCN Sheet No. 63L

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SIERRA PACIFIC POWER COMPANY
ELECTRIC SCHEDULES
Bundled Rates
(Continued)

				PUBLIC POLICY RATES							
Schedule Number & Type of Charge	**BTGR**	**BTER**	**DEAA**	**TRED**	**REPR**	**UEC**	**NDPP**	**ESAP**	**EE**	**Total Rate**	
WCS - Wireless Communication Service											
Basic Service Charge, per month										$6.70	
Consumption Charge per month, per installed device											
(rate includes UEC):											
Level 1										$5.92	(R)
Level 2										$11.81	(R)
Level 3										$17.72	(R)
NGR – Optional NV GreenEnergy Rider											
(in addition to other rates and assessments paid by the Customer)											
Consumption Charge per kWh											
Existing Renewable Resource Rate										$0.00103	
ESER - Expanded Solar Energy Rate											
(in addition to other rates and assessments paid by the Customer)											
Consumption Charge per kWh											
ESER (see note 10)										$0.05645	(R)
ESER LID (see note 11)										$0.05645	(R)

Notes
1. The charges shown above are subject to adjustments for taxes and assessments as specified in the Tax Adjustment Rider (PUCN Sheet No. 63E) and Schedule MC (PUCN Sheet Nos. 63C-63D.)
2. BTGR = Base Tariff General Rate
3. BTER = Base Tariff Energy Rate
4. TRED = Temporary Renewable Energy Development Charge.
5. REPR = Renewable Energy Program Rate (see Schedule REPR, PUCN Sheet No. 63B).
6. UEC = Universal Energy Charge (see Special Condition 1 of the applicable rate schedule).
7. DEAA = Deferred Energy Accounting Adjustment (see Schedule DEAA, PUCN Sheet No. 63).
8. NDPP = Natural Disaster Protection Plan Rate (see Schedule NDPP, PUCN Sheet No. 80S).
9. ESAP = Expanded Solar Access Program Rate (see Schedule ESAP, PUCN Sheet No. 81AZ(2)).
10. ESER = Expanded Solar Energy Rate (see Schedule ESER, PUCN Sheet Nos. 81AZ-81AZ(1)).
11. ESER LID = Expanded Solar Energy Rate Low Income Discount Rate (see Schedule ESER, PUCN Sheet Nos. 81AZ-81AZ(1)).
12. The Excess Energy Credit is determined by the appropriate NMR Rider - NMR-G and NMR-405. See pages 63H(1) and 63I for the appropriate credit by Rate Class Rider.
13. Customers on EVCCR-TOU rider are subject to EVCCR BTGR Transition Rate and shall be credited with EVCCR Reduction Rate and EVCCR Demand Rate Reduction.
14. Time-of-Use and Season periods are defined in the Special Conditions of the applicable rate schedule.
15. All rate schedules that contain a demand billing component are also subject to the Power Factor Adjustment charge (see the Special Conditions of the applicable rate schedule.)
16. For the billing periods November 1 through the end of February, the billing provisions of Schedule No. IS-1 are applicable.
17. Tier 1 rates for demand and consumption are applicable to that portion of Customer's load identified in the service agreement as tied to Tier 1 rates, subject to the Special Conditions of the GS-4 rate schedule.
18. HVD Charge not applicable to Customers that directly connect to FERC Transmission.
19. Other charges may apply, please see the applicable rate schedule.

(Continued)

Issued: **11-15-23**	**Issued By:**	
Effective: **01-01-24**	**Janet Wells**	
Notice No.: / Advice No.: **23-04(E)**	**Vice President, Regulatory**	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road, Reno, Nevada — **160th Revised** — PUCN Sheet No. **72**
Tariff No. **Electric No. 1** — Cancelling **159th Revised** — PUCN Sheet No. **72**

Schedule No. OLS
OUTDOOR LIGHTING SERVICE

APPLICABLE

To all classes of Customers for lighting outdoor areas other than public streets, alleys, roads and highways. Lighting service will be furnished from dusk-to-dawn by Utility-owned vertically mounted lamps supplied from Utility's 120/240 volt overhead and underground circuits and mounted on Utility-owned poles. This schedule is closed to new installations.

TERRITORY

Entire Nevada Service Area

RATES

The following rates will be charged per lamp, per month for energy, maintenance and facilities as listed below:

Bundled Service

Class Codes	Lamp Type	Watts	kWh/Mo	Overhead/ Multi-Use Pole	Overhead/ Light Only/ Wood Pole	Overhead/ Light Only/ Other Pole	Underground/ Light Only/ Wood Pole	Underground/ Light Only/ Other Pole	
	Mercury Vapor: (Rate Codes)			(007)	(009)	(011)	(013)	(015)	
(17)	175 W	206	71	$17.18	$26.13	$40.95	$34.29	$39.00	(R)
(21)	400 W	455	157	29.97	40.61	49.86	48.77	46.30	(R)
	High Pressure Sodium: (Rate Codes)			(001)	(003)	(005)	(033)	(035)	
(31)	70 W	84	29	12.62	21.57	32.34	33.43	34.43	(R)
(32)	100 W	118	41	13.97	22.92	33.69	34.78	35.78	(R)
(33)	150 W	194	67	16.74	25.69	36.46	33.85	38.57	(R)
	200 W	229	79	N/A	32.93	N/A	N/A	N/A	(R)
	Light Emitting Diode (LED): (Rate Codes)			(001)	(003)	(005)	(033)	(035)	
		51	18	14.78	25.79	32.07	34.52	34.72	(R)

Additional Services:

(37)	Additional Wood Pole	$20.43
(38)	Additional Other Pole	$13.36
(39)	Additional 130 Ft. Underground	$6.37

The above rates include a Base Tariff Energy Rate (BTER) of $0.06440 per kWh, a Temporary Renewable Energy Development Charge (TRED) of $0.00072 per kWh, an Energy Efficiency Charge (EE) of $0.00079 per kWh, a Renewable Energy Program Rate (REPR) of $0.00177 per kWh, a Deferred Energy Accounting Adjustment (see Schedule DEAA) and a Natural Disaster Protection Plan Rate (NDPP) of $0.00074 per kWh, and the Expanded Solar Access Program Rate (ESAP) of $0.00002 per kWh, multiplied by the monthly kWh shown, for each lamp. (R)

(Continued)

Issued: **11-15-23** Effective: **01-01-24** Notice No: **23-04(E)** Advice No.:	Issued By: Janet Wells Vice President, Regulatory	

SIERRA PACIFIC POWER COMPANY dba NV Energy
6100 Neil Road, Reno, Nevada — **125th Revised** PUCN Sheet No. **75A**
Tariff No. **Electric No. 1** Cancelling **124th Revised** PUCN Sheet No. **75A**

Schedule No. SL
STREET LIGHTING SERVICE
(Continued)

RATES (Continued)

Bundled Service

Lamp Type	kWh/ Mo.	Multi-use Pole	Light Only/ Wood Pole	Light Only/ Other Pole	Service to Customer-Owned Lamps Non-metered	
Mercury Vapor:						
175W	67	$12.68	$16.20	$19.68	N/A	(R)
High Pressure Sodium:						
70W	29	$8.61	$12.14	$15.62	N/A	(R)
100W	41	9.90	13.42	16.90	$4.40	(R)
150W	59	12.02	17.04	19.01	6.31	(R)
200W	79	14.18	19.20	21.17	8.47	(R)
Light Emitting Diode (LED):						
Small	12	$8.09	$12.33	$12.94	$1.29	(R)
Decorative	24	2.58	N/A	24.74	2.58	(R)
Medium	26	11.62	17.38	15.00	2.79	(R)
Large	40	13.62	19.92	20.45	4.29	(R)

The above rates include a Base Tariff Energy Rate (BTER) of $0.06440 per kWh, a Temporary Renewable Energy Development Charge (TRED) of $0.00072 per kWh, an Energy Efficiency Charge (EE) of $0.00063 per kWh, a Renewable Energy Program Rate (REPR) of $0.00177 per kWh, a Deferred Energy Accounting Adjustment Rate (see Schedule DEAA), a Natural Disaster Protection Plan Rate (NDPP) of $0.00074 per kWh, and the Expanded Solar Access Program Rate (ESAP) of $0.00002 per kWh multiplied by the monthly kWh shown, for each lamp. (R)

Late Charge
The Utility may charge a fee as set forth in Schedule MC for the late payment of a bill.

Tax Adjustment Charge:
The charges shown above are subject to adjustments for taxes and assessments as specified in the Tax Adjustment Rider (PUCN Sheet No. 63E).

Universal Energy Charge (UEC)
All kWh Per kWh $0.00039

(Continued)

Issued: **11-15-23** Effective: **01-01-24** Notice No.: **23-04(E)** Advice No.:	Issued By: Janet Wells Vice President, Regulatory	

EXHIBIT C

SIERRA PACIFIC POWER COMPANY
d/b/a NV Energy
CONSOLIDATED BALANCE SHEET
AS OF DECEMBER 31, 2023 AND 2022
(IN THOUSANDS)

Ln No	(a) Assets and Other Debits	(b) As Recorded December 31, 2023	(c) As Recorded December 31, 2022	Ln No
1	Utility Plant			1
2	Utility Plant (101-106,114,118)	$ 5,704,287	$ 5,465,773	2
3	Construction Work in Progress (107)	325,909	235,661	3
4	Total Utility Plant	6,030,196	5,701,434	4
5				5
6	Less: Accumulated Prov for Depr and Amort (108, 111, 115, 119)	(2,294,488)	(2,185,256)	6
7	Net Utility Plant	3,735,708	3,516,178	7
8				8
9	Utility Plant Adjustment (116)	-	-	9
10				10
11	Other Investments (121-128)	69,399	57,741	11
12				12
13	Current and Accrued Assets			13
14	Cash and Cash Equivalents (131-136)	44,457	48,835	14
15	Notes and Accounts Receivable (Less Accumulated Provision			15
16	for Uncollectible Accounts) (141-146, 171-173)	188,416	199,052	16
17	Materials, Supplies and Fuel (151, 154, 163, 164)	116,991	78,602	17
18	Prepayments (165)	16,400	9,620	18
19	MTM Asset Value (175.7)	91	7,984	19
20	Total Current and Accrued Assets	366,355	344,093	20
21				21
22	Deferred Debits			22
23	Unamortized Debt Expense (181)	7,812	7,766	23
24	Deferred Energy - Electric (182.3, 182.4)	57,264	223,996	24
25	Deferred Energy - Gas (191)	19,423	52,988	25
26	Other Regulatory Assets (182)	290,839	299,849	26
27	Preliminary Survey (183)	5,344	2,651	27
28	Clearing Accounts (184)	177	(148)	28
29	Miscellaneous Deferred Debits (186)	66,811	74,078	29
30	Unamortized Loss on Reacquired Debt (189)	11,269	12,360	30
31	Accumulated Deferred Income Taxes (190)	290,394	298,587	31
32	Total Deferred Debits	749,333	972,127	32
33				33
34	Total Assets and Other Debits	$ 4,920,795	$ 4,890,139	34

SIERRA PACIFIC POWER COMPANY
d/b/a NV Energy
CONSOLIDATED BALANCE SHEET
AS OF DECEMBER 31, 2023 AND 2022
(IN THOUSANDS)

Ln No	(a) Capitalization and Liabilities	(b) As Recorded December 31, 2023	(c) As Recorded December 31, 2022	Ln No
1	Capitalization			1
2	Common Shareholders Equity (201, 207, 211, 214, 215, 216)	$ 2,066,055	$ 2,048,591	2
3	Long Term Debt (221, 223, 224, 225, 226)	1,299,939	905,561	3
4	Accumulated Other Comprehensive Income (219)	(690)	(596)	4
5	Total Capitalization	3,365,304	2,953,556	5
6				6
7	Other Non-Current Liabilities			7
8	Operating and Finance Leases (227)	108,238	114,212	8
9	Accrued Retirement Benefits (228.3)	6,623	8,490	9
10	MTM Liability Value Deferred (244.7)	356	7,008	10
11	Asset Retirement Obligations (230)	12,569	11,143	11
12	Other (228.2,229)	4,095	4,473	12
13	Total Other Non-Current Liabilities	131,881	145,326	13
14				14
15	Current and Accrued Liabilities			15
16	Notes Payable (231)	-	70,000	16
17	Current Maturity Long Term Debt and Leases (229.4, 243)	9,251	258,780	17
18	Accounts Payable (232-234, 241)	244,228	238,543	18
19	Customer Deposits (235)	21,171	17,527	19
20	Accrued Taxes (236)	8,140	2,844	20
21	Accrued Interest (237)	17,909	13,960	21
22	MTM Liability Value - current (244.75)	15,750	14,398	22
23	Other Current and Accrued Liabilities (242)	14,396	15,385	23
24	Total Current and Accrued Liabilities	330,845	631,437	24
25				25
26	Deferred Credits			26
27	Accumulated Deferred Federal Income Taxes (282-283)	692,870	741,033	27
28	Accumulated Deferred Investment Tax Credits (255)	1,191	568	28
29	Regulatory Liabilities (254)	295,389	304,393	29
30	Deferred Energy - Electric (254.3)	-	-	30
31	Risk Management Regulatory Liabilities (254)	91	7,984	31
32	Customer Advances for Construction (252)	35,990	35,403	32
33	Other Deferred Credits (253, 257)	67,234	70,439	33
34	Total Deferred Credits	1,092,765	1,159,820	34
35				35
36	Total Capitalization and Liabilities	$ 4,920,795	$ 4,890,139	36

EXHIBIT C
PAGE 1 OF 1
PETTINARI

SIERRA PACIFIC POWER COMPANY
CONSOLIDATED INCOME STATEMENT
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023
(IN THOUSANDS)

Line No	(a) Description	(b) Electric	(c) Gas	(d)	(e) Total	Line No
1	Utility Operating Income					1
2	Operating Revenue (400)	$ 1,228,843	$ 245,164		$ 1,474,007	2
3						3
4	Operating Expenses					4
5	Operation Expense (401)	852,179	203,183		1,055,362	5
6	Maintenance Expense (402)	32,830	1,987		34,817	6
7	Depreciation and Amortization Exp (403-407)	183,661	17,152		200,813	7
8	Taxes Other Than Income Taxes (408)	27,311	3,234		30,545	8
9	Income Taxes - Federal (409.1)	57,498	10,323		67,821	9
10	Provision for Deferred Income Taxes (410.1, 411.1)	(49,110)	(6,728)		(55,838)	10
11	Investment Tax Credit Adjustment - Net (411.4)	667	(39)		628	11
12	Total Utility Operating Expense	1,105,036	229,112		1,334,148	12
13						13
14	Net Utility Operating Income	$ 123,807	$ 16,052		$ 139,859	14
15						15
16	Other Income and Deductions					16
17	Other Income					17
18	Non-Utility Operating Income (417)			$ 625		18
19	Interest and Dividend Income (419)			22,341		19
20	Allowance for Other Funds Used During					20
21	Construction (419.1)			13,995		21
22	Miscellaneous Non-operating Income (421)			1,232		22
23	Total Other Income			38,193		23
24						24
25	Other Income Deductions					25
26	Miscellaneous Income Deductions (426)			5,939		26
27	Total Other Income Deductions			5,939		27
28						28
29	Taxes Applicable to Other Income and Deductions					29
30	Taxes - Other than Income Taxes (408.2)			190		30
31	Income Taxes - Federal/State (409.2)			3,735		31
32	Provision for Deferred Income Taxes (410.2, 411.2)			-		32
33	Investment Tax Credit Adjustment (411.5)			(5)		33
34	Total Taxes on Other Income and Deductions			3,920		34
35						35
36	Total Other Income and Deductions				$ 28,334	36
37						37
38	Interest Charges					38
39	Interest on Long-Term debt (427)			51,324		39
40	Amortization of Debt Discount and Expense (428)			1,405		40
41	Amortization of Loss/Gain on Reacquired Debt (428.1, 429.1)			1,082		41
42	Amortization of Premium on Debt - Credit (429)			(291)		42
43	Interest on Debt to Associated Companies (430)			1,194		43
44	Other Interest Expense (431)			3,042		44
45						45
46	Total Interest Charges			57,756		46
47						47
48	Allowance for Borrowed Funds Used During					48
49	Construction - Credit (432)			(7,027)		49
50						50
51	Net Interest Charges				$ 50,729	51
52						52
53	Net Income				$ 117,464	53

EXHIBIT D

Sierra Pacific Power Company
d/b/a NV Energy
Electric Department
Summary Of Deferred Energy Account
At December 31, 2023

	(a)	(b)	(c)	
Ln	Description	Exhibit Reference	Total	Ln
1				1
2	Deferred Energy Balance at December 31, 2023	Page 2, Col (n), Ln 40	$ 56,827,863	2
3				3
4	kWh Sales (Billed & Unbilled)	Page 3, Col (n), Ln 6	8,247,015,698	4
5				5

EXHIBIT D-1

Sierra Pacific Power Company
d/b/a NV Energy
Electric Department - Nevada
Deferred Energy Balancing Account
At December 31, 2023

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
Ln	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Ln
1															1
2	Beginning Balance	$ 223,996,195	$ 209,769,267	$ 188,767,751	$ 159,002,358	$ 124,450,133	$ 90,294,004	$ 83,000,365	$ 99,844,943	$ 116,023,950	$ 113,499,441	$ 93,381,148	$ 74,434,358	$ 223,996,195	2
3	Adjustments	-	-	-	-	-	-	-	(152,832)	-	(1,540,275)	-	(27,019)	(1,720,126)	3
4	Allocated Fuel & Pur Pwr excl NGR	40,060,901	26,300,147	19,965,071	17,722,333	21,164,337	47,747,558	76,078,074	74,245,586	41,125,971	23,716,227	27,725,122	31,354,861	447,206,190	4
5	NGR Option 2 Cost	1,366,507	1,697,781	2,159,239	3,019,951	3,116,409	3,016,738	3,153,099	2,533,456	2,264,427	2,258,750	1,647,797	1,316,571	27,550,728	5
6	BTER Revenue	(49,286,462)	(44,621,290)	(46,846,307)	(46,482,438)	(47,733,802)	(48,342,958)	(62,003,300)	(58,877,293)	(49,260,307)	(43,278,261)	(46,884,358)	(48,394,670)	(592,011,445)	6
7	EDRR Revenue	255,671	249,426	201,150	296,484	255,799	281,856	259,572	286,272	277,326	239,814	265,344	241,159	3,109,872	7
8	ESAP Revenue	-	-	-	-	-	-	14,461	13,498	10,141	8,492	12,437	11,623	70,653	8
9	NGR Revenue	4,158,778	3,242,810	2,900,504	510,166	(1,183,555)	(123,158)	(170,257)	(237,515)	(180,275)	(175,502)	(154,475)	(132,628)	8,454,893	9
10	TRED Disbursement	(89,643)	(220,697)	(286,405)	(800,738)	(893,219)	(855,543)	(1,010,394)	(582,817)	(580,021)	(523,530)	(229,919)	(109,365)	(6,182,292)	10
11															11
12	Deferred Energy Costs	(3,534,248)	(13,351,822)	(21,906,748)	(25,734,242)	(25,274,031)	1,724,493	16,321,255	17,228,356	(6,342,737)	(19,294,284)	(17,618,052)	(15,739,468)	(113,521,527)	12
13															13
14	DEAA Cost Recovery Current	(9,395,114)	(8,497,303)	(8,929,014)	(9,571,024)	(9,740,454)	(9,795,336)	(53,504)	(1,154)	(12,039)	(1,521,018)	(1,696,076)	(1,750,064)	(60,962,099)	14
15	Deferred Income Tax - TRED	97,257	61,954	46,926	(64,383)	(91,212)	(80,307)	(116,039)	20,445	(27,922)	14,417	45,290	88,663	(4,910)	15
16															16
17	Adjustments														17
18	Deferred Energy Costs[5]	(2,568,514)	(295,630)	94,356	61,198	379,089	398,928	241,103	(1,610,601)	3,275,384	163,792	(90,935)	(520,114)	(471,943)	18
19	ESAP Discounts	(3,904)	(670)	(15,045)	(13,296)	(12,513)	(11,880)	(14,461)	(13,498)	(10,141)	(8,492)	(12,437)	(11,623)	(127,961)	19
20	Carrying Charge	-	-	-	-	-	-	-	-	-	-	-	-	-	20
21	Total Adjustments	(2,572,418)	(296,300)	79,311	47,902	366,576	387,048	226,642	(1,624,099)	3,265,243	155,300	(103,372)	(531,737)	(599,904)	21
22															22
23	Subtotal	208,591,673	187,685,795	158,058,226	123,680,611	89,711,013	82,529,902	99,378,720	115,468,489	112,906,495	92,853,855	74,008,938	56,501,753	48,907,755	23
24															24
25	Average Balance	216,293,934	198,727,531	173,412,988	141,341,484	107,080,573	86,411,953	91,189,542	107,580,300	114,465,223	102,406,510	83,695,043	65,454,546		25
26															26
27	Less Rate of Return (ROR) Adjustment [3]	-	-	-	-	-	-	-	-	-	-	-	-		27
28															28
29	Subtotal	216,293,934	198,727,531	173,412,988	141,341,484	107,080,573	86,411,953	91,189,542	107,580,300	114,465,223	102,406,510	83,695,043	65,454,546		29
30															30
31	Deferred Taxes [1]	(45,421,726)	(41,732,782)	(36,416,727)	(29,681,712)	(22,486,920)	(18,146,510)	(19,149,804)	(22,591,863)	(24,037,697)	(21,505,367)	(17,575,959)	(13,745,455)		31
32															32
33	Subtotal to Calculate Carrying Ch	170,872,208	156,994,749	136,996,261	111,659,772	84,593,653	68,265,443	72,039,738	84,988,437	90,427,526	80,901,143	66,119,084	51,709,091		33
34															34
35	Carrying Charges [2]	1,177,594	1,081,955	944,133	769,522	582,991	470,463	496,474	585,712	623,196	557,544	455,671	356,362	8,101,617	35
36															36
37	Carry Charge Disallowance Amrt [4]	-	-	-	-	-	-	(30,251)	(30,251)	(30,251)	(30,251)	(30,251)	(30,251)	(181,507)	37
38															38
39															39
40	G/L Ending Balance	$ 209,769,267	$ 188,767,751	$ 159,002,358	$ 124,450,133	$ 90,294,004	$ 83,000,365	$ 99,844,943	$ 116,023,950	$ 113,499,441	$ 93,381,148	$ 74,434,358	$ 56,827,863	$ 56,827,863	40
41														To: Pg 1, Col (c), Ln 2	41
42															42
43	[1] Federal Tax Rate	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%		43
44	[2] Carrying Charge Rate	8.27%	8.27%	8.27%	8.27%	8.27%	8.27%	8.27%	8.27%	8.27%	8.27%	8.27%	8.27%		44

45 [3] ROR Adjustment - NAC 704.150(3) applies when the average balance is a debit and the earned ROR is greater than authorized. 45

46 [4] Agreed upon from stipulation in Docket 23-05028, allocated according to balances as of June 30, 2023 46

47 [5] Error was discovered in October regarding monthly allocation true-up that affects July and August, carry charges and balance was corrected and updated in October. 47

Ln														Ln
48														48
49	Month	Sep-2022	Dec-2022	Dec-2022	Dec-2022	Mar-2023	Mar-2023	Mar-2023	Jun-2023	Jun-2023	Jun-2023	Sep-2023	Sep-2023	49
50	Earned ROR	5.62%	5.25%	5.25%	5.25%	4.96%	4.96%	4.96%	5.24%	5.24%	5.24%	5.40%	5.40%	50
51	Allowed ROR	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	51
52	Difference	-1.36%	-1.73%	-1.73%	-1.73%	-2.02%	-2.02%	-2.02%	-1.74%	-1.74%	-1.74%	-1.58%	-1.58%	52
53	Rate Base	$ 2,088,682,000	$ 2,143,859,000	$ 2,143,859,000	$ 2,143,859,000	$ 2,179,147,000	$ 2,179,147,000	$ 2,179,147,000	$ 2,179,312,000	$ 2,179,312,000	$ 2,179,312,000	$ 2,185,171,000	$ 2,185,171,000	53
54	ROR Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	54

EXHIBIT D-2

Exhibit D-2
Page 1 of 1
Ahlstedt

Sierra Pacific Power Company
d/b/a NV Energy
Electric Department - Nevada
kWh Sales - Billed And Unbilled
For The Twelve Months Ended December 31, 2023

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
Ln	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Ln
1															1
2	Nevada Sales														2
3	Nevada Total	740,256,940	664,552,130	697,585,976	635,866,682	651,753,415	659,789,144	838,982,768	791,781,427	664,300,363	623,699,087	678,588,000	700,416,494	8,347,572,426	3
4	Less:														4
5	IS-2	(165,637)	(6,514)	259,190	4,521,870	13,622,680	18,501,164	24,858,308	21,586,645	14,643,306	3,680,585	(890,818)	(54,051)	100,556,728	5
6	Nevada Subject to DEAA (Ln:	740,422,577	664,558,644	697,326,786	631,344,812	638,130,735	641,287,980	814,124,460	770,194,782	649,657,057	620,018,502	679,478,818	700,470,545	**8,247,015,698**	6
7														To: Pg 1, Col (c), Ln 4	7
8	FERC Sales														8
9	FERC-California	85,265,663	60,549,410	53,748,270	47,200,650	26,340,697	14,330,528	22,809,776	34,570,704	23,827,453	26,634,427	35,435,759	62,320,572	493,033,909	9
10	FERC-Other	689,585	696,282	664,930	582,518	584,583	620,190	613,964	753,440	684,268	607,901	612,200	645,289	7,755,150	10
11	FERC-Total	85,955,248	61,245,692	54,413,200	47,783,168	26,925,280	14,950,718	23,423,740	35,324,144	24,511,721	27,242,328	36,047,959	62,965,861	500,789,059	11
12															12
13	Total System Sales (Ln3 + Ln1:	826,212,188	725,797,822	751,999,176	683,649,850	678,678,695	674,739,862	862,406,508	827,105,571	688,812,084	650,941,415	714,635,959	763,382,355	8,848,361,485	13
14															14
15	Off-System Sales	6,130,625	6,038,349	15,981,849	24,663,713	5,204,030	11,731,217	59,636,564	11,123,291	(40,709,078)	13,485,481	6,793,156	5,052,868	125,132,065	15
16															16
17	Grand Total Sales (Ln14 + Ln16	832,342,813	731,836,171	767,981,025	708,313,563	683,882,725	686,471,079	922,043,072	838,228,862	648,103,006	664,426,896	721,429,115	768,435,223	8,973,493,550	17

EXHIBIT E-1

SIERRA PACIFIC POWER COMPANY
RECORDED FUEL COSTS - BY STATION
FOR THE YEAR ENDED DECEMBER 31, 2023

Line No.	(a) Description	(b) Recorded Cost	(c) Units Used	(d) Units	(e) Reference	Line No.
1	Valmy					1
2	Coal	$ 60,729,592	535,407	Tons	E-1.1 Pg. 1	2
3	Diesel	$ 1,704,164	457,168	Gallons	E-1.2 Pg. 1	3
4						4
5	Diesels	$ 6,636	2,864	Gallons	E-1.3 Pg. 1	5
6						6
7	Fort Churchill					7
8	Natural Gas	$ 24,029,703	5,069,875	MMBTU	E-1.4 Pg. 2	8
9						9
10	Tracy					10
11	Natural Gas	$ 120,956,442	25,985,579	MMBTU	E-1.4 Pg. 2	11
12						12
13	Clark Mountain					13
14	Natural Gas	$ 5,522,012	1,652,727	MMBTU	E-1.4 Pg. 2	14
15						15
16	Pinon Pine					16
17	Natural Gas	$ 17,554,423	3,266,418	MMBTU	E-1.4 Pg. 2	17
18						18
19						19
20		**$ 230,502,972**				20

SIERRA PACIFIC POWER COMPANY
VALMY
COAL TRANSACTIONS (TONS)
FOR THE YEAR ENDED DECEMBER 31, 2023

Exhibit E-1.1
Page 1 of 1
PETTINARI

Line No.	(a) Description	(b) 2023 January	(c) 2023 February	(d) 2023 March	(e) 2023 April	(f) 2023 May	(g) 2023 June	(h) 2023 July	(i) 2023 August	(j) 2023 September	(k) 2023 October	(l) 2023 November	(m) 2023 December	(n) Total	Line No.
1	**Beginning Inventory (Tons)**	**112,675**	**132,898**	**123,940**	**72,232**	**47,294**	**97,261**	**179,924**	**129,043**	**106,423**	**129,236**	**117,198**	**138,485**	**112,675**	1
2															2
3	**Purchased**														3
4	West Elk	48,694	24,281			11,976	22,707				11,614	23,970	35,197	178,438	4
5	Skyline													-	5
6	Black Butte	12,052												12,052	6
7	Sufco													-	7
8	Kemmerer			5,231	23,006	44,595	32,501					11,567	21,806		8
9	Spring Creek					10,467	41,996	20,931	21,148	31,532	31,193	31,414	31,802		9
10	20 Mile					10,807	12,124		12,194	23,843					10
11	BTU Prior Adjustment													-	11
12	BTU Current Adjustment	411	223	1,247	331	(216)	(881)	(900)	(251)	(298)	(852)	(1,242)	185	(2,244)	12
13		61,157	24,503	6,478	23,337	77,630	108,445	20,031	33,090	55,078	41,955	65,709	88,990	188,245	13
14															14
15	**Used**														15
16	Burn	(39,363)	(33,461)	(58,185)	(48,276)	(27,662)	(25,782)	(70,912)	(55,709)	(32,264)	(53,994)	(44,422)	(43,804)	(533,835)	16
17	True-up	(1,572)												(1,572)	17
18	Inv Adjustment												-	-	18
19	Rounding													-	19
20		(40,935)	(33,461)	(58,185)	(48,276)	(27,662)	(25,782)	(70,912)	(55,709)	(32,264)	(53,994)	(44,422)	(43,804)	(535,407)	20
21															21
22	**Ending Inventory (Tons)**	**132,898**	**123,940**	**72,232**	**47,294**	**97,261**	**179,924**	**129,043**	**106,423**	**129,236**	**117,198**	**138,485**	**183,670**	**(234,486)**	22
23															23
24															24
25	**Fuel Costs**														25
26	Burn	$ 2,805,400	$ 2,384,773	$ 4,156,164	$ 3,476,819	$ 2,187,524	$ 2,725,927	$ 8,215,186	$ 6,461,724	$ 4,313,419	$ 6,819,946	$ 5,416,334	$ 4,665,174	$ 53,628,389	26
27	True up	$ 221,565	$ (5,117)	$ (56,407)	$ 34,329	$ 340,827	$ 553,520	$ 151,117	$ 968	$ 453,474	$ (1)	$ 233,253	$ 26,209	$ 1,953,737	27
28	Coal Handling	$ 412,838	$ 297,081	$ 472,831	$ 391,220	$ 368,950	$ 535,250	$ 713,723	$ 326,893	$ 356,718	$ 331,678	$ 387,297	$ 552,989	$ 5,147,466	28
29	Inv Adjustment													$ -	29
30		**$ 3,439,802**	**$ 2,676,738**	**$ 4,572,588**	**$ 3,902,368**	**$ 2,897,300**	**$ 3,814,696**	**$ 9,080,027**	**$ 6,789,585**	**$ 5,123,611**	**$ 7,151,623**	**$ 6,036,883**	**$ 5,244,371**	**$ 60,729,592**	30
31															31
32															32
33	**Average Unit Cost**	**$ 84.032**	**$ 79.995**	**$ 78.587**	**$ 80.835**	**$ 104.739**	**$ 147.958**	**$ 128.046**	**$ 121.875**	**$ 158.801**	**$ 132.453**	**$ 135.900**	**$ 119.723**	**$ 113.427**	33

SIERRA PACIFIC POWER COMPANY
VALMY
DIESEL TRANSACTIONS
FOR THE YEAR ENDED DECEMBER 31, 2023

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Line No.	(a) Description	(b) 2023 January	(c) 2023 February	(d) 2023 March	(e) 2023 April	(f) 2023 May	(g) 2023 June	(h) 2023 July	(i) 2023 August	(j) 2023 September	(k) 2023 October	(l) 2023 November	(m) 2023 December	(n) Total	Line No.
1	**Beginning Inventory (Gallons)** *	**119,518**	**121,008**	**120,734**	**114,062**	**124,687**	**128,087**	**144,948**	**81,614**	**56,318**	**124,586**	**133,162**	**120,471**	**119,518**	1
2															2
3	**Purchased**														3
4	Flyers Energy													-	4
5	Thomas Petroleum	36,243	21,158	43,702	55,722	8,604	28,499	74,414	64,186	129,820	49,577	62,521	54,464	628,910	5
6	True Up						2,402							2,402	6
7		**36,243**	**21,158**	**43,702**	**55,722**	**8,604**	**30,901**	**74,414**	**64,186**	**129,820**	**49,577**	**62,521**	**54,464**	**631,312**	7
8															8
9	**Used**														9
10	Unit 1	(34,376)	(1,488)	(38,571)	(35,707)		(17,760)	(14,769)	(51,014)	(38,918)	(16,093)	(21,232)	(5,183)	(275,111)	10
11	Unit 2	(377)	(19,944)	(11,803)	(9,390)	(8,469)		(115,539)	(38,468)	(22,634)	(24,908)	(53,980)	(57,693)	(363,205)	11
12	Inv Adjustment					3,265	3,720	(7,440)						(455)	12
13	Usage by Unit	(34,753)	(21,432)	(50,374)	(45,097)	(5,204)	(14,040)	(137,748)	(89,482)	(61,552)	(41,001)	(75,212)	(62,876)	(638,771)	13
14															14
15	Current Months Estimated Burn -IPC	(188)	(9,972)	(5,902)	(4,695)	(4,235)	-	(57,770)	(19,234)	(11,317)	(12,454)	(26,990)	(28,847)	(181,602)	15
16	Current Months Estimated Burn -SPPC	(34,564)	(11,460)	(44,473)	(40,402)	(970)	(14,040)	(79,979)	(70,248)	(50,235)	(28,547)	(48,222)	(34,030)	(457,168)	16
17	Usage by Company	(34,753)	(21,432)	(50,374)	(45,097)	(5,204)	(14,040)	(137,748)	(89,482)	(61,552)	(41,001)	(75,212)	(62,876)	(638,771)	17
18	Rounding	-	-	-	-	-	-	-	-	-	-	-	-	-	18
19		**(34,753)**	**(21,432)**	**(50,374)**	**(45,097)**	**(5,204)**	**(14,040)**	**(137,748)**	**(89,482)**	**(61,552)**	**(41,001)**	**(75,212)**	**(62,876)**	**(638,771)**	19
20															20
21	**Ending Inventory (Gallons)**	**121,008**	**120,734**	**114,062**	**124,687**	**128,087**	**144,948**	**81,614**	**56,318**	**124,586**	**133,162**	**120,471**	**112,059**	**112,059**	21
22															22
23	**Fuel Costs - SPPC**														23
24	Burn	$ 150,069	$ 47,829	$ 178,689	$ 152,370	$ 19,338	$ 37,255	$ 242,659	$ 226,806	$ 209,689	$ 118,964	$ 193,594	$ 126,903	$ 1,704,164	24
25	Inv Adjustments													$ -	25
26		**$ 150,069**	**$ 47,829**	**$ 178,689**	**$ 152,370**	**$ 19,338**	**$ 37,255**	**$ 242,659**	**$ 226,806**	**$ 209,689**	**$ 118,964**	**$ 193,594**	**$ 126,903**	**$ 1,704,164**	26
27															27
28															28
29	**Average Unit Cost - SPPC**	**$ 4.342**	**$ 4.174**	**$ 4.018**	**$ 3.771**	**$ 19.947**	**$ 2.653**	**$ 3.034**	**$ 3.229**	**$ 4.174**	**$ 4.167**	**$ 4.015**	**$ 3.729**	**$ 3.728**	29

SIERRA PACIFIC POWER COMPANY
DIESEL TRANSACTIONS
FOR THE YEAR ENDED DECEMBER 31, 2023

Exhibit E-1.3
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
Line No.	Description	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	Total	Line No.
1	**Beginning Inventory (Gallons)**	**15,241**	**15,241**	**14,881**	**16,595**	**17,395**	**17,294**	**16,813**	**16,723**	**16,635**	**16,938**	**16,758**	**16,451**	**15,241**	1
2															2
3	**Purchased**			1,645	1,509					404				3,558	3
4														-	4
5															5
6	**Used**														6
7	Burn		(356)	(415)	(201)	(145)	(341)	(137)	(144)	(196)	(212)	(140)	(284)	(2,570)	7
8	Inventory Adjustment		(4)	484	(509)	44	(140)	47	55	95	31	(167)	(231)	(294)	8
9		**-**	**(361)**	**69**	**(710)**	**(101)**	**(480)**	**(90)**	**(89)**	**(101)**	**(180)**	**(307)**	**(515)**	**(2,864)**	9
10															10
11	**Ending Inventory (Gallons)**	**15,241**	**14,881**	**16,595**	**17,395**	**17,294**	**16,813**	**16,723**	**16,635**	**16,938**	**16,758**	**16,451**	**15,936**	**12,377**	11
12															12
13															13
14	**Fuel Costs**														14
15	Brunswick Burn		$ 815.27	$ 482.02	$ 473.28	$ 340.41	$ 466.21	$ 322.51	$ 339.23	$ 461.26	$ 498.24	$ 330.51	$ 483.87	$ 5,013	15
16	Inventory Adjustments		$ 15.61	$ (1,107.82)	$ 1,164.20	$ (102.94)	$ 328.71	$ (110.31)	$ (130.43)	$ (203.00)	$ (73.49)	$ 392.68	$ 543.62	$ 717	16
17	GOB Burn			$ 430.50	$ -		$ 301.77	$ -					$ 174.57	$ 907	17
18		**$ -**	**$ 830.88**	**$ (195.30)**	**$ 1,637.48**	**$ 237.47**	**$ 1,096.69**	**$ 212.20**	**$ 208.80**	**$ 258.26**	**$ 424.75**	**$ 723.19**	**$ 1,202.06**	**$ 6,636**	18
19															19
20															20
21	**Average Unit Cost**	**$ -**	**$ 2.304**	**$ -**	**$ 2.308**	**$ 2.356**	**$ 2.283**	**$ 2.356**	**$ 2.356**	**$ 2.568**	**$ 2.356**	**$ 2.356**	**$ 2.333**	**$ 2.317**	21
22															22
23															23
24	**FERC Fuel Cost Recon**														24
25	Brunswick	$ -	$ 830.88	$ (625.80)	$ 1,637.48	$ 237.47	$ 794.92	$ 212.20	$ 208.80	$ 258.26	$ 424.75	$ 723	$ 1,027	$ 5,730	25
26	GOB	$ -	$ -	$ 430.50	$ -	$ -	$ 301.77	$ -	$ -	$ -	$ -	$ -	$ 175	$ 907	26
27	**Total Costs**	**$ -**	**$ 830.88**	**$ (195.30)**	**$ 1,637.48**	**$ 237.47**	**$ 1,096.69**	**$ 212.20**	**$ 208.80**	**$ 258.26**	**$ 424.75**	**$ 723**	**$ 1,202**	**$ 6,636**	27

SIERRA PACIFIC POWER COMPANY
NATURAL GAS COSTS AND VOLUMES - POWER PLANTS
FOR THE YEAR ENDED DECEMBER 31, 2023

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Line No.	(a) Description	(b) 2023 January	(c) 2023 February	(d) 2023 March	(e) 2023 April	(f) 2023 May	(g) 2023 June	(h) 2023 July	(i) 2023 August	(j) 2023 September	(k) 2023 October	(l) 2023 November	(m) 2023 December	(n) Total	Line No.
1	Gas Purchased	$ 48,022,496	$ 15,783,401	$ 9,294,052	$ 7,357,454	$ 5,791,916	$ 5,066,128	$ 12,239,258	$ 11,501,714	$ 9,034,260	$ 9,636,620	$ 9,732,968	$ 10,999,849	$ 154,460,116	1
2	Gas Sales	$ (196,303)	$ (194,821)	$ (1,219,442)	$ (3,384,018)	$ (391,903)	$ (1,004,770)	$ (2,254,080)	$ (3,077,704)	$ (1,679,708)	$ (805,701)	$ (1,066,087)	$ (271,885)	$ (15,546,421)	2
3	**Net Gas Costs**	**$ 47,826,193**	**$ 15,588,581**	**$ 8,074,610**	**$ 3,973,436**	**$ 5,400,013**	**$ 4,061,357**	**$ 9,985,178**	**$ 8,424,010**	**$ 7,354,552**	**$ 8,830,919**	**$ 8,666,881**	**$ 10,727,964**	**$ 138,913,695**	3
4															4
5															5
6	**Pipeline Transportation Costs**														6
7	Northwest Pipeline	$ 353,927	$ 343,459	$ 372,168	$ 422,799	$ 582,523	$ 563,732	$ 711,973	$ 674,762	$ 634,199	$ 614,886	$ 414,970	$ 436,893	$ 6,126,291	7
8	Paiute Pipeline	$ 305,718	$ 326,648	$ 319,528	$ 333,556	$ 442,818	$ 442,818	$ 542,073	$ 522,521	$ 499,118	$ 468,072	$ 368,191	$ 374,726	$ 4,945,785	8
9	Gas Transmission Northwest Corp.	$ 478,593	$ 461,751	$ 500,347	$ 568,417	$ 446,412	$ 432,011	$ 545,614	$ 520,814	$ 486,013	$ 471,212	$ 557,891	$ 583,149	$ 6,052,223	9
10	Tuscarora Gas Transmission	$ 559,878	$ 598,052	$ 570,914	$ 670,204	$ 893,605	$ 893,605	$ 1,092,184	$ 1,042,540	$ 1,005,306	$ 1,171,250	$ 657,793	$ 670,204	$ 9,825,535	10
11	Transcanada Pipeline BC (Foothills)	$ 124,827	$ 135,316	$ 131,436	$ 154,454	$ 156,381	$ 161,707	$ 197,476	$ 182,029	$ 177,540	$ 163,145	$ 152,205	$ 158,375	$ 1,894,892	11
12	Nova Gas Transmission	$ 277,814	$ 314,766	$ 305,762	$ 359,337	$ 365,035	$ 377,468	$ 455,759	$ 420,109	$ 409,747	$ 376,470	$ 350,082	$ 349,069	$ 4,361,419	12
13	Capacity Release NOVA	$ -	$ -	$ -	$ -	$ (3,857)	$ (3,857)	$ (4,714)	$ (4,500)	$ (4,339)	$ (4,071)	$ -	$ -	$ (25,339)	13
14	Capacity Release Foothills	$ -	$ -	$ -	$ -	$ (1,676)	$ (1,676)	$ (2,048)	$ (1,955)	$ (1,885)	$ (1,769)	$ -	$ -	$ (11,009)	14
15		**$ 2,100,757**	**$ 2,179,992**	**$ 2,200,156**	**$ 2,508,767**	**$ 2,881,241**	**$ 2,865,808**	**$ 3,538,317**	**$ 3,356,319**	**$ 3,205,697**	**$ 3,259,195**	**$ 2,501,131**	**$ 2,572,416**	**$ 33,169,796**	15
16															16
17															17
18	**Gas Withdrawls / (Injections)**	$ (89,590)	$ (95,159)	$ (89,479)	$ (105,949)	$ (156,404)	$ (180,109)	$ (202,228)	$ (173,198)	$ (166,353)	$ (207,062)	$ (217,325)	$ (193,840)	$ (1,876,696)	18
19															19
20	**Amort of Prepaid Option Premiums**													$ -	20
21															21
22	**Other (Brokerage Fees, Cochrane)**	$ 2,114	$ 2,414	$ 2,445	$ 2,892	$ 3,750	$ 4,238	$ 5,189	$ 4,949	$ 3,609	$ 3,375	$ 2,386	$ 2,557	$ 39,919	22
23															23
24	**True-up of Prior Month Accruals**	$ (1,945,650)	$ (315,489)	$ 6,422	$ 27,470	$ 183,522	$ (43,322)	$ 763,939	$ (425,381)	$ (254,262)	$ (103,353)	$ (93,345)	$ 15,317	$ (2,184,134)	24
25															25
26	**Total Gas Costs**	**$ 47,893,824**	**$ 17,360,340**	**$ 10,194,154**	**$ 6,406,617**	**$ 8,312,122**	**$ 6,707,972**	**$ 14,090,395**	**$ 11,186,698**	**$ 10,143,243**	**$ 11,783,074**	**$ 10,859,727**	**$ 13,124,413**	**$ 168,062,580**	26
27															27
28															28
29	Volumes Used (MMBTU)	3,107,252	2,881,588	2,659,421	2,125,843	2,888,865	2,337,245	4,046,184	3,142,597	2,987,815	3,622,689	2,762,226	3,441,579	36,003,304	29
30	Net True-up of Prior Month MMBTU	(478)	(4,333)	477	(2,357)	34	56	(397)	(30,225)	2,655	(742)	5,891	715	(28,706)	30
31	**Total Volume**	**3,106,774**	**2,877,255**	**2,659,898**	**2,123,486**	**2,888,898**	**2,337,302**	**4,045,787**	**3,112,372**	**2,990,470**	**3,621,947**	**2,768,117**	**3,442,294**	**35,974,598.78**	31
32															32
33	**Average Unit Cost**	**$ 15.416**	**$ 6.034**	**$ 3.833**	**$ 3.017**	**$ 2.877**	**$ 2.870**	**$ 3.483**	**$ 3.594**	**$ 3.392**	**$ 3.253**	**$ 3.923**	**$ 3.813**	**$ 4.672**	33

SIERRA PACIFIC POWER COMPANY
NATURAL GAS COSTS AND VOLUME BY STATION - POWER PLANTS
FOR THE YEAR ENDED DECEMBER 31, 2023

Exhibit E-1.4
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
Line No.	Description	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	Total	Line No.
1	**Fort Churchill**														1
2	Volume (MMBTU)	486,629	337,086	390,618	413,834	357,901	242,711	545,654	507,710	303,440	466,518	412,736	605,038	5,069,875	2
3	Fuel Costs	$ 7,363,415	$ 2,022,452	$ 1,361,187	$ 1,246,891	$ 1,042,788	$ 695,699	$ 1,876,622	$ 1,949,054	$ 1,023,049	$ 1,520,462	$ 1,621,592	$ 2,306,491	$ 24,029,703	3
4	Cost per MMBTU	$ 15.131	$ 6.000	$ 3.485	$ 3.013	$ 2.914	$ 2.866	$ 3.439	$ 3.839	$ 3.372	$ 3.259	$ 3.929	$ 3.812	$ 4.740	4
5															5
6	**Tracy**														6
7	Volume (MMBTU)	2,194,531	2,160,632	1,935,131	1,546,660	2,385,160	1,828,542	2,930,018	2,310,337	2,252,565	2,288,786	1,920,307	2,232,910	25,985,579	7
8	Fuel Costs	$ 34,000,489	$ 13,049,364	$ 7,562,211	$ 4,666,289	$ 6,844,891	$ 5,245,966	$ 10,248,943	$ 8,213,087	$ 7,636,645	$ 7,433,731	$ 7,540,854	$ 8,513,970	$ 120,956,442	8
9	Cost per MMBTU	$ 15.493	$ 6.040	$ 3.908	$ 3.017	$ 2.870	$ 2.869	$ 3.498	$ 3.555	$ 3.390	$ 3.248	$ 3.927	$ 3.813	$ 4.655	9
10															10
11	**Clark Mtn.**														11
12	Volume (MMBTU)	11,199	14,081	45,569	59,210	145,836	227,227	248,989	171,774	123,305	441,068	21,772	142,695	1,652,727	12
13	Fuel Costs	$ 49,187	$ 85,334	$ 171,907	$ 178,268	$ 415,461	$ 654,167	$ 894,464	$ 607,202	$ 407,240	$ 1,443,031	$ 72,122	$ 543,628	$ 5,522,012	13
14	Cost per MMBTU	$ 4.392	$ 6.060	$ 3.772	$ 3.011	$ 2.849	$ 2.879	$ 3.592	$ 3.535	$ 3.303	$ 3.272	$ 3.313	$ 3.810	$ 3.341	14
15															15
16	**Pinon Pine**														16
17	Volume (MMBTU)	414,415	365,456	288,579	103,781	2	38,822	321,126	122,551	311,159	425,575	413,302	461,650	3,266,418	17
18	Fuel Costs	$ 6,480,733	$ 2,203,189	$ 1,098,850	$ 315,169	$ 8,981	$ 112,140	$ 1,070,366	$ 417,355	$ 1,076,309	$ 1,385,850	$ 1,625,158	$ 1,760,322	$ 17,554,423	18
19	Cost per MMBTU	$ 15.638	$ 6.029	$ 3.808	$ 3.037	$ 5,470.092	$ 2.889	$ 3.333	$ 3.406	$ 3.459	$ 3.256	$ 3.932	$ 3.813	$ 5.374	19
20															20
21	**Total**														21
22	**Volume (MMBTU)**	**3,106,774**	**2,877,255**	**2,659,898**	**2,123,486**	**2,888,898**	**2,337,302**	**4,045,787**	**3,112,372**	**2,990,470**	**3,621,947**	**2,768,117**	**3,442,294**	**35,974,599**	22
23	**Fuel Costs**	**$ 47,893,824**	**$ 17,360,340**	**$ 10,194,154**	**$ 6,406,617**	**$ 8,312,122**	**$ 6,707,972**	**$ 14,090,395**	**$ 11,186,698**	**$ 10,143,243**	**$ 11,783,074**	**$ 10,859,727**	**$ 13,124,411**	**$ 168,062,580**	23
24	**Cost per MMBTU**	**$ 15.416**	**$ 6.034**	**$ 3.833**	**$ 3.017**	**$ 2.877**	**$ 2.870**	**$ 3.483**	**$ 3.594**	**$ 3.392**	**$ 3.253**	**$ 3.923**	**$ 3.813**	**$ 4.672**	24

SIERRA PACIFIC POWER COMPANY
NATURAL GAS COSTS AND VOLUME - POWER PLANT
FOR THE YEAR ENDED DECEMBER 31, 2023

Line No.	(a)	(b) 2023 January MMBTU	(c) 2023 January Costs	(d) 2023 February MMBTU	(e) 2023 February Costs	(f) 2023 March MMBTU	(g) 2023 March Costs	(h) 2023 April MMBTU	(i) 2023 April Costs	(j) 2023 May MMBTU	(k) 2023 May Costs	(l) 2023 June MMBTU	(m) 2023 June Costs	Line No.
1	Gas Volume Purchased	3,116,469		2,917,406		2,903,188		2,973,847		3,086,649		2,825,979		1
2														2
3	Gas Volume Sales	(9,217)		(35,818)		(243,767)		(848,004)		(197,784)		(488,734)		3
4														4
5	Net Prior Month MMBTU True-Up	(478)		(4,333)		477		(2,357)		34		56		5
6														6
7	**Net Volume Purchased**	**3,106,774**		**2,877,255**		**2,659,898**		**2,123,486**		**2,888,898**		**2,337,302**		7
8														8
9														9
10	Gas Purchased		$ 48,022,496		$ 15,783,401		$ 9,294,052		$ 7,357,454		$ 5,791,916		$ 5,066,128	10
11														11
12	Gas Sales		$ (196,303)		$ (194,821)		$ (1,219,442)		$ (3,384,018)		$ (391,903)		$ (1,004,770)	12
13														13
14	Transportation													14
15	Northwest Pipeline		$ 353,927		$ 343,459		$ 372,168		$ 422,799		$ 582,523		$ 563,732	15
16	Paiute Pipeline		$ 305,718		$ 326,648		$ 319,528		$ 333,556		$ 442,818		$ 442,818	16
17	Gas Transmission Northwest Corp.		$ 478,593		$ 461,751		$ 500,347		$ 568,417		$ 446,412		$ 432,011	17
18	Tuscarora Gas Transmission		$ 559,878		$ 598,052		$ 570,914		$ 670,204		$ 893,605		$ 893,605	18
19	Transcanada Pipeline BC (Foothills)		$ 124,827		$ 135,316		$ 131,436		$ 154,454		$ 156,381		$ 161,707	19
20	Nova Gas Transmission		$ 277,814		$ 314,766		$ 305,762		$ 359,337		$ 365,035		$ 377,468	20
21	Capacity Release NOVA		$ -		$ -		$ -		$ -		$ (3,857)		$ (3,857)	21
22	Capacity Release Foothills		$ -		$ -		$ -		$ -		$ (1,676)		$ (1,676)	22
23														23
24	Gas Withdrawals/ (Injections)		$ (89,590)		$ (95,159)		$ (89,479)		$ (105,949)		$ (156,404)		$ (180,109)	24
25														25
26	Net Gas and Transportation		$ 49,837,360		$ 17,673,414		$ 10,185,287		$ 6,376,255		$ 8,124,850		$ 6,747,056	26
27														27
28	Other (Brokerage Fees, Cochrane Fuel Ext)		$ 2,114		$ 2,414		$ 2,445		$ 2,892		$ 3,750		$ 4,238	28
29														29
30	Amortization of Prepaid Options Premiums		$ -		$ -		$ -		$ -		$ -		$ -	30
31														31
32	True-up of Prior Month Accruals		$ (1,945,650)		$ (315,489)		$ 6,422		$ 27,470		$ 183,522		$ (43,322)	32
33														33
34	Net Other Costs		$ (1,943,535)		$ (313,074)		$ 8,867		$ 30,362		$ 187,271		$ (39,084)	34
35														35
36	**Total Gas Costs**		**$ 47,893,824**		**$ 17,360,340**		**$ 10,194,154**		**$ 6,406,617**		**$ 8,312,122**		**$ 6,707,972**	36
37														37
38	**Average Unit Cost**		**$ 15.416**		**$ 6.034**		**$ 3.833**		**$ 3.017**		**$ 2.877**		**$ 2.870**	38
39														39

SIERRA PACIFIC POWER COMPANY
NATURAL GAS COSTS AND VOLUME - POWER PLANT
FOR THE YEAR ENDED DECEMBER 31, 2023

	(a)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)	(aa)	
		2023		2023		2023		2023		2023		2023		Total		
Line No.		July		August		September		October		November		December				Line No.
		MMBTU	Costs	MMBTU	Costs	MMBTU	Costs	MMBTU	Costs	MMBTU	Costs	MMBTU	Costs	MMBTU	Costs	
1	Gas Volume Purchased	4,853,095		4,012,570		3,722,030		4,001,888		3,131,660		3,534,959		41,079,740		1
2																2
3	Gas Volume Sales	(806,911)		(869,973)		(734,215)		(379,199)		(369,434)		(93,380)		(5,076,435)		3
4																4
5	Net Prior Month MMBTU True-Up	(397)		(30,225)		2,655		(742)		5,891		715		(28,706)		5
6																6
7	**Net Volume Purchased**	**4,045,787**		**3,112,372**		**2,990,470**		**3,621,947**		**2,768,117**		**3,442,294**		**35,974,598.73**		7
8																8
9																9
10	Gas Purchased		$ 12,239,258		$ 11,501,714		$ 9,034,260		$ 9,636,620		$ 9,732,968		$ 10,999,849		$ 154,460,116	10
11																11
12	Gas Sales		$ (2,254,080)		$ (3,077,704)		$ (1,679,708)		$ (805,701)		$ (1,066,087)		$ (271,885)		$ (15,546,421)	12
13																13
14	Transportation															14
15	Northwest Pipeline		$ 711,973		$ 674,762		$ 634,199		$ 614,886		$ 414,970		$ 436,893		$ 6,126,291	15
16	Paiute Pipeline		$ 542,073		$ 522,521		$ 499,118		$ 468,072		$ 368,191		$ 374,726		$ 4,945,785	16
17	Gas Transmission Northwest Corp.		$ 545,614		$ 520,814		$ 486,013		$ 471,212		$ 557,891		$ 583,149		$ 6,052,223	17
18	Tuscarora Gas Transmission		$ 1,092,184		$ 1,042,540		$ 1,005,306		$ 1,171,250		$ 657,793		$ 670,204		$ 9,825,535	18
19	Transcanada Pipeline BC (Foothills)		$ 197,476		$ 182,029		$ 177,540		$ 163,145		$ 152,205		$ 158,375		$ 1,894,892	19
20	Nova Gas Transmission		$ 455,759		$ 420,109		$ 409,747		$ 376,470		$ 350,082		$ 349,069		$ 4,361,419	20
21	Capacity Release NOVA		$ (4,714)		$ (4,500)		$ (4,339)		$ (4,071)		$ -		$ -		$ (25,339)	21
22	Capacity Release Foothills		$ (2,048)		$ (1,955)		$ (1,885)		$ (1,769)		$ -		$ -		$ (11,009)	22
23																23
24	Gas Withdrawals/ (Injections)		$ (202,228)		$ (173,198)		$ (166,353)		$ (207,062)		$ (217,325)		$ (193,840)		$ (1,876,696)	24
25																25
26	Net Gas and Transportation		$ 13,321,268		$ 11,607,130		$ 10,393,896		$ 11,883,052		$ 10,950,686		$ 13,106,540		$ 170,206,795	26
27																27
28	Other (Brokerage Fees, Cochrane Fuel Ext)		$ 5,189		$ 4,949		$ 3,609		$ 3,375		$ 2,386		$ 2,557		$ 39,919	28
29																29
30	Amortization of Prepaid Options Premiums		$ -		$ -		$ -		$ -		$ -		$ -		$ -	30
31																31
32	True-up of Prior Month Accruals		$ 763,939		$ (425,381)		$ (254,262)		$ (103,353)		$ (93,345)		$ 15,317		$ (2,184,134)	32
33																33
34	Net Other Costs		$ 769,128		$ (420,432)		$ (250,653)		$ (99,978)		$ (90,959)		$ 17,873		$ (2,144,216)	34
35																35
36	**Total Gas Costs**		**$ 14,090,395**		**$ 11,186,698**		**$ 10,143,243**		**$ 11,783,074**		**$ 10,859,727**		**$ 13,124,413**		**$ 168,062,580**	36
37																37
38	**Average Unit Cost**		**$ 3.483**		**$ 3.594**		**$ 3.392**		**$ 3.253**		**$ 3.923**		**$ 3.813**		**$ 4.672**	38
39																39

SIERRA PACIFIC POWER COMPANY
NATURAL GAS COSTS BY SUPPLIERS
FOR THE YEAR ENDED DECEMBER 31, 2023

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
Line No.	Supplier	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	Total	Line No.
1	36	$ -	$ 18,581	$ 623,230	$ 746,827	$ 520,878	$ 370,356	$ 611,553	$ 800,963	$ 570,375	$ 651,853	$ 3,910,940	$ 4,193,537	$ 13,019,091	1
2	37	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	2
3	38	$ 11,001,885	$ 3,522,050	$ 1,160,661	$ 59,138	$ -	$ -	$ 187,395	$ 125,628	$ 62,013	$ 232,932	$ 1,079,542	$ 1,663,755	$ 19,094,998	3
4	39	$ 15,185	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,185	4
5	40	$ -	$ -	$ -	$ -	$ 4,063	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,063	5
6	41	$ -	$ -	$ -	$ -	$ 3,150	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,150	6
7	50	$ 2,406,282	$ 1,478,075	$ 1,100,956	$ 778,463	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,792,073	$ 7,555,848	7
8	63	$ 26,298	$ 7,542	$ 78,331	$ 684,310	$ 621,938	$ 595,988	$ 621,938	$ 736,369	$ 750,525	$ 699,128	$ 1,675,212	$ 373,646	$ 6,871,222	8
9	64	$ 747,420	$ 61,920	$ 80,750	$ 184,144	$ 8,100	$ -	$ -	$ 40,725	$ -	$ 23,894	$ 297,448	$ 107,535	$ 1,551,936	9
10	72	$ 9,257,220	$ -	$ -	$ 886,500	$ 142,521	$ 34,775	$ 227,967	$ 146,250	$ 218,410	$ 125,535	$ 474,210	$ 292,485	$ 11,805,873	10
11	85	$ 16,725	$ -	$ -	$ -	$ 564,975	$ 537,750	$ 702,150	$ 941,625	$ 749,250	$ 620,775	$ -	$ -	$ 4,133,250	11
12	87	$ 1,298,830	$ 306,648	$ 49,026	$ 312,116	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,580	$ 1,978,200	12
13	90	$ 16,323,983	$ 3,501,745	$ 1,635,965	$ 1,087,450	$ -	$ -	$ 273,592	$ 34,250	$ -	$ 136,720	$ 61,500	$ 1,429,652	$ 24,484,858	13
14	92	$ -	$ -	$ -	$ -	$ 802,695	$ 1,055,650	$ 3,298,242	$ 2,867,985	$ 755,075	$ 1,552,563	$ 2,090,542	$ -	$ 12,422,752	14
15	95	$ -	$ -	$ 63,870	$ 38,479	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 102,349	15
16	96	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	16
17	98	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	17
18	99	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	18
19	129	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,635	$ -	$ -	$ -	$ -	$ -	$ 19,635	19
20	130	$ 38,943	$ 23,150	$ 301,344	$ 669,504	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,330	$ 1,034,272	20
21	131	$ 792,625	$ -	$ 129,680	$ -	$ 13,565	$ 7,120	$ -	$ -	$ 26,100	$ -	$ 16,725	$ 28,495	$ 1,014,310	21
22	133	$ 16,192,695	$ 3,178,560	$ 1,462,890	$ 177,750	$ 21,950	$ 52,800	$ 25,000	$ 62,250	$ 47,460	$ 219,478	$ 21,750	$ 1,457,000	$ 22,919,583	22
23	145	$ 2,630,937	$ 1,680,706	$ 1,020,006	$ 332,630	$ 151,280	$ -	$ 1,181,875	$ 1,454,516	$ 1,108,793	$ 1,017,085	$ 881,280	$ 398,178	$ 11,857,286	23
24	151	$ -	$ -	$ -	$ -	$ 38,600	$ -	$ -	$ -	$ -	$ 86,295	$ 342,897	$ -	$ 467,792	24
25	152	$ -	$ -	$ -	$ 19,133	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,133	25
26	153	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,676	$ -	$ 2,269	$ -	$ -	$ 9,944	26
27	154	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	27
28	155	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	28
29	156	$ 17,731,780	$ 3,195,554	$ 1,631,402	$ 687,186	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 275,385	$ 23,521,306	29
30	157	$ 1,537,904	$ 1,308,089	$ 199,896	$ -	$ 260,008	$ 168,409	$ 437,848	$ 356,825	$ 320,805	$ 252,010	$ 104,904	$ 34,325	$ 4,981,023	30
31	158	$ -	$ 12,040	$ -	$ 4,350	$ -	$ -	$ 22,486	$ -	$ 67,580	$ 378,060	$ 201,735	$ 775	$ 687,026	31
32	161	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,410	$ -	$ -	$ -	$ 1,410	32
33	162	$ 639,788	$ 1,156,032	$ 477,975	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 146,950	$ 2,420,744	33
34	165	$ -	$ -	$ -	$ -	$ 198,668	$ 8,200	$ 817,660	$ -	$ 478,572	$ 220,522	$ 337,361	$ -	$ 2,060,983	34
35	166	$ -	$ -	$ -	$ -	$ 35,030	$ 23,250	$ 89,875	$ -	$ -	$ -	$ -	$ -	$ 148,155	35
36	169	$ -	$ -	$ 29,757	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,975	$ 50,732	36
37	171	$ 10,294,623	$ 6,079,472	$ 3,675,124	$ 2,936,046	$ -	$ -	$ 10,469	$ 2,328	$ -	$ -	$ -	$ 2,112,086	$ 25,110,146	37
38	172	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,555,554	$ 2,025,934	$ 3,581,488	38
39	173	$ 341,000	$ 55,449	$ -	$ -	$ 2,220,182	$ 2,235,978	$ 2,768,841	$ 2,970,482	$ 2,793,852	$ 2,805,899	$ 1,324,050	$ -	$ 17,515,732	39
40	174	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	40
41	175	$ -	$ -	$ -	$ 2,430	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,345	$ 15,775	41
42	176	$ 3,200,403	$ 795,966	$ 417,722	$ 178,425	$ -	$ 3,110	$ -	$ -	$ 5,563	$ 55,920	$ 14,469	$ 760,735	$ 5,432,311	42
43	177	$ -	$ -	$ -	$ -	$ 114,158	$ 108,675	$ 141,593	$ 189,488	$ 150,975	$ 125,318	$ 670,585	$ -	$ 1,500,790	43
44	178	$ -	$ -	$ 56,500	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 56,500	44
45	179	$ 5,067,904	$ 2,649,953	$ 2,279,129	$ 1,323,592	$ -	$ -	$ 9,263	$ -	$ 6,801	$ -	$ -	$ 1,200,687	$ 12,537,328	45
46	180	$ 9,319,602	$ 4,177,568	$ 3,623,267	$ 2,516,445	$ 948,512	$ 669,025	$ 1,400,408	$ 1,705,478	$ 1,415,581	$ 1,662,487	$ 1,818,861	$ 1,990,628	$ 31,247,861	46
47	181	$ 260,005	$ 156,411	$ 106,983	$ -	$ 1,368,806	$ 1,165,203	$ 1,060,461	$ 1,249,682	$ 1,467,158	$ 1,554,660	$ 1,484,525	$ 39,000	$ 9,912,893	47
48	182	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 149,590	$ 84,481	$ -	$ -	$ 234,072	48
49	183	$ -	$ 216,195	$ -	$ -	$ 5,250	$ -	$ -	$ -	$ 7,520	$ 171,880	$ -	$ -	$ 400,845	49
50		**$ 109,142,035**	**$ 33,581,705**	**$ 20,204,462**	**$ 13,624,915**	**$ 8,044,328**	**$ 7,036,288**	**$ 13,908,248**	**$ 13,692,517**	**$ 11,153,407**	**$ 12,679,763**	**$ 18,364,090**	**$ 20,370,091**	**$ 281,801,849**	50
51															51
52	Purchased	$ 109,142,035	$ 33,581,705	$ 20,204,462	$ 13,624,915	$ 8,044,328	$ 7,036,288	$ 13,908,248	$ 13,692,517	$ 11,153,407	$ 12,679,763	$ 18,364,090	$ 20,370,091	$ 281,801,849	52
53	Sales	$ (446,143)	$ (414,512)	$ (2,650,961)	$ (6,266,701)	$ (544,309)	$ (1,395,514)	$ (2,561,454)	$ (3,663,933)	$ (2,073,714)	$ (1,060,133)	$ (2,011,485)	$ (503,490)	$ (23,592,349)	53
54	**Net**	**$ 108,695,892**	**$ 33,167,193**	**$ 17,553,501**	**$ 7,358,215**	**$ 7,500,018**	**$ 5,640,774**	**$ 11,346,794**	**$ 10,028,584**	**$ 9,079,694**	**$ 11,619,630**	**$ 16,352,605**	**$ 19,866,601**	**$ 258,209,500**	54
55															55
56	Allocation %														56
57	**LDC**	**56%**	**53%**	**54%**	**46%**	**28%**	**28%**	**12%**	**16%**	**19%**	**24%**	**47%**	**46%**		57
58	**Power Plants**	**44%**	**47%**	**46%**	**54%**	**72%**	**72%**	**88%**	**84%**	**81%**	**76%**	**53%**	**54%**		58
59															59
60	**Allocate Gas Purch / Sold**														60
61	**LDC**														61
62	Purchase	$ 61,119,540	$ 17,798,304	$ 10,910,409	$ 6,267,461	$ 2,252,412	$ 1,970,161	$ 1,668,990	$ 2,190,803	$ 2,119,147	$ 3,043,143	$ 8,631,122	$ 9,370,242	$ 127,341,733	62
63	Sale	$ (249,840)	$ (219,691)	$ (1,431,519)	$ (2,882,682)	$ (152,407)	$ (390,744)	$ (307,375)	$ (586,229)	$ (394,006)	$ (254,432)	$ (945,398)	$ (231,605)	$ (8,045,928)	63
64	**Net**	**$ 60,869,700**	**$ 17,578,612**	**$ 9,478,890**	**$ 3,384,779**	**$ 2,100,005**	**$ 1,579,417**	**$ 1,361,615**	**$ 1,604,573**	**$ 1,725,142**	**$ 2,788,711**	**$ 7,685,724**	**$ 9,138,636**	**$ 119,295,805**	64
65															65
66	**Power Plants**														66
67	Purchase	$ 48,022,496	$ 15,783,401	$ 9,294,052	$ 7,357,454	$ 5,791,916	$ 5,066,128	$ 12,239,258	$ 11,501,714	$ 9,034,260	$ 9,636,620	$ 9,732,968	$ 10,999,849	$ 154,460,116	67
68	Sale	$ (196,303)	$ (194,821)	$ (1,219,442)	$ (3,384,018)	$ (391,903)	$ (1,004,770)	$ (2,254,080)	$ (3,077,704)	$ (1,679,708)	$ (805,701)	$ (1,066,087)	$ (271,885)	$ (15,546,421)	68
69	**Net**	**$ 47,826,193**	**$ 15,588,581**	**$ 8,074,610**	**$ 3,973,436**	**$ 5,400,013**	**$ 4,061,357**	**$ 9,985,178**	**$ 8,424,010**	**$ 7,354,552**	**$ 8,830,919**	**$ 8,666,881**	**$ 10,727,964**	**$ 138,913,695**	69
70															70
71															71
72	**Total Net Gas Purchased**	**$ 108,695,892**	**$ 33,167,193**	**$ 17,553,501**	**$ 7,358,215**	**$ 7,500,018**	**$ 5,640,774**	**$ 11,346,794**	**$ 10,028,584**	**$ 9,079,694**	**$ 11,619,630**	**$ 16,352,605**	**$ 19,866,601**	**$ 258,209,500**	72

SIERRA PACIFIC POWER COMPANY
NATURAL GAS VOLUMES BY SUPPLIERS (MMBTU)
FOR THE YEAR ENDED DECEMBER 31, 2023

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
Line No.	**Supplier**	**2023 January**	**2023 February**	**2023 March**	**2023 April**	**2023 May**	**2023 June**	**2023 July**	**2023 August**	**2023 September**	**2023 October**	**2023 November**	**2023 December**	**Total**	**Line No.**
1	36	-	8,578	271,407	218,695	201,500	198,033	201,500	201,500	195,000	201,500	1,680,000	1,689,500	5,067,214	1
2	37	-	-	-	-	-	-	-	-	-	-	-	-	-	2
3	38	279,500	308,000	209,500	15,000	-	-	62,000	31,000	25,000	70,463	173,597	267,896	1,441,956	3
4	39	1,000	-	-	-	-	-	-	-	-	-	-	-	1,000	4
5	40	-	-	-	-	2,500	-	-	-	-	-	-	-	2,500	5
6	41	-	-	-	-	1,500	-	-	-	-	-	-	-	1,500	6
7	50	527,000	476,000	527,000	375,000	-	-	-	-	-	-	-	868,000	2,773,000	7
8	63	9,094	3,638	34,121	376,094	387,500	375,000	387,500	389,000	375,000	387,500	840,000	175,500	3,739,947	8
9	64	43,300	11,900	15,000	94,200	5,000	-	-	15,000	-	9,621	103,000	31,300	328,321	9
10	72	186,000	-	-	225,000	81,000	20,000	67,317	42,500	90,379	50,100	88,000	46,500	896,796	10
11	85	1,000	-	-	-	232,500	225,000	232,500	232,500	225,000	232,500	-	-	1,381,000	11
12	87	71,000	41,800	13,600	141,300	-	-	-	-	-	-	-	3,000	270,700	12
13	90	524,829	302,200	312,400	294,000	-	-	72,696	10,000	-	53,000	15,000	248,016	1,832,141	13
14	92	-	-	-	-	338,899	448,820	995,600	682,500	235,000	472,153	399,708	-	3,572,680	14
15	95	-	-	15,500	5,458	-	-	-	-	-	-	-	-	20,958	15
16	96	-	-	-	-	-	-	-	-	-	-	-	-	-	16
17	98	-	-	-	-	-	-	-	-	-	-	-	-	-	17
18	99	-	-	-	-	-	-	-	-	-	-	-	-	-	18
19	129	-	-	-	-	-	-	5,100	-	-	-	-	-	5,100	19
20	130	12,732	10,913	131,276	342,304	-	-	-	-	-	-	-	948	498,174	20
21	131	50,000	-	12,100	-	8,151	3,200	-	-	13,743	-	8,151	6,000	101,346	21
22	133	325,500	252,000	279,000	45,000	12,500	30,000	5,000	22,500	19,500	57,649	4,000	232,500	1,285,149	22
23	145	183,708	246,824	175,168	55,100	62,000	-	387,500	356,499	329,998	376,813	162,000	172,734	2,508,344	23
24	151	-	-	-	-	19,500	-	-	-	-	32,200	114,186	-	165,886	24
25	152	-	-	-	10,426	-	-	-	-	-	-	-	-	10,426	25
26	153	-	-	-	-	-	-	-	3,223	-	1,043	-	-	4,265	26
27	154	-	-	-	-	-	-	-	-	-	-	-	-	-	27
28	155	-	-	-	-	-	-	-	-	-	-	-	-	-	28
29	156	418,919	324,719	347,019	262,953	-	-	-	-	-	-	-	69,439	1,423,049	29
30	157	224,400	333,074	53,300	-	121,310	91,820	128,774	108,475	147,573	139,343	56,111	10,000	1,414,180	30
31	158	-	2,800	-	1,500	-	-	5,796	-	28,700	120,217	34,500	200	193,713	31
32	161	-	-	-	-	-	-	-	-	600	-	-	-	600	32
33	162	47,500	135,900	57,500	-	-	-	-	-	-	-	-	40,000	280,900	33
34	165	-	-	-	-	101,800	4,000	221,000	-	184,600	64,583	63,736	-	639,719	34
35	166	-	-	-	-	15,500	15,000	20,000	-	-	-	-	-	50,500	35
36	169	-	-	4,200	-	-	-	-	-	-	-	-	5,000	9,200	36
37	171	2,192,500	1,960,000	1,730,500	1,400,000	-	-	1,900	700	-	-	-	1,023,000	8,308,600	37
38	172	-	-	-	-	-	-	-	-	-	-	780,000	309,989	1,089,989	38
39	173	20,000	4,300	-	-	1,384,500	1,410,000	1,715,000	1,581,000	1,395,000	1,553,500	210,000	-	9,273,300	39
40	174	-	-	-	-	-	-	-	-	-	-	-	-	-	40
41	175	-	-	-	900	-	-	-	-	-	-	-	3,400	4,300	41
42	176	69,000	67,407	85,600	45,000	-	1,800	-	-	2,500	8,000	2,500	129,000	410,807	42
43	177	-	-	-	-	46,500	45,000	46,500	46,500	45,000	46,500	127,600	-	403,600	43
44	178	-	-	5,000	-	-	-	-	-	-	-	-	-	5,000	44
45	179	243,185	429,164	571,260	351,271	-	-	2,351	-	2,900	-	-	290,467	1,890,597	45
46	180	1,636,893	1,243,171	1,449,386	1,247,923	426,576	355,000	460,500	429,500	505,279	560,224	391,029	911,831	9,617,312	46
47	181	15,824	21,960	11,440	-	835,776	702,298	496,347	624,472	721,912	754,645	655,674	12,000	4,852,349	47
48	182	-	-	-	-	-	-	-	-	49,215	34,775	-	-	83,990	48
49	183	-	22,900	-	-	2,500	-	-	-	3,200	39,313	-	-	67,913	49
50		**7,082,884**	**6,207,247**	**6,311,279**	**5,507,124**	**4,287,012**	**3,924,971**	**5,514,881**	**4,776,869**	**4,595,099**	**5,265,642**	**5,908,792**	**6,546,220**	**65,928,019**	50
51															51
52	Purchased	7,082,884	6,207,247	6,311,279	5,507,124	4,287,012	3,924,971	5,514,881	4,776,869	4,595,099	5,265,642	5,908,792	6,546,220	65,928,019	52
53	Sales	(20,948)	(76,208)	(529,929)	(1,570,378)	(274,700)	(678,797)	(916,944)	(1,035,682)	(906,439)	(498,946)	(697,045)	(172,925)	(7,378,940)	53
54	**Net**	**7,061,936**	**6,131,039**	**5,781,350**	**3,936,746**	**4,012,312**	**3,246,174**	**4,597,936**	**3,741,187**	**3,688,660**	**4,766,696**	**5,211,747**	**6,373,294**	**58,549,079**	54
55															55
56	Allocation %														56
57	**LDC**	**56%**	**53%**	**54%**	**46%**	**28%**	**28%**	**12%**	**16%**	**19%**	**24%**	**47%**	**46%**		57
58	**Power Plants**	**44%**	**47%**	**46%**	**54%**	**72%**	**72%**	**88%**	**84%**	**81%**	**76%**	**53%**	**54%**		58
59															59
60	**Allocate Gas Purch / Sold**														60
61	**LDC**														61
62	Purchase	3,966,415	3,289,841	3,408,090	2,533,277	1,200,363	1,098,992	661,786	764,299	873,069	1,263,754	2,777,132	3,011,261	24,848,280	62
63	Sale	(11,731)	(40,390)	(286,161)	(722,374)	(76,916)	(190,063)	(110,033)	(165,709)	(172,223)	(119,747)	(327,611)	(79,546)	(2,302,505)	63
64	**Net**	**3,954,684**	**3,249,451**	**3,121,929**	**1,810,903**	**1,123,447**	**908,929**	**551,752**	**598,590**	**700,845**	**1,144,007**	**2,449,521**	**2,931,715**	**22,545,775**	64
65															65
66	**Power Plants**														66
67	Purchase	3,116,469	2,917,406	2,903,188	2,973,847	3,086,649	2,825,979	4,853,095	4,012,570	3,722,030	4,001,888	3,131,660	3,534,959	41,079,740	67
68	Sale	(9,217)	(35,818)	(243,767)	(848,004)	(197,784)	(488,734)	(806,911)	(869,973)	(734,215)	(379,199)	(369,434)	(93,380)	(5,076,435)	68
69	**Net**	**3,107,252**	**2,881,588**	**2,659,421**	**2,125,843**	**2,888,865**	**2,337,245**	**4,046,184**	**3,142,597**	**2,987,815**	**3,622,689**	**2,762,226**	**3,441,579**	**36,003,304**	69
70															70
71															71
72	**Total Net Gas Purchased**	**7,061,936**	**6,131,039**	**5,781,350**	**3,936,746**	**4,012,312**	**3,246,174**	**4,597,936**	**3,741,187**	**3,688,660**	**4,766,696**	**5,211,747**	**6,373,294**	**58,549,079**	72

SIERRA PACIFIC POWER COMPANY
NATURAL GAS COSTS PER MMBTU BY SUPPLIERS
FOR THE YEAR ENDED DECEMBER 31, 2023

Exhibit E-1.5
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
Line No.	Supplier	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	Total	Line No.
1	36	$ -	$ 2.166	$ 2.296	$ 3.415	$ 2.585	$ 1.870	$ 3.035	$ 3.975	$ 2.925	$ 3.235	$ 2.328	$ 2.482	$ 2.569	1
2	37	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	2
3	38	$ 39.363	$ 11.435	$ 5.540	$ 3.943	$ -	$ -	$ 3.023	$ 4.053	$ 2.481	$ 3.306	$ 6.219	$ 6.211	$ 13.242	3
4	39	$ 15.185	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15.185	4
5	40	$ -	$ -	$ -	$ -	$ 1.625	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.625	5
6	41	$ -	$ -	$ -	$ -	$ 2.100	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.100	6
7	50	$ 4.566	$ 3.105	$ 2.089	$ 2.076	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.065	$ 2.725	7
8	63	$ 2.892	$ 2.073	$ 2.296	$ 1.820	$ 1.605	$ 1.589	$ 1.605	$ 1.893	$ 2.001	$ 1.804	$ 1.994	$ 2.129	$ 1.837	8
9	64	$ 17.261	$ 5.203	$ 5.383	$ 1.955	$ 1.620	$ -	$ -	$ 2.715	$ -	$ 2.484	$ 2.888	$ 3.436	$ 4.727	9
10	72	$ 49.770	$ -	$ -	$ 3.940	$ 1.760	$ 1.739	$ 3.387	$ 3.441	$ 2.417	$ 2.506	$ 5.389	$ 6.290	$ 13.165	10
11	85	$ 16.725	$ -	$ -	$ -	$ 2.430	$ 2.390	$ 3.020	$ 4.050	$ 3.330	$ 2.670	$ -	$ -	$ 2.993	11
12	87	$ 18.293	$ 7.336	$ 3.605	$ 2.209	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.860	$ 7.308	12
13	90	$ 31.103	$ 11.588	$ 5.237	$ 3.699	$ -	$ -	$ 3.764	$ 3.425	$ -	$ 2.580	$ 4.100	$ 5.764	$ 13.364	13
14	92	$ -	$ -	$ -	$ -	$ 2.369	$ 2.352	$ 3.313	$ 4.202	$ 3.213	$ 3.288	$ 5.230	$ -	$ 3.477	14
15	95	$ -	$ -	$ 4.121	$ 7.050	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.884	15
16	96	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	16
17	98	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	17
18	99	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	18
19	129	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.850	$ -	$ -	$ -	$ -	$ -	$ 3.850	19
20	130	$ 3.059	$ 2.121	$ 2.296	$ 1.956	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.403	$ 2.076	20
21	131	$ 15.853	$ -	$ 10.717	$ -	$ 1.664	$ 2.225	$ -	$ -	$ 1.899	$ -	$ 2.052	$ 4.749	$ 10.008	21
22	133	$ 49.747	$ 12.613	$ 5.243	$ 3.950	$ 1.756	$ 1.760	$ 5.000	$ 2.767	$ 2.434	$ 3.807	$ 5.438	$ 6.267	$ 17.834	22
23	145	$ 14.321	$ 6.809	$ 5.823	$ 6.037	$ 2.440	$ -	$ 3.050	$ 4.080	$ 3.360	$ 2.699	$ 5.440	$ 2.305	$ 4.727	23
24	151	$ -	$ -	$ -	$ -	$ 1.980	$ -	$ -	$ -	$ -	$ 2.680	$ 3.003	$ -	$ 2.820	24
25	152	$ -	$ -	$ -	$ 1.835	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.835	25
26	153	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.382	$ -	$ 2.176	$ -	$ -	$ 2.332	26
27	154	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	27
28	155	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	28
29	156	$ 42.328	$ 9.841	$ 4.701	$ 2.613	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.966	$ 16.529	29
30	157	$ 6.853	$ 3.927	$ 3.750	$ -	$ 2.143	$ 1.834	$ 3.400	$ 3.290	$ 2.174	$ 1.809	$ 1.870	$ 3.433	$ 3.522	30
31	158	$ -	$ 4.300	$ -	$ 2.900	$ -	$ -	$ 3.880	$ -	$ 2.355	$ 3.145	$ 5.847	$ 3.875	$ 3.547	31
32	161	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.350	$ -	$ -	$ -	$ 2.350	32
33	162	$ 13.469	$ 8.507	$ 8.313	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.674	$ 8.618	33
34	165	$ -	$ -	$ -	$ -	$ 1.952	$ 2.050	$ 3.700	$ -	$ 2.593	$ 3.415	$ 5.293	$ -	$ 3.222	34
35	166	$ -	$ -	$ -	$ -	$ 2.260	$ 1.550	$ 4.494	$ -	$ -	$ -	$ -	$ -	$ 2.934	35
36	169	$ -	$ -	$ 7.085	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.195	$ 5.514	36
37	171	$ 4.695	$ 3.102	$ 2.124	$ 2.097	$ -	$ -	$ 5.510	$ 3.325	$ -	$ -	$ -	$ 2.065	$ 3.022	37
38	173	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.994	$ 6.536	$ 3.286	38
39	174	$ 17.050	$ 12.895	$ -	$ -	$ 1.604	$ 1.586	$ 1.615	$ 1.879	$ 2.003	$ 1.806	$ 6.305	$ -	$ 1.889	39
40	175	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	40
41	176	$ -	$ -	$ -	$ 2.700	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.925	$ 3.669	41
42	177	$ 46.383	$ 11.808	$ 4.880	$ 3.965	$ -	$ 1.728	$ -	$ -	$ 2.225	$ 6.990	$ 5.788	$ 5.897	$ 13.224	42
43	178	$ -	$ -	$ -	$ -	$ 2.455	$ 2.415	$ 3.045	$ 4.075	$ 3.355	$ 2.695	$ 5.255	$ -	$ 3.719	43
44	179	$ -	$ -	$ 11.300	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11.300	44
45	180	$ 20.840	$ 6.175	$ 3.990	$ 3.768	$ -	$ -	$ 3.940	$ -	$ 2.345	$ -	$ -	$ 4.134	$ 6.631	45
46	181	$ 5.694	$ 3.360	$ 2.500	$ 2.017	$ 2.224	$ 1.885	$ 3.041	$ 3.971	$ 2.802	$ 2.968	$ 4.652	$ 2.183	$ 3.249	46
47	182	$ 16.431	$ 7.123	$ 9.352	$ -	$ 1.638	$ 1.659	$ 2.137	$ 2.001	$ 2.032	$ 2.060	$ 2.264	$ 3.250	$ 2.043	47
48	183	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.040	$ 2.429	$ -	$ -	$ 2.787	48
49		$ -	$ 9.441	$ -	$ -	$ 2.100	$ -	$ -	$ -	$ 2.350	$ 4.372	$ -	$ -	$ 5.902	49
50		**$ 15.409**	**$ 5.410**	**$ 3.201**	**$ 2.474**	**$ 1.876**	**$ 1.793**	**$ 2.522**	**$ 2.866**	**$ 2.427**	**$ 2.408**	**$ 3.108**	**$ 3.112**	**$ 4.274**	50

EXHIBIT E-2

SIERRA PACIFIC POWER COMPANY
SUMMARY OF PURCHASED POWER
FOR THE 12 MONTHS ENDED DECEMBER 31, 2023

Line No.	Distribution Of Purchased Power	December 2023 MWh	December 2023 Dollars	Total MWh	Total Dollars	Line No.
1	**AMOR IX LLC**					1
2	(4) Energy Imbalances Sales and Losses	(159)	(9,095)	(1,737)	(125,733)	2
3	Total AMOR IX LLC	(159)	(9,095)	(1,737)	(125,733)	3
4						4
5	**AMPRENEW OFFTAKE 1 LLC**					5
6	(4) Energy Imbalances Sales and Losses	(13)	(737)	(125)	(8,441)	6
7	Total AMPRENEW OFFTAKE 1 LLC	(13)	(737)	(125)	(8,441)	7
8						8
9	**AVANGRID RENEWABLES, LLC**					9
10	(B) Short-Term Firm Energy	0	0	0	0	10
11	(B) Short-Term Firm Energy - NRSG Purchases (Prior Month Adjustment)	0	0	0	0	11
12	(4) Energy Imbalances Sales and Losses	99	6,755	(662)	(41,755)	12
13	(7) Option Premium Revenue	0	0	0	0	13
14	Total AVANGRID RENEWABLES, LLC	99	6,755	(662)	(41,755)	14
15						15
16	**AVISTA ENERGY INC.**					16
17	(B) Short-Term Firm Energy	0	0	0	0	17
18	(B) Short-Term Firm Energy - NRSG (Prior Month Adjustment)	0	0	0	0	18
19	(4) Energy Imbalances Sales and Losses	0	0	0	0	19
20	(2) Firm Energy	0	0	0	0	20
21	Total AVISTA ENERGY INC.	0	0	0	0	21
22						22
23	**BARRICK GOLDSTRIKE MINES LLC**					23
24	(B) Short-Term Firm Energy	0	0	0	0	24
25	(B) Short-Term Firm Energy (prior month adjustment)	0	0	0	0	25
26	Total BARRICK GOLDSTRIKE MINES LLC	0	0	0	0	26
27						27
28	**BONNEVILLE POWER ADMINISTRATION**					28
29	(B) Short-Term Firm Energy	0	0	0	0	29
30	(B) Short-Term Firm Energy - NRSG (Prior Month Adjustment)	0	0	0	0	30
31	(2) Firm Energy	0	0	0	0	31
32	(4) Energy Imbalances Sales and Losses	(2)	(78)	(2)	(78)	32
33	Total BONNEVILLE POWER ADMINISTRATION	(2)	(78)	(2)	(78)	33
34						34
35	**BLACK HILLS POWER**					35
36	(4) Energy Imbalances Sales and Losses	0	0	0	0	36
37	Total BLACK HILLS POWER	0	0	0	0	37
38						38
39	**BROOKFIELD ENERGY MARKETING**					39
40	(7) Option Premium Revenue	0	0	0	0	40
41	(4) Energy Imbalances Sales and Losses	0	0	(0)	(1)	41
42	Total BROOKFIELD ENERGY MARKETING	0	0	(0)	(1)	42
43						43
44	**CALPECO**					44
45	(B) Short-Term Firm Energy	0	74,973	0	899,676	45
46	(B) Short-Term Firm Energy (Prior Month Adjustment)	0	0	0	0	46
47	Total CALPECO	0	74,973	0	899,676	47
48						48
49	**CALPINE ENERGY SERVICES, L.P.**					49
50	(4) Energy Imbalances Sales and Losses	(81)	(4,855)	(86)	(4,866)	50
51	Total CALPINE ENERGY SERVICES, L.P.	(81)	(4,855)	(86)	(4,866)	51
52						52
53	**CHELAN COUNTY PUD**					53
54	(B) Short-Term Firm Energy - NRSG	0	0	0	0	54
55	(B) Short-Term Firm Energy - NRSG (Prior Month Adjustment)	0	0	0	0	55
56	(2) Firm Energy	0	0	0	0	56
57	Total CHELAN COUNTY PUD	0	0	0	0	57
58						58

SIERRA PACIFIC POWER COMPANY
SUMMARY OF PURCHASED POWER
FOR THE 12 MONTHS ENDED DECEMBER 31, 2023

Line No.	Distribution Of Purchased Power	December 2023 MWh	December 2023 Dollars	Total MWh	Total Dollars	Line No.
59	**CITIGROUP ENERGY, INC**					59
60	(7) Option Premium Revenue	0	0	0	0	60
61	Total CITIGROUP ENERGY, INC	0	0	0	0	61
62						62
63	**CONOCOPHILLIPS COMPANY**					63
64	(4) Energy Imbalances Sales and Losses	4	143	(5)	(168)	64
65	Total CONOCOPHILLIPS COMPANY	4	143	(5)	(168)	65
66						66
67	**CORAL POWER, L.L.C. - SHELL ENERGY**					67
68	(D) Call Option	0	0	0	0	68
69	(2) Firm Energy	0	0	0	0	69
70	(4) Energy Imbalances Sales and Losses	121	6,043	(811)	(101,130)	70
71	Total CORAL POWER, L.L.C. - SHELL ENERGY	121	6,043	(811)	(101,130)	71
72						72
73	**DTE**					73
74	(7) Option Premium Revenue	0	0	0	0	74
75	Total DTE	0	0	0	0	75
76						76
77	**DYNASTY POWER**					77
78	(4) Energy Imbalances Sales and Losses	(130)	(5,552)	(809)	(31,582)	78
79	(7) Option Premium Revenue	0	0	0	0	79
80	Total DYNASTY POWER	(130)	(5,552)	(809)	(31,582)	80
81						81
82	**EAGLE ENERGY PARTNERS**					82
83	(4) Energy Imbalances Sales and Losses	0	0	0	0	83
84	Total EAGLE ENERGY PARTNERS	0	0	0	0	84
85						85
86	**ENERGY KEEPERS, INC**					86
87	(4) Energy Imbalances Sales and Losses	0	0	(16)	(917)	87
88	Total ENERGY KEEPERS, INC	0	0	(16)	(917)	88
89						89
90	**GRANT COUNTY PUD**					90
91	(B) Short-Term Firm Energy - NRSG	0	0	0	0	91
92	(B) Short-Term Firm Energy - NRSG Prior Month	0	0	0	0	92
93	(2) Firm Energy	0	0	0	0	93
94	Total GRANT COUNTY PUD	0	0	0	0	94
95						95
96	**GRIDFORCE ENERGY**					96
97	(B) Short-Term Firm Energy	0	0	0	0	97
98	(B) Short-Term Firm Energy - NRSG (Prior Month Adjustment)	0	0	0	0	98
99	(4) Energy Imbalances Sales and Losses	0	0	0	0	99
100	Total GRIDFORCE ENERGY	0	0	0	0	100
101						101
102	**GUZMAN ENERGY LLC**					102
103	(4) Energy Imbalances Sales and Losses	138	5,476	(243)	(14,132)	103
104	Total GUZMAN ENERGY LLC	138	5,476	(243)	(14,132)	104
105						105
106	**IDAHO POWER COMPANY**					106
107	(B) Short-Term Firm Energy (Joint Dispatch)	0	0	0	0	107
108	(B) Short-Term Firm Energy (Joint Dispatch) (Prior Month Adjustment)	0	0	(1)	(7)	108
109	(B) Short-Term Firm Energy - NRSG Purchases (Prior Month Adjustment)	0	0	23	2,271	109
110	(4) Energy Imbalances Sales and Losses	(6)	(1,037)	(20)	(1,466)	110
111	(2) Firm Energy NRSG	0	0	0	0	111
112	(2) Firm Energy NRSG (Prior Month Adjustment)	(37)	(1,746)	(130)	(6,415)	112
113	Total IDAHO POWER COMPANY	(43)	(2,783)	(128)	(5,616)	113
114						114

SIERRA PACIFIC POWER COMPANY
SUMMARY OF PURCHASED POWER
FOR THE 12 MONTHS ENDED DECEMBER 31, 2023

Line No.	Distribution Of Purchased Power	December 2023 MWh	December 2023 Dollars	Total MWh	Total Dollars	Line No.
115	**MORGAN STANLEY CAPITAL GROUP, INC.**					115
116	(B) Short-Term Firm Energy	0	0	0	0	116
117	(D) Call Option	0	0	0	0	117
118	(2) Firm Energy	0	0	0	0	118
119	(4) Energy Imbalances Sales and Losses	(160)	(2,717)	(2,442)	(42,912)	119
120	(7) Option Premium Revenue	0	0	0	0	120
121	Total MORGAN STANLEY CAPITAL GROUP, INC.	(160)	(2,717)	(2,442)	(42,912)	121
122						122
123	**MACQUARIE POWER**					123
124	(4) Energy Imbalances Sales and Losses	(33)	(2,436)	(328)	(22,794)	124
125	(7) Option Premium Revenue	0	0	0	0	125
126	Total MACQUARIE POWER	(33)	(2,436)	(328)	(22,794)	126
127						127
128	**MAG ENERGY SOLUTIONS**					128
129	(4) Energy Imbalances Sales and Losses	(2)	(99)	(27)	(1,259)	129
130	Total MAG ENERGY SOLUTIONS	(2)	(99)	(27)	(1,259)	130
131						131
132	**MERCURIA ENERGY AMERICA, LLC**					132
133	(4) Energy Imbalances Sales and Losses	(1)	(81)	(2)	(167)	133
134	Total MERCURIA ENERGY AMERICA, LLC	(1)	(81)	(2)	(167)	134
135						135
136	**NEVADA GOLD ENERGY**					136
137	(B) Short-Term Firm Energy	0	0	6,480	453,600	137
138	(B) Short-Term Firm Energy (Prior Month Adjustment)	0	0	(560)	(39,200)	138
139	Total NEVADA GOLD ENERGY	0	0	5,920	414,400	139
140						140
141	**NEVADA POWER - CAISO (EIM)**					141
142	Nevada Power (CAISO) - Entity	0	336,014	0	4,641,655	142
143	Nevada Power (CAISO) - Entity (prior month adjustment)	0	(185,011)	0	795,309	143
144	Nevada Power (CAISO) - Entity (prior year adjustment)	0	(113,589)	0	932,190	144
145	Nevada Power (CAISO) - Entity CAISO Refunds	0	0	0	0	145
146	Nevada Power (CAISO) - Resource Purchases	59,435	2,512,384	700,822	38,614,320	146
147	Nevada Power (CAISO) - Resource Sales	(76,554)	(3,431,664)	(1,213,319)	(59,219,587)	147
148	Nevada Power (CAISO) - Resource Purchases (prior month adjustment)	(10,279)	73,569	(11,599)	(3,837,128)	148
149	Nevada Power (CAISO) - Resource Sales (prior month adjustment)	9,986	30,622	(3,287)	4,351,731	149
150	Nevada Power (CAISO) - Resource Purchases(prior year adjustment)	1,384	58,088	58,469	3,567,304	150
151	Nevada Power (CAISO) - Resource Sales (prior year adjustment)	(335)	58,359	(23,021)	(3,597,295)	151
152	Total NEVADA POWER - CAISO (EIM)	(16,362)	(661,228)	(491,934)	(13,751,500)	152
153						153
154	**NEVADA POWER - JOINT DISPATCH**					154
155	(B) Short-Term Firm Energy - Allegro Purchases NPC on Behalf of SPPC	14,580	914,226	1,102,898	165,804,444	155
156	(B) Short-Term Firm Energy (Prior Month Adjustment) - NPC for SPPC	0	1	4,480	2,703,304	156
157	(B) Short-Term Firm Energy (Prior Year Adjustment) - NPC for SPPC	0	0	0	(23,781)	157
158	(B) Short-Term Firm Energy - Allegro Purchases SPPC on Behalf of NPC	0	0	0	0	158
159	(B) Short-Term Firm Energy (Prior Month Adjustment) - SPPC for NPC	0	0	0	0	159
160	(B) Short-Term Firm Energy (Prior Year Adjustment) - SPPC for NPC	0	0	0	0	160
161	(B) Short-Term Firm Energy - Joint Dispatch Stranded Energy	0	0	0	0	161
162	(B) Short-Term Firm Energy - Transfer Payment SPPC to NPC	92,946	7,545,157	790,668	32,941,547	162
163	(B) Short-Term Firm Energy - Transfer Payment Prior Month Adjustment	0	846,176	55,622	763,586	163
164	(B) Short-Term Firm Energy - Transfer Payment Prior Year Adjustment	0	0	0	0	164
165	(2) Firm Energy - Allegro Sales SPPC for NPC	0	0	0	0	165
166	(2) Firm Energy - Allegro Sales NPC on behalf of SPPC	(2,377)	(76,673)	(94,035)	(3,747,022)	166
167	(2) Firm Energy (Prior Month Adjustment) - Allegro Sales NPC for SPPC	0	548	654	(261,608)	167
168	(2) Firm Energy (Prior Year Adjustment) - Allegro Sales NPC for SPPC	0	0	0	0	168
169	(2) Short-Term Firm Energy - Transfer Payment NPC to SPPC	0	0	(59,819)	(9,216,700)	169
170	(2) Short-Term Firm Energy - Transfer Payment NPC to SPPC (Prior Month Ad	0	0	55,732	2,042,479	170
171	(2) Firm Energy - Joint Dispatch Stranded Energy	0	0	0	0	171
172	Total NEVADA POWER - JOINT DISPATCH	105,149	9,229,434	1,856,200	191,006,250	172
173						173

SIERRA PACIFIC POWER COMPANY
SUMMARY OF PURCHASED POWER
FOR THE 12 MONTHS ENDED DECEMBER 31, 2023

		December 2023		Total		
Line No.	Distribution Of Purchased Power	MWh	Dollars	MWh	Dollars	Line No.
174	**NORTHWEST ENERGY**					174
175	(B) Short-Term Firm Energy - NRSG Purchases (Prior Month Adjustment)	0	0	0	0	175
176	Total NORTHWEST ENERGY	0	0	0	0	176
177						177
178	**OPEN MOUNTAIN ENERGY**					178
179	(4) Energy Imbalances Sales and Losses	(12)	(646)	(72)	(5,087)	179
180	Total OPEN MOUNTAIN ENERGY	(12)	(646)	(72)	(5,087)	180
181						181
182	**ORMAT - Orni 47 Wild Rose**			0	0	182
183	(4) Energy Imbalances Sales and Losses	(815)	(45,942)	(6,760)	(546,590)	183
184	Total ORMAT - Orni 47 Wild Rose	(815)	(45,942)	(6,760)	(546,590)	184
185						185
186	**PACIFICORP**					186
187	(A) Economy Energy	0	0	0	0	187
188	(B) Short-Term Firm Energy	0	0	0	0	188
189	(B) Short-Term Firm Energy - NRSG Purchases (Prior Month Adjustment)	0	0	61	5,870	189
190	(2) Firm Energy	0	0	0	0	190
191	(2) Firm Energy - NRSG - Prior Month Adjustment	0	0	(260)	(22,097)	191
192	(4) Energy Imbalances Sales and Losses	(18)	(1,349)	(150)	(10,920)	192
193	Total PACIFICORP	(18)	(1,349)	(348.75)	(27,147)	193
194						194
195	**PACIFIC Gas & Electric Company**					195
196	(4) Energy Imbalances Sales and Losses	36	1,570	(91)	(3,829)	196
197	Total PACIFIC Gas & Electric Company	36	1,570	(91)	(3,829)	197
198						198
199	**PATUA POWER**					199
200	(B) Short-Term Firm Energy	0	0	0	0	200
201	(4) Energy Imbalances Sales and Losses	(222)	(12,219)	(2,062)	(136,524)	201
202	Total PATUA POWER	(222)	(12,219)	(2,061.95)	(136,524)	202
203						203
204	**PHILLIPS 66 ENERGY TRADING LLC**					204
205	(4) Energy Imbalances Sales and Losses	33	1,618	(33)	(1,618)	205
206	Total PHILLIPS 66 ENERGY TRADING LLC	33	1,618	(33)	(1,618)	206
207						207
208	**PLUMAS SIERRA RURAL ELECTRIC**					208
209	(4) Energy Imbalances Sales and Losses	(95)	(4,911)	(178)	(17,748)	209
210	Total PLUMAS SIERRA RURAL ELECTRIC	(95)	(4,911)	(178)	(17,748)	210
211						211
212	**PORTLAND GENERAL ELECTRIC**					212
213	(4) Energy Imbalances Sales and Losses	51	1,529	(199)	(9,679)	213
214	Total PORTLAND GENERAL ELECTRIC	51	1,529	(199)	(9,679)	214
215						215
216	**POWEREX**					216
217	(B) Short-Term Firm Energy	0	0	0	0	217
218	(4) Energy Imbalances Sales and Losses	(299)	(11,465)	(3,586)	(125,346)	218
219	Total POWEREX	(299)	(11,465)	(3,586)	(125,346)	219
220						220
221	**PUBLIC SERVICE COMPANY OF COLORADO**					221
222	(B) Short-Term Firm Energy - NRSG Purchases (Prior Month Adjustment)	0	0	43	4,058	222
223	(2) Firm Energy - NRSG - Prior Month Adjustment	0	0	(117)	(9,484)	223
224	(7) Option Premium Revenue	0	0	0	0	224
225	Total PUBLIC SERVICE COMPANY OF COLORADO	0	0	(74)	(5,427)	225
226						226
227	**RAINBOW ENERGY MARKETING CORPORATION**					227
228	(4) Energy Imbalances Sales and Losses	(671)	(46,573)	(2,834)	(175,192)	228
229	Total RAINBOW ENERGY MARKETING CORPORATION	(671)	(46,573)	(2,834)	(175,192)	229
230						230

SIERRA PACIFIC POWER COMPANY
SUMMARY OF PURCHASED POWER
FOR THE 12 MONTHS ENDED DECEMBER 31, 2023

Line No.	Distribution Of Purchased Power	December 2023 MWh	December 2023 Dollars	Total MWh	Total Dollars	Line No.
231	**SOUTHERN CALIFORNIA EDISON**					231
232	(4) Energy Imbalances Sales and Losses	0	0	2	73	232
233	Total SOUTHERN CALIFORNIA EDISON	0	0	2	73	233
234						234
235	**STAR PEAK GEOTHERMAL**					235
236	(4) Energy Imbalances Sales and Losses	(26)	(1,493)	(312)	(21,558)	236
237	Total STAR PEAK GEOTHERMAL	(26)	(1,493)	(312)	(21,558)	237
238						238
239	**TEC ENERGY**					239
240	(4) Energy Imbalances Sales and Losses	(2)	(121)	(2)	(121)	240
241	Total TEC ENERGY	(2)	(121)	(2)	(121)	241
242						242
243	**TENASKA POWER SERVICES**					243
244	(4) Energy Imbalances Sales and Losses	0	0	(3)	(279)	244
245	(7) Option Premium Revenue	0	0	0	0	245
246	Total TENASKA POWER SERVICES	0	0	(3)	(279)	246
247						247
248	**THE ENERGY AUTHORITY**					248
249	(2) Firm Energy			0	0	249
250	(4) Energy Imbalances Sales and Losses	(336)	(19,566)	(1,676)	(128,778)	250
251	Total THE ENERGY AUTHORITY	(336)	(19,566)	(1,676)	(128,778)	251
252						252
253	**UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS**					253
254	(4) Energy Imbalances Sales and Losses	0	0	0	0	254
255	Total UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS	0	0	0	0	255
256						256
257	**TRANSALTA ENERGY MARKETING (US), INC.**					257
258	(B) Short-Term Firm Energy	0	0	0	0	258
259	(D) Call Option	0	0	0	0	259
260	(4) Energy Imbalances Sales and Losses	(37)	(2)	(619)	(32,135)	260
261	(7) Option Premium Revenue	0	0	0	0	261
262	(2) Firm Energy	0	0	0	0	262
263	Total TRANSALTA ENERGY MARKETING (US), INC.	(37)	(2)	(619)	(32,135)	263
264						264
265	**VITOL, INC.**					265
266	(4) Energy Imbalances Sales and Losses	0	0	(705)	(34,504)	266
267	Total VITOL, INC.	0	0	(705)	(34,504)	267
268						268
269	**WESTERN AREA POWER ADMINISTRATION - COLORADO-MISSOURI**					269
270	(B) Short-Term Firm Energy - NRSG Purchases (Prior Month Adjustment)	0	0	32	3,078	270
271	(2) Firm Energy - NRSG - Prior Month Adjustment	0	0	(565)	(48,384)	271
272	Total WESTERN AREA POWER ADMINISTRATION - COLORADO-MISSOUR	0	0	(533)	(45,306)	272
273						273
274	**BATTLE MOUNTAIN**					274
275	(E3) QF Contract Energy	9,799	307,535	253,342	8,739,540	275
276	(E3) QF Contract Energy (Prior Month Adjustment)	493	13,050	4,239	151,417	276
277	(E3) Blended Rate Adjustment	0	(23,099)	0	(556,622)	277
278	(I) Reactive Power	0	0	0	0	278
279	Total BATTLE MOUNTAIN	10,292	297,486	257,581	8,334,335	279
280						280
281	**BEOWAWE**					281
282	(E1) QF Contract Energy	8,242	519,901	94,905	5,814,205	282
283	(E1) QF Contract Energy (Prior Month Adjustment)	255	(112)	2,405	171,713	283
284	Total BEOWAWE	8,497	519,790	97,310	5,985,917	284
285						285
286	**BOULDER SOLAR II**					286
287	(E3) QF Contract Energy	6,210	287,266	130,032	6,014,658	287
288	(E3) QF Contract Energy (Prior Month Adjustment)	(548)	(25,378)	(4,087)	(188,383)	288
289	Total BOULDER SOLAR II	5,662	261,888	125,945	5,826,274	289
290						290
291	**BURDETTE**					291
292	(E1) QF Contract Energy	10,447	608,961	111,132	6,185,859	292
293	(E1) QF Contract Energy (Prior Month Adjustment)	1,225	2,292	2,720	(838,823)	293
294	(E1) PC Replacement Costs	0	0	0	0	294
295	Total BURDETTE	11,672	611,253	113,852	5,347,036	295

SIERRA PACIFIC POWER COMPANY
SUMMARY OF PURCHASED POWER
FOR THE 12 MONTHS ENDED DECEMBER 31, 2023

Line No.	Distribution Of Purchased Power	December 2023 MWh	December 2023 Dollars	Total MWh	Total Dollars	Line No.
296						296
297	**DODGE FLAT**					297
298	(E3) QF Contract Energy	20,432	850,622	524,607	17,207,937	298
299	(E3) Contract Energy (Prior Month Adjustment)	(312)	(35,341)	4,366	910,726	299
300	(E3) Blended Rate Adjustment	0	(24,195)	0	(1,897,475)	300
301	(E3) Dodge Flat Delay Damages	0	0	0	0	301
302	Total DODGE FLAT	20,120	791,087	528,973	16,221,188	302
303						303
304	**FISH SPRINGS RANCH**					304
305	(E3) QF Contract Energy	7,440	379,851	249,742	9,224,280	305
306	(E3) Contract Energy (Prior Month Adjustment)	(161)	(17,866)	4,403	506,796	306
307	(E3) Blended Rate Adjustment	0	(49,563)	0	(1,930,862)	307
308	(E3) Fish Springs Delay Damages	0	0	0	0	308
309	Total FISH SPRINGS RANCH	7,279	312,422	254,145	7,800,214	309
310						310
311	**GALENA 3**					311
312	(E1) QF Contract Energy	9,136	614,118	92,629	5,723,902	312
313	(E1) QF Contract Energy (Prior Month Adjustment)	1,495	26,158	4,640	(978,774)	313
314	Total GALENA 3	10,631	640,276	97,269	4,745,128	314
315						315
316	**HOOPER**					316
317	(E2) QF Contract Energy	148	9,953	1,775	82,097	317
318	(E2) Contract Energy (Prior Month Adjustment)	(77)	(3,940)	(249)	(20,875)	318
319	Total HOOPER	71	6,013	1,526	61,223	319
320						320
321	**KINGSTON**					321
322	(E2) Contract Energy (Prior Month Adjustment)	0	0	0	0	322
323	(E2) QF Contract Energy	0	0	0	0	323
324	Total KINGSTON	0	0	0	0	324
325						325
326	**MILL CREEK**					326
327	(E2) QF Contract Energy	2	120	46	2,488	327
328	(E2) Contract Energy (Prior Month Adjustment)	(1)	38	(6)	(104)	328
329	Total MILL CREEK	1	157	40	2,384	329
330						330
331	**MOAPA (ARROW CANYON) SOLAR**					331
332	(E3) QF Contract Energy	21,934	466,321	433,622	4,842,556	332
333	(E3) Contract Energy (Prior Month Adjustment)	(680)	(7,230)	(6,571)	(69,928)	333
334	(E3) Delay Damages	0	0	0	(16,843,722)	334
335	Total MOAPA (ARROW CANYON) SOLAR	21,254	459,092	427,051	(12,071,094)	335
336						336
337	**NEVADA SOLAR ONE (SPPC)**					337
338	(E3) QF Contract Energy	614	127,617	30,111	6,260,050	338
339	(E3) QF Contract Energy (Prior Month Adjustment)	(87)	(18,252)	(372)	(77,758)	339
340	Total NEVADA SOLAR ONE (SPPC)	527	109,365	29,739	6,182,292	340
341						341
342	**NORTH VALLEY (ORNI 36)**					342
343	(E1) QF Contract Energy	22,180	1,273,136	160,391	8,824,460	343
344	(E1) QF Contract Energy (Prior Month Adjustment)	(366)	(20,965)	(443)	(35,716)	344
345	Total NORTH VALLEY (ORNI 36)	21,814	1,252,171	159,948	8,788,744	345
346						346
347	**STEAMBOAT 1 & 1A**					347
348	(E) Royalty Income - Reduce Exp	0	(15,212)	0	(122,858)	348
349	(E) Royalty Income - Reduce Exp (Prior Year Adjustment)	0	(2,025)	0	(3,636)	349
350	Total STEAMBOAT 1 & 1A	0	(17,237)	0	(126,494)	350
351						351
352	**STEAMBOAT 2**					352
353	(E1) QF Contract Energy	0	0	0	(12,038)	353
354	(E1) QF Contract Energy (Prior Month Adjustment)	0	0	2,395	55,703	354
355	(E1) QF Contract Capacity	0	0	0	0	355
356	(E1) QF Contract Capacity (Prior Month Adjustment)	0	0	0	12,038	356
357	Total STEAMBOAT 2	0	0	2,395	55,703	357
358						358

SIERRA PACIFIC POWER COMPANY
SUMMARY OF PURCHASED POWER
FOR THE 12 MONTHS ENDED DECEMBER 31, 2023

Line No.	Distribution Of Purchased Power	December 2023 MWh	December 2023 Dollars	Total MWh	Total Dollars	Line No.
359	**STEAMBOAT 3**					359
360	(E1) QF Contract Energy	0	0	0	(8,645)	360
361	(E1) QF Contract Energy (Prior Month Adjustment)	0	0	1,356	(35,435)	361
362	(E1) QF Contract Capacity	0	0	0	0	362
363	(E1) QF Contract Capacity (Prior Month Adjustment)	0	0	0	8,645	363
364	Total STEAMBOAT 3	0	0	1,356	(35,435)	364
365						365
366	**SWITCH STATION 2**					366
367	(E3) QF Contract Energy	8,327	375,478	196,133	8,976,521	367
368	(E3) QF Contract Energy (Prior Month Adjustment)	345	15,575	(9,520)	(424,261)	368
369	(E3) Late COD Penalty	0	0	0	0	369
370	Total SWITCH STATION 2	8,672	391,053	186,613	8,552,259	370
371						371
372	**TCID NEW LAHONTAN**					372
373	(E2) QF Contract Energy	0	0	19,350	522,457	373
374	(E2) Contract Energy (Prior Month Adjustment)	(231)	(6,238)	(2,801)	(75,633)	374
375	Total TCID NEW LAHONTAN	(231)	(6,238)	16,549	446,824	375
376						376
377	**TECHREN II**					377
378	(E3) QF Contract Energy	26,381	875,056	545,477	18,093,424	378
379	(E3) Contract Energy (Prior Month Adjustment)	(974)	(32,308)	(10,443)	(345,365)	379
380	(E3) Delay Damages	0	0	0	0	380
381	Total TECHREN II	25,407	842,748	535,034	17,748,060	381
382						382
383	**TECHREN IV**					383
384	(E3) QF Contract Energy	3,174	108,562	60,848	2,080,977	384
385	(E3) Contract Energy (Prior Month Adjustment)	(91)	(3,087)	(1,251)	(42,737)	385
386	(E3) Delay Damages	0	0	0	0	386
387	Total TECHREN IV	3,083	105,475	59,597	2,038,241	387
388						388
389	**TMWA Fleish**					389
390	(E2) Contract Energy	1,861	141,751	18,725	1,426,305	390
391	(E2) Contract Energy (Prior Month Adjustment)	10	808	751	57,318	391
392	Total TMWA Fleish	1,871	142,559	19,476	1,483,623	392
393						393
394	**TMWA Verdi**					394
395	(E2) Contract Energy	1,677	126,589	16,565	1,250,461	395
396	(E2) Contract Energy (Prior Month Adjustment)	30	2,327	1,253	93,822	396
397	Total TMWA Verdi	1,707	128,916	17,818	1,344,283	397
398						398
399	**TMWA Washoe**					399
400	(E2) Contract Energy	756	57,667	8,359	637,693	400
401	(E2) Contract Energy (Prior Month Adjustment)	204	15,584	2,166	161,585	401
402	Total TMWA Washoe	960	73,251	10,525	799,278	402
403						403
404	**TMWRF**					404
405	(E4) QF Contract Energy	0	4,000	0	49,958	405
406	(E4) QF Contract Energy (Prior Month Adjustment)	0	972	0	(3,298)	406
407	Total TMWRF	0	4,972	0	46,660	407
408						408

SIERRA PACIFIC POWER COMPANY
SUMMARY OF PURCHASED POWER
FOR THE 12 MONTHS ENDED DECEMBER 31, 2023

Line No.	Distribution Of Purchased Power	December 2023 MWh	December 2023 Dollars	Total MWh	Total Dollars	Line No.
409	**TURQUOISE**					409
410	(E2) QF Contract Energy	4,784	154,250	106,780	3,442,646	410
411	(E2) QF Contract Energy (Prior Month Adjustment)	10	323	(365)	(11,769)	411
412	Total TURQUOISE	4,794	154,573	106,415	3,430,876	412
413						413
414	**USG SAN EMIDIO**					414
415	(E1) QF Contract Energy	7,827	780,548	82,325	8,205,513	415
416	(E1) QF Contract Energy (Prior Month Adjustment)	855	85,309	29	7,542	416
417	Total USG SAN EMIDIO	8,682	865,856	82,354	8,213,055	417
418						418
419	**(F) MISC EXPENSES**					419
420	(F) CAISO Credit	0	0	0	0	420
421	(F) Excess QF RFP Bid Fees Collected	0	0	0	(160,075)	421
422	(F) Misc - other Tesla Motors, Inc. Availability Liquidated Damages	0	0	0	0	422
423	(F) Market Information Fees (I.C.E.)	0	4,341	0	55,932	423
424	(F) Market Information Fees (I.C.E.) - Prior Month Adjustment	0	0	0	(325)	424
425	(F) Misc Expense	0	799	0	14,334	425
426	(F) Miscellaneous(Fort Churchill Rent)	0	(15,307)	0	(15,307)	426
427	Total (F) MISC EXPENSES	0	(10,168)	0	(105,441)	427
428						428
429	**(5)Transmission Component of Sales**	0	3,567	0	299,367	429
430						430
431	**EIM Grid Management Fees**	0	22,960	0	385,610	431
432	**Other Transmission**	0	2,883	0	33,052	432
433	**(H) Transmission of Energy By Others (Account 565000 and 565005)**	0	25,843	0	418,662	433
434						434
435	**(6) Renewable Energy Credit Sales**	0	(165,268)	0	(1,167,594)	435
436						436
437	**Purch Pwr - Rooftop Solar Excess**	231	21,635	13,528	1,438,110	437
438						438
439	**NET COST OF PURCHASED POWER (Purchases Minus Sales)**	**259,108**	**16,316,129**	**4,487,718**	**278,954,161**	439

SIERRA PACIFIC POWER COMPANY
SUMMARY OF PURCHASED POWER
FOR THE 12 MONTHS ENDED DECEMBER 31, 2023

Line No.	Distribution Of Purchased Power	December 2023 MWh	December 2023 Dollars	Total MWh	Total Dollars	Line No.
440						440
441	**ACCOUNT DISTRIBUTION**					441
442						442
443	**SALES FOR RESALE**					443
444	(1) Non-Firm Energy (Sales for Resale)	0	0	0	0	444
445	(2) Short-Term Firm Energy (Sales for Resale)	(2,414)	(77,871)	(94,453)	(4,095,010)	445
446	(2) Short-Term Firm Energy (Sales for Resale) YTD Reclass	0	0	0	0	446
447	(3) Revenue Capacity Sales	0	0	0	0	447
448	(4) Energy Imbalance Sales & Losses	(2,639)	(147,842)	(26,592)	(1,647,233)	448
449	(4) Energy Imbalance Sales & Losses Penalty Distribution	0	0	0	0	449
450	(5) Transmission Component of Sales	0	3,567	0	299,367	450
451	(2) Misc - Joint Dispatch JE	0	0	(4,087)	(7,174,221)	451
452	(6) Renewable Energy Credit Sales	0	(165,268)	0	(1,167,594)	452
453	(7) Option Premium Revenue	0	0	0	0	453
454	(8) Revenue Resale Economy	0	0	0	0	454
455	**TOTAL SALES FOR RESALE**	(5,053)	(387,415)	(125,132)	(13,784,691)	455
456						456
457						457
458	**PURCHASED POWER**					458
459	(A) Economy Energy	0	0	0	0	459
460	(B) Short-Term Firm Energy	91,395	8,740,940	1,481,340	191,205,057	460
461	(C) Long-Term Firm Energy Contracts	0	0	0	0	461
462	(D) Short-Term/Long-Term Firm Contract Capacity	0	0	0	0	462
463	(E) QF Purchases	0	(17,237)	0	(126,494)	463
464	(E) QF Purchases - Renewable	43,596	1,825,757	616,778	2,948,986	464
465	(F) Other Expenses	0	(10,168)	0	(105,441)	465
466	(F) Miscellaneous(Fort Churchill Rent)	0	0	0	0	466
467	(G) Purch and sale of renewable energy credits per PUC order	0	0	0	0	467
468	(I) Reactive Power	0	0	0	0	468
469	SUBTOTAL PURCHASED POWER	134,991	10,539,292	2,098,117	193,922,108	469
470	QF Purchases - Variable lease pmnt	129,169	6,138,408	2,514,732	98,398,082	470
471	**TOTAL PURCHASED POWER**	264,160	16,677,700	4,612,850	292,320,190	471
472						472
473						473
474	(H)Transmission of Energy by Others	0	25,843	0	418,662	474
475						475
476	**TOTALS**	**259,108**	**16,316,129**	**4,487,718**	**278,954,161**	476
477		-	-			477
478	**Other Expenses (Solar Array O&M Lease)**					478
479	**Solar Array Rent**	0	0	0	0	479
480	**Solar Array Int**	0	0	0	0	480
481	**Solar Array Depr**	0	0	0	0	481
482	**Solar Array Maintenance**	0	0	0	0	482
483	**Total Expense (Solar Array)**	0	0	0	0	483
484						484
485	**GRAND TOTALS**	**259,108**	**16,316,129**	**4,487,718**	**278,954,161**	485
486						486

SIERRA PACIFIC POWER COMPANY
SUMMARY OF PURCHASED POWER
FOR THE 12 MONTHS ENDED DECEMBER 31, 2023

Line No.	Distribution Of Purchased Power	December 2023 MWh	December 2023 Dollars	Total MWh	Total Dollars	Line No.
487						487
488	**ANALYSIS TIE OUT**					488
489	(5) Transmission Component of Sales (447010)	0	(3,567)	0	(299,367)	489
490	(1) Option Premium Revenue (447041)	0	0	0	0	490
491	(1) Allegro Sales (447042)	(2,377)	(72,559)	(93,381)	(3,709,262)	491
492	(1) JDA Transfer Payment (447043)	0	0	(4,087)	(7,174,221)	492
493	**TOTAL REVENUE**	**(2,377)**	**(76,125)**	**(97,468)**	**(11,182,851)**	493
494	Purchases (Allegro)	14,580	914,227	1,107,377	168,483,961	494
495	Nevada Gold Energy	0	0	5,920	414,400	495
496	Purchases (Other) & CalPeco	0	74,973	159	914,953	496
497	QF's	0	(17,237)	0	(126,494)	497
498	Renewable Energy	43,596	1,825,757	616,778	2,948,986	498
499	Joint Dispatch Transfer Payment	92,946	8,391,333	846,290	33,705,133	499
500	Options	0	0	0	0	500
501	Miscellaneous	0	(10,168)	0	(105,441)	501
502	Subtotal purchased power (555000)	151,122	11,178,885	2,576,524	206,235,498	502
503	QF's Renewable Energy - Variable Lease Pmnt (555002)	129,169	6,138,408	2,514,732	98,398,082	503
504	Rooftop Solar Excess (555003)	231	21,635	13,528	1,438,110	504
505	EIM (555005)	(16,362)	(661,228)	(491,934)	(13,751,500)	505
506	REC Sales (555010)	0	(165,268)	0	(1,167,594)	506
507	**TOTAL PURCHASED POWER**	264,160	16,512,432	4,612,850	291,152,595	507
508	(2) Short-Term Firm Energy (Sales for Resale) (447040)	(37)	(1,746)	(1,072)	(86,380)	508
509	(J) Transmission of Energy by Others (565000/565005)	0	25,843	0	418,662	509
510				0	0	510
511	**TOTAL PER ANALYSIS**	**264,123**	**16,536,529**	**4,611,778**	**291,484,877**	511
512	**Regulatory Adjustments**					512
513	**Imbalance Sales and Losses**	(2,639)	(147,842)	(26,592)	(1,647,233)	513
514	**Allegro/Transfer Sales**	(2,377)	(72,559)	(97,468)	(10,883,483)	514
515	**Options**	0	0	0	0	515
516	**Total Purchased Power Analysis 555, 565 and 447**	259,108	16,316,129	4,487,718	278,954,161	516

EXHIBIT F

SIERRA PACIFIC POWER COMPANY
d/b/a NV ENERGY
EARNED RATE OF RETURN FOR NEVADA ELECTRIC JURISDICTION - 2023
USING END OF PERIOD RATE BASE
($000)

Ln No	(a) Development of Return	(b) March	(c) June	(d) September	(e) December	Ln No
1	Operating Revenues	$ 1,048,097	$ 1,117,740	$ 1,163,693	$ 1,163,990	1
2						2
3	Operating Expenses					3
4	O&M Expense	740,270	797,052	831,238	837,646	4
5	Depreciation & Amortization Expense	160,697	165,728	169,499	168,463	5
6	Taxes Other Than Income	24,442	24,586	24,793	24,902	6
7	Deferred Income Taxes	20,986	(5,117)	(19,427)	(41,477)	7
8	Amortization of ITC	(3,800)	(4,298)	(4,809)	(5,297)	8
9	Federal Income Tax	(8,617)	19,868	37,446	55,335	9
10	Total Operating Expenses	933,978	997,819	1,038,739	1,039,572	10
11						11
12	Operating Income	114,119	119,921	124,954	124,418	12
13						13
14	Adjustments to Operating Income	-	-	-	-	14
15						15
16	Adjusted Operating Income	$ 114,119	$ 119,921	$ 124,954	$ 124,418	16
17						17
18						18
19	Rate Base					19
20	Gross Plant in Service	$ 4,341,825	$ 4,350,021	$ 4,341,966	$ 4,399,810	20
21	Accum. Provision for Depr. & Amort.	(1,810,429)	(1,833,451)	(1,843,869)	(1,856,297)	21
22	Net Plant in Service	2,531,397	2,516,571	2,498,097	2,543,514	22
23						23
24	Additions (Deductions) to Net Plant	(416,851)	(406,645)	(375,988)	(365,226)	24
25						25
26	Rate Base	$ 2,114,546	$ 2,109,925	$ 2,122,109	$ 2,178,288	26
27						27
28	Earned Rate of Return	5.40%	5.68%	5.89%	5.71%	28
29						29
30	Authorized Rate of Return per Docket No. 22-06014					30
31	with incentives	6.98%	6.98%	6.98%	6.98%	31
32	without incentives	6.95%	6.95%	6.95%	6.95%	32

Exhibit F
Page 2 of 2
Naughton

SIERRA PACIFIC POWER COMPANY
d/b/a NV ENERGY
EARNED RATE OF RETURN FOR NEVADA ELECTRIC JURISDICTION - 2023
USING AVERAGE RATE BASE
($000)

Ln No	(a) Development of Return	(b) 1 January	(c) 2 February	(d) 3 March	(e) 4 April	(f) 5 May	(g) 6 June	(h) 7 July	(i) 8 August	(j) 9 September	(k) 10 October	(l) 11 November	(m) 12 December	Ln No
1	Operating Revenues	$ 1,003,976	$ 1,022,108	$ 1,048,097	$ 1,070,778	$ 1,090,712	$ 1,117,740	$ 1,139,302	$ 1,151,680	$ 1,163,693	$ 1,158,837	$ 1,161,923	$ 1,163,990	1
2														2
3	Operating Expenses													3
4	O&M Expense	703,448	717,227	740,270	761,888	780,866	797,051	811,644	820,779	831,237	831,324	835,422	837,648	4
5	Depreciation & Amortization Expense	153,190	156,933	160,699	162,695	164,361	165,733	166,919	168,398	169,506	169,483	168,965	168,517	5
6	Taxes Other Than Income	24,195	24,337	24,475	24,573	24,569	24,622	24,604	24,814	24,813	24,811	24,908	24,912	6
7	Deferred Income Taxes	29,648	27,264	20,986	13,077	2,313	(5,117)	(9,850)	(13,762)	(19,427)	(23,386)	(30,868)	(41,477)	7
8	Amortization of ITC	(3,467)	(3,633)	(3,800)	(3,967)	(4,132)	(4,298)	(4,465)	(4,632)	(4,809)	(4,975)	(5,143)	(5,297)	8
9	Federal Income Tax	(17,147)	(14,897)	(8,504)	(1,154)	10,392	19,879	25,930	28,354	37,408	40,666	46,470	55,446	9
10	Total Operating Expenses	889,865	907,232	934,126	957,113	978,370	997,870	1,014,781	1,023,951	1,038,726	1,037,922	1,039,753	1,039,750	10
11														11
12	Operating Income	114,111	114,876	113,972	113,665	112,342	119,870	124,521	127,729	124,967	120,915	122,170	124,240	12
13														13
14	Adjustments to Operating Income	-	-	-	-	-	-	-	-	-	-	-	-	14
15														15
16	Adjusted Operating Income	$ 114,111	$ 114,876	$ 113,972	$ 113,665	$ 112,342	$ 119,870	$ 124,521	$ 127,729	$ 124,967	$ 120,915	$ 122,170	$ 124,240	16
17														17
18														18
19	Rate Base													19
20	Gross Plant in Service	$ 4,242,028	$ 4,264,380	$ 4,285,747	4,304,047	$ 4,296,707	$ 4,303,001	$ 4,308,488	$ 4,311,573	$ 4,309,487	$ 4,311,105	$ 4,315,727	$ 4,324,178	20
21	Accum. Provision for Depr. & Amort.	(1,746,113)	(1,755,046)	(1,764,091)	(1,772,149)	(1,772,557)	(1,778,523)	$ (1,784,076)	$ (1,788,899)	$ (1,793,165)	(1,797,897)	(1,804,621)	(1,811,183)	21
22	Net Plant in Service	2,495,916	2,509,334	2,521,656	2,531,899	2,524,150	2,524,479	2,524,412	2,522,674	2,516,322	2,513,208	2,511,106	2,512,995	22
23														23
24	Additions (Deductions) to Net Plant	(444,203)	(441,804)	(440,492)	(438,386)	(425,580)	(420,394)	(407,824)	(398,647)	(384,517)	(377,976)	(372,938)	(364,620)	24
25														25
26	Rate Base	$ 2,051,712	$ 2,067,530	$ 2,081,164	$ 2,093,513	$ 2,098,570	$ 2,104,085	$ 2,116,588	$ 2,124,027	$ 2,131,805	$ 2,135,232	$ 2,138,168	$ 2,148,375	26
27														27
28	Earned Rate of Return	5.56%	5.56%	5.48%	5.43%	5.35%	5.70%	5.88%	6.01%	5.86%	5.66%	5.71%	5.78%	28
29														29
30	Authorized Rate of Return per Docket No. 22-06014													30
31	with incentives	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	31
32	without incentives	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	6.95%	32
33														33
34														34
35	Note: Reflects average rate base in compliance with NAC 704.9523 (3) (c)													35

EXHIBIT G

TABLE 1
SIERRA PACIFIC POWER COMPANY
d/b/a NV Energy
ELECTRIC DEPARTMENT - NEVADA
ANNUAL SUMMARY - REPR EE NDPP TRED
PROPOSED CHANGE IN TOTAL REVENUE
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

Ln No	(a) RATE SCHEDULE		(b) Recorded kWh Sales	(c) Lamp/ Customer Count	(d) BTGR, BTER, DEAA & ESDR	(e) Present Rate Revenues REPR, EE, NDPP, TRED & ESPC	(f) TOTAL	(g) Proposed Rate Revenues REPR, EE, NDPP, TRED & ESPC	(h) TOTAL	(i) Dollar Change Total Revenues	(j) Percent Change Total Revenues	(k) PROPOSED MONTHLY INCR / (DECR)	Ln No
										(h) - (f)	(i) / (f)	(i) / (c)	
1	Domestic Service	D-1	2,182,941,210	2,865,889	$ 323,773,466	$ 10,827,391	$ 334,600,857	$ 9,364,815	$ 333,138,281	$ (1,462,576)	(0.44)%	(0.51)	1
2	Domestic Multi-Family Service	DM-1	452,335,125	1,001,899	64,635,945	2,198,347	66,834,292	1,895,283	66,531,228	(303,064)	(0.45)%	(0.30)	2
3	Domestic Service ESAP	D-1 ESAP	5,934,235	8,133	810,584	29,433	840,017	25,457	836,041	(3,976)	(0.47)%	(0.49)	3
4	Domestic Multi-Family Service ESAP	DM-1 ESAP	1,951,832	4,238	252,929	9,486	262,415	8,178	261,107	(1,308)	(0.50)%	(0.31)	4
5	Total Residential - Non-TOU		2,643,162,402	3,880,159	389,472,924	13,064,657	402,537,581	11,293,733	400,766,657	(1,770,924)	(0.44)%	(0.46)	5
6													6
7	Optional Domestic Service - TOU	OD-1 TOU	24,910,460	25,901	3,375,836	123,553	3,499,389	106,867	3,482,703	(16,686)	(0.48)%	(0.64)	7
8	Optional Domestic Service - TOU ESAP	OD-1 TOU ESAP	259,771	347	29,494	1,289	30,783	1,116	30,610	(173)	(0.56)%	(0.50)	8
9	Optional Domestic Multi-Family Service - TOU	ODM-1 TOU	578,297	910	68,183	2,810	70,993	2,422	70,605	(388)	(0.55)%	(0.43)	9
10	Optional Domestic Multi-Family Service - TOU ESAP	ODM-1 TOU ESAP	26,637	29	2,310	129	2,439	112	2,422	(17)	(0.70)%	(0.59)	10
11	Total Residential - TOU		25,775,165	27,187	3,475,823	127,781	3,603,604	110,517	3,586,340	(17,264)	(0.48)%	(0.64)	11
12													12
13	**Total Residential**		**2,668,937,567**	**3,907,346**	**392,948,747**	**13,192,438**	**406,141,185**	**11,404,250**	**404,352,997**	**(1,788,188)**	**(0.44)%**	**(0.46)**	13
14													14
15	Small General Service	GS-1	654,145,819	509,890	84,062,417	2,773,575	86,835,992	2,335,299	86,397,716	(438,276)	(0.50)%	(0.86)	15
16	Small General Service ESAP	GS-1 ESAP	503,211	366	57,302	2,133	59,435	1,795	59,097	(338)	(0.57)%	(0.92)	16
17	Optional General Service - Time-of-Use	OGS-1 TOU	25,885,529	20,126	3,186,026	108,719	3,294,745	91,117	3,277,143	(17,602)	(0.53)%	(0.87)	17
18	Optional General Service - Time-of-Use ESAP	OGS-1 TOU ESAP	22,603	11	2,102	95	2,197	79	2,181	(16)	(0.73)%	(1.45)	18
19	Small General Service - SSR	GS-1 SSR	20,993	48	4,476	90	4,566	75	4,551	(15)	(0.33)%	(0.31)	19
20	Wireless Communication Service	WCS	82,500	12	8,626	350	8,976	294	8,920	(56)	(0.62)%	(4.67)	20
21	Irrigation Service	IS-1	36,795,854	10,501	5,436,942	189,499	5,626,441	166,686	5,603,628	(22,813)	(0.41)%	(2.17)	21
22	Interruptible Irrigation Service	IS-2	100,556,728	-	7,870,576	75,418	7,945,994	75,418	7,945,994	-	- %	-	22
23	City of Elko Water Pumping	WP	6,895,811	11	843,828	30,755	874,583	26,135	869,963	(4,620)	(0.53)%	(420.00)	23
24	Total Small General Service		824,909,048	540,965	101,472,295	3,180,634	104,652,929	2,696,898	104,169,193	(483,736)	(0.46)%	(0.89)	24
25													25
26	Medium General Service -Secondary	GS-2S	1,346,620,955	41,087	155,489,748	5,723,140	161,212,888	4,820,904	160,310,652	(902,236)	(0.56)%	(21.96)	26
27	Medium General Service - Primary	GS-2P	50,631,272	483	5,221,613	208,601	5,430,214	175,184	5,396,797	(33,417)	(0.62)%	(69.19)	27
28	Medium General Service - Transmission	GS-2T	16,257,138	160	1,566,970	62,428	1,629,398	51,210	1,618,180	(11,218)	(0.69)%	(70.11)	28
29	Medium General Service - TOU - Secondary	GS-2S TOU	402,570,048	1,617	46,315,841	1,763,257	48,079,098	1,497,561	47,813,402	(265,696)	(0.55)%	(164.31)	29
30	Medium General Service - TOU - Primary	GS-2P TOU	59,451,036	173	6,192,989	255,640	6,448,629	215,807	6,408,796	(39,833)	(0.62)%	(230.25)	30
31	Medium General Service - TOU - Transmission	GS-2T TOU	12,297,467	36	1,287,389	49,313	1,336,702	41,073	1,328,462	(8,240)	(0.62)%	(228.89)	31
32	Optional Medium General Service - TOU - Secondary	OGS-2S TOU	296,804,743	8,754	34,601,174	1,267,356	35,868,530	1,068,498	35,669,672	(198,858)	(0.55)%	(22.72)	32
33	Optional Medium General Service - TOU - Primary	OGS-2P TOU	2,948,209	24	300,876	12,147	313,023	10,200	311,076	(1,947)	(0.62)%	(81.13)	33
34	Optional Medium General Service - TOU - Transmission	OGS-2T TOU	-	-	-	-	-	-	-	-	- %	-	34
35	Medium General Service - Secondary - SSR	GS-2S SSR	-	-	-	-	-	-	-	-	- %	-	35
36	Medium General Service - Primary - SSR	GS-2P SSR	3,870	12	19,121	16	19,137	13	19,134	(3)	(0.02)%	(0.25)	36
37	Medium General Service - Transmission - SSR	GS-2T SSR	1,037,196	60	130,046	3,984	134,030	3,268	133,314	(716)	(0.53)%	(11.93)	37
38	Medium General Service - Secondary TOU - LSR	GS-2S TOU LSR	-	-	-	-	-	-	-	-	- %	-	38
39	Medium General Service - Primary TOU - LSR	GS-2P TOU LSR	-	-	-	-	-	-	-	-	- %	-	39
40	Medium General Service - Transmission TOU - LSR	GS-2T TOU LSR	2,410,664	77	383,982	9,667	393,649	8,050	392,032	(1,617)	(0.41)%	(21.00)	40
41	Total Medium General Service		2,191,032,598	52,483	251,509,749	9,355,549	260,865,298	7,891,768	259,401,517	(1,463,781)	(0.56)%	(27.89)	41
42													42
43	Large General Service - Secondary	GS-3S	346,287,453	482	38,698,223	1,412,852	40,111,075	1,246,635	39,944,858	(166,217)	(0.41)%	(344.85)	43
44	Large General Service - Primary	GS-3P	444,104,713	349	48,198,850	1,740,890	49,939,740	1,509,956	49,708,806	(230,934)	(0.46)%	(661.70)	44
45	Large General Service - Transmission	GS-3T	1,187,130,339	216	111,717,426	4,760,392	116,477,818	3,691,975	115,409,401	(1,068,417)	(0.92)%	(4,946.38)	45
46	Large General Service - Secondary - LSR	GS-3S LSR	-	-	-	-	-	-	-	-	- %	-	46
47	Large General Service - Primary - LSR	GS-3P LSR	1,376,724	12	161,921	5,397	167,318	4,681	166,602	(716)	(0.43)%	(59.67)	47
48	Large General Service - Transmission - LSR	GS-3T LSR	667,769,899	197	62,873,357	2,677,758	65,551,115	2,076,764	64,950,121	(600,994)	(0.92)%	(3,050.73)	48
49	Total Large General Service		2,646,669,128	1,256	261,649,777	10,597,289	272,247,066	8,530,011	270,179,788	(2,067,278)	(0.76)%	(1,645.92)	49
50													50
51	Large Transmission Service	GS-4	24,522,921	12	2,381,997	101,036	2,483,033	85,094	2,467,091	(15,942)	(0.64)%	(1,328.50)	51
52													52
53	Street Lighting Service	SL	10,671,624	309,876	4,663,198	41,300	4,704,498	34,257	4,697,455	(7,043)	(0.15)%	(0.02)	53
54	Outdoor Lighting Service	OLS	4,521,264	82,860	1,621,360	18,222	1,639,582	15,145	1,636,505	(3,077)	(0.19)%	(0.04)	54
55	Total Lighting Service		15,192,888	392,736	6,284,558	59,522	6,344,080	49,402	6,333,960	(10,120)	(0.16)%	(0.03)	55
56													56
57	**Total Non-Residential**		**5,702,326,583**	**987,452**	**623,298,376**	**23,294,030**	**646,592,406**	**19,253,173**	**642,551,549**	**(4,040,857)**	**(0.62)%**	**(4.09)**	57
58													58
59	**Total - all classes**		**8,371,264,150**	**4,894,798**	**1,016,247,123**	**36,486,468**	**1,052,733,591**	**30,657,423**	**1,046,904,546**	**(5,829,045)**	**(0.55)%**	**(1.19)**	59
60													60
61	Unbilled	Unbilled	(23,691,724)	-	(1,644,443)	(59,466)	(1,703,909)	(42,408)	(1,686,851)	17,058	(1.00)%	-	61
62													62
63	**Total - all classes with Unbilled**		**8,347,572,426**	**4,894,798**	**1,014,602,680**	**36,427,002**	**1,051,029,682**	**30,615,015**	**1,045,217,695**	**(5,811,987)**	**(0.55)%**	**(1.19)**	63
64													64
65	Distribution Only Service	DOS	2,807,055,785	300	4,897,626	2,105,294	7,002,920	2,105,294	7,002,920	-	- %	-	65
66													66
67	Unbilled - DOS	Unbilled - DOS	22,117,568	-	221	16,588	16,809	16,588	16,809	-	- %	-	67
68													68
69	**Total Distribution Only Service**		**2,829,173,353**	**300**	**4,897,847**	**2,121,882**	**7,019,729**	**2,121,882**	**7,019,729**	**-**	**- %**	**-**	69
70													70
71	**Total - All Classes With DOS**		**11,176,745,779**	**4,895,098**	**$ 1,019,500,527**	**$ 38,548,884**	**$ 1,058,049,411**	**$ 32,736,897**	**$ 1,052,237,424**	**$ (5,811,987)**	**(0.55)%**	**(1.19)**	71
72													72

73 Notes: 73
74 1) Unbilled sales are not used to calculate BTGR, Base EEPR and Base EEIR revenues. 74
75 2) IS-2 has a separate BTER rate and is not subject to DEAA & REPR. 75

TABLE 2
SIERRA PACIFIC POWER COMPANY
d/b/a NV Energy
PRESENT RATE REVENUE: BASE TARIFF GENERAL RATE ("BTGR")
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

Ln No	(a) Rate Schedule Description		(b) BTGR Revenue Present	(c) BTGR Revenue Proposed	(d) Difference [(c)-(b)]	(e) Percent Change in Component [(d)/(b)]	(f) Percent Component Rev to Total Present Rev	(g) Percentage Change to Total Revenue [(e)*(f)]	Ln No
1	Domestic Service	D-1	$ 172,255,516	$ 172,255,516	$ -	- %	51.48 %	- %	1
2	Domestic Multi-Family Service	DM-1	33,239,365	33,239,365	-	- %	49.73 %	- %	2
3	Domestic Service ESAP	D-1 ESAP	475,537	475,537	-	- %	56.61 %	- %	3
4	Domestic Multi-Family Service ESAP	DM-1 ESAP	142,728	142,728	-	- %	54.39 %	- %	4
5	Total Residential - Non-TOU		206,113,146	206,113,146	-	- %	51.20 %	- %	5
6									6
7	Optional Domestic Service - TOU	OD-1 TOU	1,646,804	1,646,804	-	- %	47.06 %	- %	7
8	Optional Domestic Service - TOU ESAP	OD-1 TOU ESAP	14,827	14,827	-	- %	48.17 %	- %	8
9	Optional Domestic Multi-Family Service - TOU	ODM-1 TOU	28,044	28,044	-	- %	39.50 %	- %	9
10	Optional Domestic Multi-Family Service - TOU ESAP	ODM-1 TOU ESAP	806	806	-	- %	33.05 %	- %	10
11	Total Residential - TOU		1,690,481	1,690,481	-	- %	46.91 %	- %	11
12									12
13	**Total Residential**		**207,803,627**	**207,803,627**	**-**	**- %**	**51.17 %**	**- %**	13
14									14
15	Small General Service	GS-1	38,658,156	38,658,156	-	- %	44.52 %	- %	15
16	Small General Service ESAP	GS-1 ESAP	28,891	28,891	-	- %	48.61 %	- %	16
17	Optional General Service - Time-of-Use	OGS-1 TOU	1,389,311	1,389,311	-	- %	42.17 %	- %	17
18	Optional General Service - Time-of-Use ESAP	OGS-1 TOU ESAP	826	826	-	- %	37.60 %	- %	18
19	Small General Service - SSR	GS-1 SSR	3,019	3,019	-	- %	66.12 %	- %	19
20	Wireless Communication Service	WCS	2,899	2,899	-	- %	32.30 %	- %	20
21	Irrigation Service	IS-1	2,882,942	2,882,942	-	- %	51.24 %	- %	21
22	Interruptible Irrigation Service	IS-2	-	-	-	- %	- %	- %	22
23	City of Elko Water Pumping	WP	365,190	365,190	-	- %	41.76 %	- %	23
24	Total Small General Service		43,331,234	43,331,234	-	- %	41.40 %	- %	24
25									25
26	Medium General Service -Secondary	GS-2S	62,020,787	62,020,787	-	- %	38.47 %	- %	26
27	Medium General Service - Primary	GS-2P	1,707,297	1,707,297	-	- %	31.44 %	- %	27
28	Medium General Service - Transmission	GS-2T	438,561	438,561	-	- %	26.92 %	- %	28
29	Medium General Service - TOU - Secondary	GS-2S TOU	18,373,453	18,373,453	-	- %	38.22 %	- %	29
30	Medium General Service - TOU - Primary	GS-2P TOU	2,066,492	2,066,492	-	- %	32.05 %	- %	30
31	Medium General Service - TOU - Transmission	GS-2T TOU	433,822	433,822	-	- %	32.45 %	- %	31
32	Optional Medium General Service - TOU - Secondary	OGS-2S TOU	13,999,958	13,999,958	-	- %	39.03 %	- %	32
33	Optional Medium General Service - TOU - Primary	OGS-2P TOU	96,241	96,241	-	- %	30.75 %	- %	33
34	Optional Medium General Service - TOU - Transmission	OGS-2T TOU	-	-	-	- %	- %	- %	34
35	Medium General Service - Secondary - SSR	GS-2S SSR	-	-	-	- %	- %	- %	35
36	Medium General Service - Primary - SSR	GS-2P SSR	18,853	18,853	-	- %	98.52 %	- %	36
37	Medium General Service - Transmission - SSR	GS-2T SSR	58,055	58,055	-	- %	43.31 %	- %	37
38	Medium General Service - Secondary TOU - LSR	GS-2S TOU LSR	-	-	-	- %	- %	- %	38
39	Medium General Service - Primary TOU - LSR	GS-2P TOU LSR	-	-	-	- %	- %	- %	39
40	Medium General Service - Transmission TOU - LSR	GS-2T TOU LSR	216,658	216,658	-	- %	55.04 %	- %	40
41	Total Medium General Service		99,430,177	99,430,177	-	- %	38.12 %	- %	41
42									42
43	Large General Service - Secondary	GS-3S	14,662,410	14,662,410	-	- %	36.55 %	- %	43
44	Large General Service - Primary	GS-3P	17,373,541	17,373,541	-	- %	34.79 %	- %	44
45	Large General Service - Transmission	GS-3T	29,318,709	29,318,709	-	- %	25.17 %	- %	45
46	Large General Service - Secondary - LSR	GS-3S LSR	-	-	-	- %	- %	- %	46
47	Large General Service - Primary - LSR	GS-3P LSR	66,362	66,362	-	- %	39.66 %	- %	47
48	Large General Service - Transmission - LSR	GS-3T LSR	16,523,449	16,523,449	-	- %	25.21 %	- %	48
49	Total Large General Service		77,944,471	77,944,471	-	- %	28.63 %	- %	49
50									50
51	Large Transmission Service	GS-4	679,861	679,861	-	- %	27.38 %	- %	51
52									52
53	Street Lighting Service	SL	3,922,480	3,922,480	-	- %	83.38 %	- %	53
54	Outdoor Lighting Service	OLS	1,307,540	1,307,540	-	- %	79.75 %	- %	54
55	Total Lighting Service		5,230,020	5,230,020	-	- %	82.44 %	- %	55
56									56
57	**Total Non-Residential**		**226,615,763**	**226,615,763**	**-**	**- %**	**35.05 %**	**- %**	57
58									58
59	**Total - all classes**		**434,419,390**	**434,419,390**	**-**	**- %**	**41.27 %**	**- %**	59
60									60
61	Unbilled	Unbilled	-	-	-	- %	- %	- %	61
62									62
63	**Total - all classes with Unbilled**		**434,419,390**	**434,419,390**	**-**	**- %**	**41.33 %**	**- %**	63
64									64
65	Distribution Only Service	DOS	4,869,554	4,869,554	-	- %	69.54 %	- %	65
66									66
67	Unbilled - DOS	Unbilled - DOS	-	-	-	- %	- %	- %	67
68									68
69	Total Distribution Only Service		4,869,554	4,869,554	-	- %	69.37 %	- %	69
70									70
71	**Total - All Classes With DOS**		**$ 439,288,944**	**$ 439,288,944**	**$ -**	**- %**	**41.52 %**	**- %**	71

TABLE 3
SIERRA PACIFIC POWER COMPANY
d/b/a NV Energy
PRESENT & PROPOSED RATE REVENUE: BTER
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	
			BTER Revenue			Percent Change		Percentage Change	
Ln No	Rate Schedule Description		Present	Proposed	Difference [(c)-(b)]	in Component [(d)/(b)]	Percent Component Rev to Total Present Rev	to Total Revenue [(e)*(f)]	Ln No
1	Domestic Service	D-1	$ 140,581,414	$ 140,581,414	$ -	- %	42.01 %	- %	1
2	Domestic Multi-Family Service	DM-1	29,130,382	29,130,382	-	- %	43.59 %	- %	2
3	Domestic Service ESAP	D-1 ESAP	334,988	334,988	-	- %	39.88 %	- %	3
4	Domestic Multi-Family Service ESAP	DM-1 ESAP	110,181	110,181	-	- %	41.99 %	- %	4
5	Total Residential - Non-TOU		170,156,965	170,156,965	-	- %	42.27 %	- %	5
6									6
7	Optional Domestic Service - TOU	OD-1 TOU	1,604,230	1,604,230	-	- %	45.84 %	- %	7
8	Optional Domestic Service - TOU ESAP	OD-1 TOU ESAP	14,664	14,664	-	- %	47.64 %	- %	8
9	Optional Domestic Multi-Family Service - TOU	ODM-1 TOU	37,242	37,242	-	- %	52.46 %	- %	9
10	Optional Domestic Multi-Family Service - TOU ESAP	ODM-1 TOU ESAP	1,504	1,504	-	- %	61.66 %	- %	10
11	Total Residential - TOU		1,657,640	1,657,640	-	- %	46.00 %	- %	11
12									12
13	**Total Residential**		**171,814,605**	**171,814,605**	**-**	**- %**	**42.30 %**	**- %**	13
14									14
15	Small General Service	GS-1	42,126,991	42,126,991	-	- %	48.51 %	- %	15
16	Small General Service ESAP	GS-1 ESAP	28,406	28,406	-	- %	47.79 %	- %	16
17	Optional General Service - Time-of-Use	OGS-1 TOU	1,667,028	1,667,028	-	- %	50.60 %	- %	17
18	Optional General Service - Time-of-Use ESAP	OGS-1 TOU ESAP	1,276	1,276	-	- %	58.08 %	- %	18
19	Small General Service - SSR	GS-1 SSR	1,352	1,352	-	- %	29.61 %	- %	19
20	Wireless Communication Service	WCS	5,313	5,313	-	- %	59.19 %	- %	20
21	Irrigation Service	IS-1	2,369,653	2,369,653	-	- %	42.12 %	- %	21
22	Interruptible Irrigation Service	IS-2	7,869,570	7,869,570	-	- %	99.04 %	- %	22
23	City of Elko Water Pumping	WP	444,090	444,090	-	- %	50.78 %	- %	23
24	Total Small General Service		54,513,679	54,513,679	-	- %	52.09 %	- %	24
25									25
26	Medium General Service -Secondary	GS-2S	86,722,390	86,722,390	-	- %	53.79 %	- %	26
27	Medium General Service - Primary	GS-2P	3,260,654	3,260,654	-	- %	60.05 %	- %	27
28	Medium General Service - Transmission	GS-2T	1,046,960	1,046,960	-	- %	64.25 %	- %	28
29	Medium General Service - TOU - Secondary	GS-2S TOU	25,925,511	25,925,511	-	- %	53.92 %	- %	29
30	Medium General Service - TOU - Primary	GS-2P TOU	3,828,647	3,828,647	-	- %	59.37 %	- %	30
31	Medium General Service - TOU - Transmission	GS-2T TOU	791,957	791,957	-	- %	59.25 %	- %	31
32	Optional Medium General Service - TOU - Secondary	OGS-2S TOU	19,114,225	19,114,225	-	- %	53.29 %	- %	32
33	Optional Medium General Service - TOU - Primary	OGS-2P TOU	189,865	189,865	-	- %	60.66 %	- %	33
34	Optional Medium General Service - TOU - Transmission	OGS-2T TOU	-	-	-	- %	- %	- %	34
35	Medium General Service - Secondary - SSR	GS-2S SSR	-	-	-	- %	- %	- %	35
36	Medium General Service - Primary - SSR	GS-2P SSR	249	249	-	- %	1.30 %	- %	36
37	Medium General Service - Transmission - SSR	GS-2T SSR	66,795	66,795	-	- %	49.84 %	- %	37
38	Medium General Service - Secondary TOU - LSR	GS-2S TOU LSR	-	-	-	- %	- %	- %	38
39	Medium General Service - Primary TOU - LSR	GS-2P TOU LSR	-	-	-	- %	- %	- %	39
40	Medium General Service - Transmission TOU - LSR	GS-2T TOU LSR	155,247	155,247	-	- %	39.44 %	- %	40
41	Total Medium General Service		141,102,500	141,102,500	-	- %	54.09 %	- %	41
42									42
43	Large General Service - Secondary	GS-3S	22,300,912	22,300,912	-	- %	55.60 %	- %	43
44	Large General Service - Primary	GS-3P	28,600,344	28,600,344	-	- %	57.27 %	- %	44
45	Large General Service - Transmission	GS-3T	76,451,194	76,451,194	-	- %	65.64 %	- %	45
46	Large General Service - Secondary - LSR	GS-3S LSR	-	-	-	- %	- %	- %	46
47	Large General Service - Primary - LSR	GS-3P LSR	88,661	88,661	-	- %	52.99 %	- %	47
48	Large General Service - Transmission - LSR	GS-3T LSR	43,004,381	43,004,381	-	- %	65.60 %	- %	48
49	Total Large General Service		170,445,492	170,445,492	-	- %	62.61 %	- %	49
50									50
51	Large Transmission Service	GS-4	1,579,276	1,579,276	-	- %	63.60 %	- %	51
52									52
53	Street Lighting Service	SL	687,253	687,253	-	- %	14.61 %	- %	53
54	Outdoor Lighting Service	OLS	291,169	291,169	-	- %	17.76 %	- %	54
55	Total Lighting Service		978,422	978,422	-	- %	15.42 %	- %	55
56									56
57	**Total Non-Residential**		**368,619,369**	**368,619,369**	**-**	**- %**	**57.01 %**	**- %**	57
58									58
59	**Total - all classes**		**540,433,974**	**540,433,974**	**-**	**- %**	**51.34 %**	**- %**	59
60									60
61	Unbilled	Unbilled	(1,525,747)	(1,525,747)	-	- %	89.54 %	- %	61
62									62
63	**Total - all classes with Unbilled**		**538,908,227**	**538,908,227**	**-**	**- %**	**51.27 %**	**- %**	63
64									64
65	Distribution Only Service	DOS	-	-	-	- %	- %	- %	65
66									66
67	Unbilled - DOS	Unbilled - DOS	-	-	-	- %	- %	- %	67
68									68
69	Total Distribution Only Service		-	-	-	- %	- %	- %	69
70									70
71	**Total - All Classes With DOS**		**$ 538,908,227**	**$ 538,908,227**	**$ -**	**- %**	**50.93 %**	**- %**	71

TABLE 4
SIERRA PACIFIC POWER COMPANY
d/b/a NV Energy
PRESENT & PROPOSED RATE REVENUE: DEAA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

Ln No	(a) Rate Schedule Description		(b) DEAA Revenue Present	(c) DEAA Revenue Proposed	(d) Difference [(c)-(b)]	(e) Percent Change in Component [(d)/(b)]	(f) Percent Component Rev to Total Present Rev	(g) Percentage Change to Total Revenue [(e)*(f)]	Ln No
1	Domestic Service	D-1	$ 10,914,706	$ 10,914,706	$ -	- %	3.26 %	- %	1
2	Domestic Multi-Family Service	DM-1	2,261,675	2,261,675	-	- %	3.38 %	- %	2
3	Domestic Service ESAP	D-1 ESAP	-	-	-	- %	- %	- %	3
4	Domestic Multi-Family Service ESAP	DM-1 ESAP	-	-	-	- %	- %	- %	4
5	Total Residential - Non-TOU		13,176,381	13,176,381	-	- %	3.27 %	- %	5
6									6
7	Optional Domestic Service - TOU	OD-1 TOU	124,553	124,553	-	- %	3.56 %	- %	7
8	Optional Domestic Service - TOU ESAP	OD-1 TOU ESAP	-	-	-	- %	- %	- %	8
9	Optional Domestic Multi-Family Service - TOU	ODM-1 TOU	2,892	2,892	-	- %	4.07 %	- %	9
10	Optional Domestic Multi-Family Service - TOU ESAP	ODM-1 TOU ESAP	-	-	-	- %	- %	- %	10
11	Total Residential - TOU		127,445	127,445	-	- %	3.54 %	- %	11
12									12
13	**Total Residential**		**13,303,826**	**13,303,826**	**-**	**- %**	**3.28 %**	**- %**	13
14									14
15	Small General Service	GS-1	3,270,729	3,270,729	-	- %	3.77 %	- %	15
16	Small General Service ESAP	GS-1 ESAP	-	-	-	- %	- %	- %	16
17	Optional General Service - Time-of-Use	OGS-1 TOU	129,428	129,428	-	- %	3.93 %	- %	17
18	Optional General Service - Time-of-Use ESAP	OGS-1 TOU ESAP	-	-	-	- %	- %	- %	18
19	Small General Service - SSR	GS-1 SSR	105	105	-	- %	2.30 %	- %	19
20	Wireless Communication Service	WCS	413	413	-	- %	4.60 %	- %	20
21	Irrigation Service	IS-1	183,979	183,979	-	- %	3.27 %	- %	21
22	Interruptible Irrigation Service	IS-2	-	-	-	- %	- %	- %	22
23	City of Elko Water Pumping	WP	34,479	34,479	-	- %	3.94 %	- %	23
24	Total Small General Service		3,619,133	3,619,133	-	- %	3.46 %	- %	24
25									25
26	Medium General Service -Secondary	GS-2S	6,733,105	6,733,105	-	- %	4.18 %	- %	26
27	Medium General Service - Primary	GS-2P	253,156	253,156	-	- %	4.66 %	- %	27
28	Medium General Service - Transmission	GS-2T	81,286	81,286	-	- %	4.99 %	- %	28
29	Medium General Service - TOU - Secondary	GS-2S TOU	2,012,851	2,012,851	-	- %	4.19 %	- %	29
30	Medium General Service - TOU - Primary	GS-2P TOU	297,255	297,255	-	- %	4.61 %	- %	30
31	Medium General Service - TOU - Transmission	GS-2T TOU	61,487	61,487	-	- %	4.60 %	- %	31
32	Optional Medium General Service - TOU - Secondary	OGS-2S TOU	1,484,024	1,484,024	-	- %	4.14 %	- %	32
33	Optional Medium General Service - TOU - Primary	OGS-2P TOU	14,741	14,741	-	- %	4.71 %	- %	33
34	Optional Medium General Service - TOU - Transmission	OGS-2T TOU	-	-	-	- %	- %	- %	34
35	Medium General Service - Secondary - SSR	GS-2S SSR	-	-	-	- %	- %	- %	35
36	Medium General Service - Primary - SSR	GS-2P SSR	19	19	-	- %	0.10 %	- %	36
37	Medium General Service - Transmission - SSR	GS-2T SSR	5,186	5,186	-	- %	3.87 %	- %	37
38	Medium General Service - Secondary TOU - LSR	GS-2S TOU LSR	-	-	-	- %	- %	- %	38
39	Medium General Service - Primary TOU - LSR	GS-2P TOU LSR	-	-	-	- %	- %	- %	39
40	Medium General Service - Transmission TOU - LSR	GS-2T TOU LSR	12,053	12,053	-	- %	3.06 %	- %	40
41	Total Medium General Service		10,955,163	10,955,163	-	- %	4.20 %	- %	41
42									42
43	Large General Service - Secondary	GS-3S	1,731,438	1,731,438	-	- %	4.32 %	- %	43
44	Large General Service - Primary	GS-3P	2,220,524	2,220,524	-	- %	4.45 %	- %	44
45	Large General Service - Transmission	GS-3T	5,935,652	5,935,652	-	- %	5.10 %	- %	45
46	Large General Service - Secondary - LSR	GS-3S LSR	-	-	-	- %	- %	- %	46
47	Large General Service - Primary - LSR	GS-3P LSR	6,884	6,884	-	- %	4.11 %	- %	47
48	Large General Service - Transmission - LSR	GS-3T LSR	3,338,849	3,338,849	-	- %	5.09 %	- %	48
49	Total Large General Service		13,233,347	13,233,347	-	- %	4.86 %	- %	49
50									50
51	Large Transmission Service	GS-4	122,615	122,615	-	- %	4.94 %	- %	51
52									52
53	Street Lighting Service	SL	53,358	53,358	-	- %	1.13 %	- %	53
54	Outdoor Lighting Service	OLS	22,606	22,606	-	- %	1.38 %	- %	54
55	Total Lighting Service		75,964	75,964	-	- %	1.20 %	- %	55
56									56
57	**Total Non-Residential**		**28,006,222**	**28,006,222**	**-**	**- %**	**4.33 %**	**- %**	57
58									58
59	**Total - all classes**		**41,310,048**	**41,310,048**	**-**	**- %**	**3.92 %**	**- %**	59
60									60
61	Unbilled	Unbilled	(118,459)	(118,459)	-	- %	6.95 %	- %	61
62									62
63	**Total - all classes with Unbilled**		**41,191,589**	**41,191,589**	**-**	**- %**	**3.92 %**	**- %**	63
64									64
65	Distribution Only Service	DOS	-	-	-	- %	- %	- %	65
66									66
67	Unbilled - DOS	Unbilled - DOS	-	-	-	- %	- %	- %	67
68									68
69	Total Distribution Only Service		-	-	-	- %	- %	- %	69
70									70
71	**Total - All Classes With DOS**		**$ 41,191,589**	**$ 41,191,589**	**$ -**	**- %**	**3.89 %**	**- %**	71

TABLE 5
SIERRA PACIFIC POWER COMPANY
d/b/a NV Energy
PRESENT & PROPOSED RATE REVENUE: REPR
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

Ln No	(a) Rate Schedule Description		(b) REPR Revenue Present	(c) REPR Revenue Proposed	(d) Difference [(c)-(b)]	(e) Percent Change in Component [(d)/(b)]	(f) Percent Component Rev to Total Present Rev	(g) Percentage Change to Total Revenue [(e)*(f)]	Ln No
1	Domestic Service	D-1	$ 3,863,806	$ 1,942,818	$ (1,920,988)	(49.72)%	1.15 %	(0.57)%	1
2	Domestic Multi-Family Service	DM-1	800,633	402,577	(398,056)	(49.72)%	1.20 %	(0.60)%	2
3	Domestic Service ESAP	D-1 ESAP	10,503	5,281	(5,222)	(49.72)%	1.25 %	(0.62)%	3
4	Domestic Multi-Family Service ESAP	DM-1 ESAP	3,455	1,737	(1,718)	(49.73)%	1.32 %	(0.65)%	4
5	Total Residential - Non-TOU		4,678,397	2,352,413	(2,325,984)	(49.72)%	1.16 %	(0.58)%	5
6									6
7	Optional Domestic Service - TOU	OD-1 TOU	44,092	22,171	(21,921)	(49.72)%	1.26 %	(0.63)%	7
8	Optional Domestic Service - TOU ESAP	OD-1 TOU ESAP	460	231	(229)	(49.78)%	1.49 %	(0.74)%	8
9	Optional Domestic Multi-Family Service - TOU	ODM-1 TOU	1,024	515	(509)	(49.71)%	1.44 %	(0.72)%	9
10	Optional Domestic Multi-Family Service - TOU ESAP	ODM-1 TOU ESAP	47	24	(23)	(48.94)%	1.93 %	(0.94)%	10
11	Total Residential - TOU		45,623	22,941	(22,682)	(49.72)%	1.27 %	(0.63)%	11
12									12
13	**Total Residential**		**4,724,020**	**2,375,354**	**(2,348,666)**	**(49.72)%**	**1.16 %**	**(0.58)%**	13
14									14
15	Small General Service	GS-1	1,157,838	582,189	(575,649)	(49.72)%	1.33 %	(0.66)%	15
16	Small General Service ESAP	GS-1 ESAP	891	448	(443)	(49.72)%	1.50 %	(0.75)%	16
17	Optional General Service - Time-of-Use	OGS-1 TOU	45,818	23,038	(22,780)	(49.72)%	1.39 %	(0.69)%	17
18	Optional General Service - Time-of-Use ESAP	OGS-1 TOU ESAP	40	20	(20)	(50.00)%	1.82 %	(0.91)%	18
19	Small General Service - SSR	GS-1 SSR	37	19	(18)	(48.65)%	0.81 %	(0.39)%	19
20	Wireless Communication Service	WCS	146	73	(73)	(50.00)%	1.63 %	(0.81)%	20
21	Irrigation Service	IS-1	65,129	32,748	(32,381)	(49.72)%	1.16 %	(0.58)%	21
22	Interruptible Irrigation Service	IS-2	-	-	-	- %	- %	- %	22
23	City of Elko Water Pumping	WP	12,206	6,137	(6,069)	(49.72)%	1.40 %	(0.69)%	23
24	Total Small General Service		1,282,105	644,672	(637,433)	(49.72)%	1.23 %	(0.61)%	24
25									25
26	Medium General Service -Secondary	GS-2S	2,383,519	1,198,493	(1,185,026)	(49.72)%	1.48 %	(0.74)%	26
27	Medium General Service - Primary	GS-2P	89,617	45,062	(44,555)	(49.72)%	1.65 %	(0.82)%	27
28	Medium General Service - Transmission	GS-2T	28,775	14,469	(14,306)	(49.72)%	1.77 %	(0.88)%	28
29	Medium General Service - TOU - Secondary	GS-2S TOU	712,549	358,288	(354,261)	(49.72)%	1.48 %	(0.74)%	29
30	Medium General Service - TOU - Primary	GS-2P TOU	105,228	52,911	(52,317)	(49.72)%	1.63 %	(0.81)%	30
31	Medium General Service - TOU - Transmission	GS-2T TOU	21,767	10,945	(10,822)	(49.72)%	1.63 %	(0.81)%	31
32	Optional Medium General Service - TOU - Secondary	OGS-2S TOU	525,345	264,157	(261,188)	(49.72)%	1.46 %	(0.73)%	32
33	Optional Medium General Service - TOU - Primary	OGS-2P TOU	5,218	2,624	(2,594)	(49.71)%	1.67 %	(0.83)%	33
34	Optional Medium General Service - TOU - Transmission	OGS-2T TOU	-	-	-	- %	- %	- %	34
35	Medium General Service - Secondary - SSR	GS-2S SSR	-	-	-	- %	- %	- %	35
36	Medium General Service - Primary - SSR	GS-2P SSR	7	3	(4)	(57.14)%	0.04 %	(0.02)%	36
37	Medium General Service - Transmission - SSR	GS-2T SSR	1,836	923	(913)	(49.73)%	1.37 %	(0.68)%	37
38	Medium General Service - Secondary TOU - LSR	GS-2S TOU LSR	-	-	-	- %	- %	- %	38
39	Medium General Service - Primary TOU - LSR	GS-2P TOU LSR	-	-	-	- %	- %	- %	39
40	Medium General Service - Transmission TOU - LSR	GS-2T TOU LSR	4,267	2,145	(2,122)	(49.73)%	1.08 %	(0.54)%	40
41	Total Medium General Service		3,878,128	1,950,020	(1,928,108)	(49.72)%	1.49 %	(0.74)%	41
42									42
43	Large General Service - Secondary	GS-3S	612,929	308,196	(304,733)	(49.72)%	1.53 %	(0.76)%	43
44	Large General Service - Primary	GS-3P	786,065	395,253	(390,812)	(49.72)%	1.57 %	(0.78)%	44
45	Large General Service - Transmission	GS-3T	2,101,221	1,056,546	(1,044,675)	(49.72)%	1.80 %	(0.90)%	45
46	Large General Service - Secondary - LSR	GS-3S LSR	-	-	-	- %	- %	- %	46
47	Large General Service - Primary - LSR	GS-3P LSR	2,437	1,225	(1,212)	(49.73)%	1.46 %	(0.72)%	47
48	Large General Service - Transmission - LSR	GS-3T LSR	1,181,953	594,315	(587,638)	(49.72)%	1.80 %	(0.90)%	48
49	Total Large General Service		4,684,605	2,355,535	(2,329,070)	(49.72)%	1.72 %	(0.86)%	49
50									50
51	Large Transmission Service	GS-4	43,406	21,825	(21,581)	(49.72)%	1.75 %	(0.87)%	51
52									52
53	Street Lighting Service	SL	18,889	9,498	(9,391)	(49.72)%	0.40 %	(0.20)%	53
54	Outdoor Lighting Service	OLS	8,003	4,024	(3,979)	(49.72)%	0.49 %	(0.24)%	54
55	Total Lighting Service		26,892	13,522	(13,370)	(49.72)%	0.42 %	(0.21)%	55
56									56
57	**Total Non-Residential**		**9,915,136**	**4,985,574**	**(4,929,562)**	**(49.72)%**	**1.53 %**	**(0.76)%**	57
58									58
59	**Total - all classes**		**14,639,156**	**7,360,928**	**(7,278,228)**	**(49.72)%**	**1.39 %**	**(0.69)%**	59
60									60
61	Unbilled	Unbilled	(41,934)	(21,086)	20,848	(49.72)%	2.46 %	(1.22)%	61
62									62
63	**Total - all classes with Unbilled**		**14,597,222**	**7,339,842**	**(7,257,380)**	**(49.72)%**	**1.39 %**	**(0.69)%**	63
64									64
65	Distribution Only Service	DOS	-	-	-	- %	- %	- %	65
66									66
67	Unbilled - DOS	Unbilled - DOS	-	-	-	- %	- %	- %	67
68									68
69	Total Distribution Only Service		-	-	-	- %	- %	- %	69
70									70
71	**Total - All Classes With DOS**		**$ 14,597,222**	**$ 7,339,842**	**$ (7,257,380)**	**(49.72)%**	**1.38 %**	**(0.69)%**	71

TABLE 6
SIERRA PACIFIC POWER COMPANY
d/b/a NV Energy
PRESENT & PROPOSED RATE REVENUE: BASE ENERGY EFFICIENCY PROGRAM RATE (EEPR)
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

Ln No	(a) Rate Schedule Description		(b) Base EEPR Revenue Present	(c) Base EEPR Revenue Proposed	(d) Difference [(c)-(b)]	(e) Percent Change in Component [(d)/(b)]	(f) Percent Component Rev to Total Present Rev	(g) Percentage Change to Total Revenue [(e)*(f)]	Ln No
1	Domestic Service	D-1	$ 4,933,446	$ 5,042,592	$ 109,146	2.21 %	1.47 %	0.03 %	1
2	Domestic Multi-Family Service	DM-1	981,566	1,004,184	22,618	2.30 %	1.47 %	0.03 %	2
3	Domestic Service ESAP	D-1 ESAP	13,412	13,709	297	2.21 %	1.60 %	0.04 %	3
4	Domestic Multi-Family Service ESAP	DM-1 ESAP	4,235	4,333	98	2.31 %	1.61 %	0.04 %	4
5	Total Residential - Non-TOU		5,932,659	6,064,818	132,159	2.23 %	1.47 %	0.03 %	5
6									6
7	Optional Domestic Service - TOU	OD-1 TOU	56,297	57,543	1,246	2.21 %	1.61 %	0.04 %	7
8	Optional Domestic Service - TOU ESAP	OD-1 TOU ESAP	587	600	13	2.21 %	1.91 %	0.04 %	8
9	Optional Domestic Multi-Family Service - TOU	ODM-1 TOU	1,255	1,284	29	2.31 %	1.77 %	0.04 %	9
10	Optional Domestic Multi-Family Service - TOU ESAP	ODM-1 TOU ESAP	58	59	1	1.72 %	2.38 %	0.04 %	10
11	Total Residential - TOU		58,197	59,486	1,289	2.21 %	1.61 %	0.04 %	11
12									12
13	**Total Residential**		**5,990,856**	**6,124,304**	**133,448**	**2.23 %**	**1.48 %**	**0.03 %**	13
14									14
15	Small General Service	GS-1	1,046,633	1,072,800	26,167	2.50 %	1.21 %	0.03 %	15
16	Small General Service ESAP	GS-1 ESAP	805	825	20	2.48 %	1.35 %	0.03 %	16
17	Optional General Service - Time-of-Use	OGS-1 TOU	40,381	41,417	1,036	2.57 %	1.23 %	0.03 %	17
18	Optional General Service - Time-of-Use ESAP	OGS-1 TOU ESAP	35	36	1	2.86 %	1.59 %	0.05 %	18
19	Small General Service - SSR	GS-1 SSR	34	34	-	- %	0.74 %	- %	19
20	Wireless Communication Service	WCS	132	135	3	2.27 %	1.47 %	0.03 %	20
21	Irrigation Service	IS-1	89,782	93,094	3,312	3.69 %	1.60 %	0.06 %	21
22	Interruptible Irrigation Service	IS-2	-	-	-	- %	- %	- %	22
23	City of Elko Water Pumping	WP	12,412	12,757	345	2.78 %	1.42 %	0.04 %	23
24	Total Small General Service		1,190,214	1,221,098	30,884	2.59 %	1.14 %	0.03 %	24
25									25
26	Medium General Service -Secondary	GS-2S	2,168,060	2,221,925	53,865	2.48 %	1.34 %	0.03 %	26
27	Medium General Service - Primary	GS-2P	75,441	77,972	2,531	3.35 %	1.39 %	0.05 %	27
28	Medium General Service - Transmission	GS-2T	19,996	20,484	488	2.44 %	1.23 %	0.03 %	28
29	Medium General Service - TOU - Secondary	GS-2S TOU	696,446	716,575	20,129	2.89 %	1.45 %	0.04 %	29
30	Medium General Service - TOU - Primary	GS-2P TOU	98,094	101,067	2,973	3.03 %	1.52 %	0.05 %	30
31	Medium General Service - TOU - Transmission	GS-2T TOU	17,093	17,585	492	2.88 %	1.28 %	0.04 %	31
32	Optional Medium General Service - TOU - Secondary	OGS-2S TOU	483,792	495,664	11,872	2.45 %	1.35 %	0.03 %	32
33	Optional Medium General Service - TOU - Primary	OGS-2P TOU	4,393	4,540	147	3.35 %	1.40 %	0.05 %	33
34	Optional Medium General Service - TOU - Transmission	OGS-2T TOU	-	-	-	- %	- %	- %	34
35	Medium General Service - Secondary - SSR	GS-2S SSR	-	-	-	- %	- %	- %	35
36	Medium General Service - Primary - SSR	GS-2P SSR	6	6	-	- %	0.03 %	- %	36
37	Medium General Service - Transmission - SSR	GS-2T SSR	1,276	1,307	31	2.43 %	0.95 %	0.02 %	37
38	Medium General Service - Secondary TOU - LSR	GS-2S TOU LSR	-	-	-	- %	- %	- %	38
39	Medium General Service - Primary TOU - LSR	GS-2P TOU LSR	-	-	-	- %	- %	- %	39
40	Medium General Service - Transmission TOU - LSR	GS-2T TOU LSR	3,351	3,447	96	2.86 %	0.85 %	0.02 %	40
41	Total Medium General Service		3,567,948	3,660,572	92,624	2.60 %	1.37 %	0.04 %	41
42									42
43	Large General Service - Secondary	GS-3S	502,117	578,300	76,183	15.17 %	1.25 %	0.19 %	43
44	Large General Service - Primary	GS-3P	577,336	661,716	84,380	14.62 %	1.16 %	0.17 %	44
45	Large General Service - Transmission	GS-3T	1,650,111	1,448,299	(201,812)	(12.23)%	1.42 %	(0.17)%	45
46	Large General Service - Secondary - LSR	GS-3S LSR	-	-	-	- %	- %	- %	46
47	Large General Service - Primary - LSR	GS-3P LSR	1,790	2,051	261	14.58 %	1.07 %	0.16 %	47
48	Large General Service - Transmission - LSR	GS-3T LSR	928,200	814,679	(113,521)	(12.23)%	1.42 %	(0.17)%	48
49	Total Large General Service		3,659,554	3,505,045	(154,509)	(4.22)%	1.34 %	(0.06)%	49
50									50
51	Large Transmission Service	GS-4	36,539	38,011	1,472	4.03 %	1.47 %	0.06 %	51
52									52
53	Street Lighting Service	SL	13,446	13,980	534	3.97 %	0.29 %	0.01 %	53
54	Outdoor Lighting Service	OLS	6,330	6,510	180	2.84 %	0.39 %	0.01 %	54
55	Total Lighting Service		19,776	20,490	714	3.61 %	0.31 %	0.01 %	55
56									56
57	**Total Non-Residential**		**8,474,031**	**8,445,216**	**(28,815)**	**(0.34)%**	**1.31 %**	**(0.00)%**	57
58									58
59	**Total - all classes**		**14,464,887**	**14,569,520**	**104,633**	**0.72 %**	**1.37 %**	**0.01 %**	59
60									60
61	Unbilled	Unbilled	-	-	-	- %	- %	- %	61
62									62
63	**Total - all classes with Unbilled**		**14,464,887**	**14,569,520**	**104,633**	**0.72 %**	**1.38 %**	**0.01 %**	63
64									64
65	Distribution Only Service	DOS	-	-	-	- %	- %	- %	65
66									66
67	Unbilled - DOS	Unbilled - DOS	-	-	-	- %	- %	- %	67
68									68
69	Total Distribution Only Service		-	-	-	- %	- %	- %	69
70									70
71	**Total - All Classes With DOS**		**$ 14,464,887**	**$ 14,569,520**	**$ 104,633**	**0.72 %**	**1.37 %**	**0.01 %**	71

TABLE 7
SIERRA PACIFIC POWER COMPANY
d/b/a NV Energy
PRESENT & PROPOSED RATE REVENUE: AMORTIZATION ENERGY EFFICIENCY PROGRAM RATE (EEPR)
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

Ln No	(a) Rate Schedule Description		(b) Amort EEPR Revenue Present	(c) Amort EEPR Revenue Proposed	(d) Difference [(c)-(b)]	(e) Percent Change in Component [(d)/(b)]	(f) Percent Component Rev to Total Present Rev	(g) Percentage Change to Total Revenue [(e)*(f)]	Ln No
1	Domestic Service	D-1	$ (1,462,570)	$ (371,101)	$ 1,091,469	(74.63)%	(0.44)%	0.33 %	1
2	Domestic Multi-Family Service	DM-1	(303,064)	(76,897)	226,167	(74.63)%	(0.45)%	0.34 %	2
3	Domestic Service ESAP	D-1 ESAP	(3,976)	(1,009)	2,967	(74.62)%	(0.47)%	0.35 %	3
4	Domestic Multi-Family Service ESAP	DM-1 ESAP	(1,307)	(332)	975	(74.60)%	(0.50)%	0.37 %	4
5	Total Residential - Non-TOU		(1,770,917)	(449,339)	1,321,578	(74.63)%	(0.44)%	0.33 %	5
6									6
7	Optional Domestic Service - TOU	OD-1 TOU	(16,690)	(4,233)	12,457	(74.64)%	(0.48)%	0.36 %	7
8	Optional Domestic Service - TOU ESAP	OD-1 TOU ESAP	(174)	(43)	131	(75.29)%	(0.57)%	0.43 %	8
9	Optional Domestic Multi-Family Service - TOU	ODM-1 TOU	(388)	(99)	289	(74.48)%	(0.55)%	0.41 %	9
10	Optional Domestic Multi-Family Service - TOU ESAP	ODM-1 TOU ESAP	(18)	(5)	13	(72.22)%	(0.74)%	0.53 %	10
11	Total Residential - TOU		(17,270)	(4,380)	12,890	(74.64)%	(0.48)%	0.36 %	11
12									12
13	**Total Residential**		**(1,788,187)**	**(453,719)**	**1,334,468**	**(74.63)%**	**(0.44)%**	**0.33 %**	13
14									14
15	Small General Service	GS-1	(438,278)	(111,205)	327,073	(74.63)%	(0.50)%	0.38 %	15
16	Small General Service ESAP	GS-1 ESAP	(337)	(86)	251	(74.48)%	(0.57)%	0.42 %	16
17	Optional General Service - Time-of-Use	OGS-1 TOU	(17,344)	(4,401)	12,943	(74.63)%	(0.53)%	0.39 %	17
18	Optional General Service - Time-of-Use ESAP	OGS-1 TOU ESAP	(15)	(4)	11	(73.33)%	(0.68)%	0.50 %	18
19	Small General Service - SSR	GS-1 SSR	(14)	(4)	10	(71.43)%	(0.31)%	0.22 %	19
20	Wireless Communication Service	WCS	(55)	(14)	41	(74.55)%	(0.61)%	0.46 %	20
21	Irrigation Service	IS-1	(24,653)	(6,255)	18,398	(74.63)%	(0.44)%	0.33 %	21
22	Interruptible Irrigation Service	IS-2	-	-	-	- %	- %	- %	22
23	City of Elko Water Pumping	WP	(4,620)	(1,172)	3,448	(74.63)%	(0.53)%	0.39 %	23
24	Total Small General Service		(485,316)	(123,141)	362,175	(74.63)%	(0.46)%	0.35 %	24
25									25
26	Medium General Service -Secondary	GS-2S	(902,236)	(228,926)	673,310	(74.63)%	(0.56)%	0.42 %	26
27	Medium General Service - Primary	GS-2P	(33,923)	(8,607)	25,316	(74.63)%	(0.62)%	0.47 %	27
28	Medium General Service - Transmission	GS-2T	(10,892)	(2,764)	8,128	(74.62)%	(0.67)%	0.50 %	28
29	Medium General Service - TOU - Secondary	GS-2S TOU	(269,722)	(68,437)	201,285	(74.63)%	(0.56)%	0.42 %	29
30	Medium General Service - TOU - Primary	GS-2P TOU	(39,832)	(10,107)	29,725	(74.63)%	(0.62)%	0.46 %	30
31	Medium General Service - TOU - Transmission	GS-2T TOU	(8,239)	(2,091)	6,148	(74.62)%	(0.62)%	0.46 %	31
32	Optional Medium General Service - TOU - Secondary	OGS-2S TOU	(198,860)	(50,457)	148,403	(74.63)%	(0.55)%	0.41 %	32
33	Optional Medium General Service - TOU - Primary	OGS-2P TOU	(1,975)	(501)	1,474	(74.63)%	(0.63)%	0.47 %	33
34	Optional Medium General Service - TOU - Transmission	OGS-2T TOU	-	-	-	- %	- %	- %	34
35	Medium General Service - Secondary - SSR	GS-2S SSR	-	-	-	- %	- %	- %	35
36	Medium General Service - Primary - SSR	GS-2P SSR	(3)	(1)	2	(66.67)%	(0.02)%	0.01 %	36
37	Medium General Service - Transmission - SSR	GS-2T SSR	(695)	(176)	519	(74.68)%	(0.52)%	0.39 %	37
38	Medium General Service - Secondary TOU - LSR	GS-2S TOU LSR	-	-	-	- %	- %	- %	38
39	Medium General Service - Primary TOU - LSR	GS-2P TOU LSR	-	-	-	- %	- %	- %	39
40	Medium General Service - Transmission TOU - LSR	GS-2T TOU LSR	(1,615)	(410)	1,205	(74.61)%	(0.41)%	0.31 %	40
41	Total Medium General Service		(1,467,992)	(372,477)	1,095,515	(74.63)%	(0.56)%	0.42 %	41
42									42
43	Large General Service - Secondary	GS-3S	(232,013)	(58,869)	173,144	(74.63)%	(0.58)%	0.43 %	43
44	Large General Service - Primary	GS-3P	(297,550)	(75,498)	222,052	(74.63)%	(0.60)%	0.44 %	44
45	Large General Service - Transmission	GS-3T	(795,377)	(201,812)	593,565	(74.63)%	(0.68)%	0.51 %	45
46	Large General Service - Secondary - LSR	GS-3S LSR	-	-	-	- %	- %	- %	46
47	Large General Service - Primary - LSR	GS-3P LSR	(922)	(234)	688	(74.62)%	(0.55)%	0.41 %	47
48	Large General Service - Transmission - LSR	GS-3T LSR	(447,406)	(113,521)	333,885	(74.63)%	(0.68)%	0.51 %	48
49	Total Large General Service		(1,773,268)	(449,934)	1,323,334	(74.63)%	(0.65)%	0.49 %	49
50									50
51	Large Transmission Service	GS-4	(16,430)	(4,169)	12,261	(74.63)%	(0.66)%	0.49 %	51
52									52
53	Street Lighting Service	SL	(7,150)	(1,814)	5,336	(74.63)%	(0.15)%	0.11 %	53
54	Outdoor Lighting Service	OLS	(3,029)	(769)	2,260	(74.61)%	(0.18)%	0.14 %	54
55	Total Lighting Service		(10,179)	(2,583)	7,596	(74.62)%	(0.16)%	0.12 %	55
56									56
57	**Total Non-Residential**		**(3,753,185)**	**(952,304)**	**2,800,881**	**(74.63)%**	**(0.58)%**	**0.43 %**	57
58									58
59	**Total - all classes**		**(5,541,372)**	**(1,406,023)**	**4,135,349**	**(74.63)%**	**(0.53)%**	**0.39 %**	59
60									60
61	Unbilled	Unbilled	15,873	4,028	(11,845)	(74.62)%	(0.93)%	0.70 %	61
62									62
63	**Total - all classes with Unbilled**		**(5,525,499)**	**(1,401,995)**	**4,123,504**	**(74.63)%**	**(0.53)%**	**0.39 %**	63
64									64
65	Distribution Only Service	DOS	-	-	-	- %	- %	- %	65
66									66
67	Unbilled - DOS	Unbilled - DOS	-	-	-	- %	- %	- %	67
68									68
69	Total Distribution Only Service		-	-	-	- %	- %	- %	69
70									70
71	**Total - All Classes With DOS**		**$ (5,525,499)**	**$ (1,401,995)**	**$ 4,123,504**	**(74.63)%**	**(0.52)%**	**0.39 %**	71

TABLE 8
SIERRA PACIFIC POWER COMPANY
d/b/a NV Energy
PRESENT & PROPOSED RATE REVENUE: BASE ENERGY EFFICIENCY IMPLEMENTATION PROGRAM RATE (EEIR)
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	
			Base EEIR Revenue			Percent Change		Percentage Change	
Ln No	Rate Schedule Description		Present	Proposed	Difference [(c)-(b)]	in Component [(d)/(b)]	Percent Component Rev to Total Present Rev	to Total Revenue [(e)*(f)]	Ln No
1	Domestic Service	D-1	$ 414,759	$ 414,759	$ -	- %	0.12 %	- %	1
2	Domestic Multi-Family Service	DM-1	81,420	81,420	-	- %	0.12 %	- %	2
3	Domestic Service ESAP	D-1 ESAP	1,128	1,128	-	- %	0.13 %	- %	3
4	Domestic Multi-Family Service ESAP	DM-1 ESAP	351	351	-	- %	0.13 %	- %	4
5	Total Residential - Non-TOU		497,658	497,658	-	- %	0.12 %	- %	5
6									6
7	Optional Domestic Service - TOU	OD-1 TOU	4,732	4,732	-	- %	0.14 %	- %	7
8	Optional Domestic Service - TOU ESAP	OD-1 TOU ESAP	50	50	-	- %	0.16 %	- %	8
9	Optional Domestic Multi-Family Service - TOU	ODM-1 TOU	104	104	-	- %	0.15 %	- %	9
10	Optional Domestic Multi-Family Service - TOU ESAP	ODM-1 TOU ESAP	5	5	-	- %	0.21 %	- %	10
11	Total Residential - TOU		4,891	4,891	-	- %	0.14 %	- %	11
12									12
13	**Total Residential**		**502,549**	**502,549**	**-**	**- %**	**0.12 %**	**- %**	13
14									14
15	Small General Service	GS-1	85,038	91,580	6,542	7.69 %	0.10 %	0.01 %	15
16	Small General Service ESAP	GS-1 ESAP	65	70	5	7.69 %	0.11 %	0.01 %	16
17	Optional General Service - Time-of-Use	OGS-1 TOU	3,365	3,365	-	- %	0.10 %	- %	17
18	Optional General Service - Time-of-Use ESAP	OGS-1 TOU ESAP	3	3	-	- %	0.14 %	- %	18
19	Small General Service - SSR	GS-1 SSR	3	3	-	- %	0.07 %	- %	19
20	Wireless Communication Service	WCS	11	12	1	9.09 %	0.12 %	0.01 %	20
21	Irrigation Service	IS-1	7,359	7,727	368	5.00 %	0.13 %	0.01 %	21
22	Interruptible Irrigation Service	IS-2	-	-	-	- %	- %	- %	22
23	City of Elko Water Pumping	WP	1,034	1,034	-	- %	0.12 %	- %	23
24	Total Small General Service		96,878	103,794	6,916	7.14 %	0.09 %	0.01 %	24
25									25
26	Medium General Service -Secondary	GS-2S	175,061	188,527	13,466	7.69 %	0.11 %	0.01 %	26
27	Medium General Service - Primary	GS-2P	6,076	6,582	506	8.33 %	0.11 %	0.01 %	27
28	Medium General Service - Transmission	GS-2T	1,626	1,626	-	- %	0.10 %	- %	28
29	Medium General Service - TOU - Secondary	GS-2S TOU	56,359	60,385	4,026	7.14 %	0.12 %	0.01 %	29
30	Medium General Service - TOU - Primary	GS-2P TOU	8,323	8,323	-	- %	0.13 %	- %	30
31	Medium General Service - TOU - Transmission	GS-2T TOU	1,353	1,476	123	9.09 %	0.10 %	0.01 %	31
32	Optional Medium General Service - TOU - Secondary	OGS-2S TOU	38,585	41,553	2,968	7.69 %	0.11 %	0.01 %	32
33	Optional Medium General Service - TOU - Primary	OGS-2P TOU	354	383	29	8.19 %	0.11 %	0.01 %	33
34	Optional Medium General Service - TOU - Transmission	OGS-2T TOU	-	-	-	- %	- %	- %	34
35	Medium General Service - Secondary - SSR	GS-2S SSR	-	-	-	- %	- %	- %	35
36	Medium General Service - Primary - SSR	GS-2P SSR	-	1	1	- %	- %	- %	36
37	Medium General Service - Transmission - SSR	GS-2T SSR	104	104	-	- %	0.08 %	- %	37
38	Medium General Service - Secondary TOU - LSR	GS-2S TOU LSR	-	-	-	- %	- %	- %	38
39	Medium General Service - Primary TOU - LSR	GS-2P TOU LSR	-	-	-	- %	- %	- %	39
40	Medium General Service - Transmission TOU - LSR	GS-2T TOU LSR	265	289	24	9.06 %	0.07 %	0.01 %	40
41	Total Medium General Service		288,106	309,249	21,143	7.34 %	0.11 %	0.01 %	41
42									42
43	Large General Service - Secondary	GS-3S	41,554	48,480	6,926	16.67 %	0.10 %	0.02 %	43
44	Large General Service - Primary	GS-3P	48,852	53,293	4,441	9.09 %	0.10 %	0.01 %	44
45	Large General Service - Transmission	GS-3T	130,584	118,713	(11,871)	(9.09)%	0.11 %	(0.01)%	45
46	Large General Service - Secondary - LSR	GS-3S LSR	-	-	-	- %	- %	- %	46
47	Large General Service - Primary - LSR	GS-3P LSR	151	165	14	9.27 %	0.09 %	0.01 %	47
48	Large General Service - Transmission - LSR	GS-3T LSR	73,455	66,777	(6,678)	(9.09)%	0.11 %	(0.01)%	48
49	Total Large General Service		294,596	287,428	(7,168)	(2.43)%	0.11 %	(0.00)%	49
50									50
51	Large Transmission Service	GS-4	2,943	3,188	245	8.32 %	0.12 %	0.01 %	51
52									52
53	Street Lighting Service	SL	1,067	1,174	107	10.03 %	0.02 %	0.00 %	53
54	Outdoor Lighting Service	OLS	542	542	-	- %	0.03 %	- %	54
55	Total Lighting Service		1,609	1,716	107	6.65 %	0.03 %	0.00 %	55
56									56
57	**Total Non-Residential**		**684,132**	**705,375**	**21,243**	**3.11 %**	**0.11 %**	**0.00 %**	57
58									58
59	**Total - all classes**		**1,186,681**	**1,207,924**	**21,243**	**1.79 %**	**0.11 %**	**0.00 %**	59
60									60
61	Unbilled	Unbilled	-	-	-	- %	- %	- %	61
62									62
63	**Total - all classes with Unbilled**		**1,186,681**	**1,207,924**	**21,243**	**1.79 %**	**0.11 %**	**0.00 %**	63
64									64
65	Distribution Only Service	DOS	-	-	-	- %	- %	- %	65
66									66
67	Unbilled - DOS	Unbilled - DOS	-	-	-	- %	- %	- %	67
68									68
69	Total Distribution Only Service		-	-	-	- %	- %	- %	69
70									70
71	**Total - All Classes With DOS**		**$ 1,186,681**	**$ 1,207,924**	**$ 21,243**	**1.79 %**	**0.11 %**	**0.00 %**	71

TABLE 9
SIERRA PACIFIC POWER COMPANY
d/b/a NV Energy
PRESENT & PROPOSED RATE REVENUE: AMORTIZATION ENERGY EFFICIENCY IMPLEMENTATION PROGRAM RATE (EEIR)
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	
			Amort EEIR Revenue			Percent Change		Percentage Change	
Ln No	Rate Schedule Description		Present	Proposed	Difference [(c)-(b)]	in Component [(d)/(b)]	Percent Component Rev to Total Present Rev	to Total Revenue [(e)*(f)]	Ln No
1	Domestic Service	D-1	$ (130,976)	$ -	$ 130,976	(100.00)%	(0.04)%	0.04 %	1
2	Domestic Multi-Family Service	DM-1	(27,141)	-	27,141	(100.00)%	(0.04)%	0.04 %	2
3	Domestic Service ESAP	D-1 ESAP	(356)	-	356	(100.00)%	(0.04)%	0.04 %	3
4	Domestic Multi-Family Service ESAP	DM-1 ESAP	(117)	-	117	(100.00)%	(0.04)%	0.04 %	4
5	Total Residential - Non-TOU		(158,590)	-	158,590	(100.00)%	(0.04)%	0.04 %	5
6									6
7	Optional Domestic Service - TOU	OD-1 TOU	(1,493)	-	1,493	(100.00)%	(0.04)%	0.04 %	7
8	Optional Domestic Service - TOU ESAP	OD-1 TOU ESAP	(15)	-	15	(100.00)%	(0.05)%	0.05 %	8
9	Optional Domestic Multi-Family Service - TOU	ODM-1 TOU	(35)	-	35	(100.00)%	(0.05)%	0.05 %	9
10	Optional Domestic Multi-Family Service - TOU ESAP	ODM-1 TOU ESAP	(2)	-	2	(100.00)%	(0.08)%	0.08 %	10
11	Total Residential - TOU		(1,545)	-	1,545	(100.00)%	(0.04)%	0.04 %	11
12									12
13	**Total Residential**		**(160,135)**	**-**	**160,135**	**(100.00)%**	**(0.04)%**	**0.04 %**	13
14									14
15	Small General Service	GS-1	(39,248)	-	39,248	(100.00)%	(0.05)%	0.05 %	15
16	Small General Service ESAP	GS-1 ESAP	(30)	-	30	(100.00)%	(0.05)%	0.05 %	16
17	Optional General Service - Time-of-Use	OGS-1 TOU	(1,553)	-	1,553	(100.00)%	(0.05)%	0.05 %	17
18	Optional General Service - Time-of-Use ESAP	OGS-1 TOU ESAP	(1)	-	1	(100.00)%	(0.05)%	0.05 %	18
19	Small General Service - SSR	GS-1 SSR	(1)	-	1	(100.00)%	(0.02)%	0.02 %	19
20	Wireless Communication Service	WCS	(5)	-	5	(100.00)%	(0.06)%	0.06 %	20
21	Irrigation Service	IS-1	(2,208)	-	2,208	(100.00)%	(0.04)%	0.04 %	21
22	Interruptible Irrigation Service	IS-2	-	-	-	- %	- %	- %	22
23	City of Elko Water Pumping	WP	(414)	-	414	(100.00)%	(0.05)%	0.05 %	23
24	Total Small General Service		(43,460)	-	43,460	(100.00)%	(0.04)%	0.04 %	24
25									25
26	Medium General Service -Secondary	GS-2S	(80,797)	-	80,797	(100.00)%	(0.05)%	0.05 %	26
27	Medium General Service - Primary	GS-2P	(3,038)	-	3,038	(100.00)%	(0.06)%	0.06 %	27
28	Medium General Service - Transmission	GS-2T	(975)	-	975	(100.00)%	(0.06)%	0.06 %	28
29	Medium General Service - TOU - Secondary	GS-2S TOU	(24,154)	-	24,154	(100.00)%	(0.05)%	0.05 %	29
30	Medium General Service - TOU - Primary	GS-2P TOU	(3,567)	-	3,567	(100.00)%	(0.06)%	0.06 %	30
31	Medium General Service - TOU - Transmission	GS-2T TOU	(738)	-	738	(100.00)%	(0.06)%	0.06 %	31
32	Optional Medium General Service - TOU - Secondary	OGS-2S TOU	(17,808)	-	17,808	(100.00)%	(0.05)%	0.05 %	32
33	Optional Medium General Service - TOU - Primary	OGS-2P TOU	(177)	-	177	(100.00)%	(0.06)%	0.06 %	33
34	Optional Medium General Service - TOU - Transmission	OGS-2T TOU	-	-	-	- %	- %	- %	34
35	Medium General Service - Secondary - SSR	GS-2S SSR	-	-	-	- %	- %	- %	35
36	Medium General Service - Primary - SSR	GS-2P SSR	-	-	-	- %	- %	- %	36
37	Medium General Service - Transmission - SSR	GS-2T SSR	(62)	-	62	(100.00)%	(0.05)%	0.05 %	37
38	Medium General Service - Secondary TOU - LSR	GS-2S TOU LSR	-	-	-	- %	- %	- %	38
39	Medium General Service - Primary TOU - LSR	GS-2P TOU LSR	-	-	-	- %	- %	- %	39
40	Medium General Service - Transmission TOU - LSR	GS-2T TOU LSR	(145)	-	145	(100.00)%	(0.04)%	0.04 %	40
41	Total Medium General Service		(131,461)	-	131,461	(100.00)%	(0.05)%	0.05 %	41
42									42
43	Large General Service - Secondary	GS-3S	(20,778)	-	20,778	(100.00)%	(0.05)%	0.05 %	43
44	Large General Service - Primary	GS-3P	(26,646)	-	26,646	(100.00)%	(0.05)%	0.05 %	44
45	Large General Service - Transmission	GS-3T	(71,228)	-	71,228	(100.00)%	(0.06)%	0.06 %	45
46	Large General Service - Secondary - LSR	GS-3S LSR	-	-	-	- %	- %	- %	46
47	Large General Service - Primary - LSR	GS-3P LSR	(83)	-	83	(100.00)%	(0.05)%	0.05 %	47
48	Large General Service - Transmission - LSR	GS-3T LSR	(40,066)	-	40,066	(100.00)%	(0.06)%	0.06 %	48
49	Total Large General Service		(158,801)	-	158,801	(100.00)%	(0.06)%	0.06 %	49
50									50
51	Large Transmission Service	GS-4	(1,471)	-	1,471	(100.00)%	(0.06)%	0.06 %	51
52									52
53	Street Lighting Service	SL	(640)	-	640	(100.00)%	(0.01)%	0.01 %	53
54	Outdoor Lighting Service	OLS	(271)	-	271	(100.00)%	(0.02)%	0.02 %	54
55	Total Lighting Service		(911)	-	911	(100.00)%	(0.01)%	0.01 %	55
56									56
57	**Total Non-Residential**		**(336,104)**	**-**	**336,104**	**(100.00)%**	**(0.05)%**	**0.05 %**	57
58									58
59	**Total - all classes**		**(496,239)**	**-**	**496,239**	**(100.00)%**	**(0.05)%**	**0.05 %**	59
60									60
61	Unbilled	Unbilled	1,422	-	(1,422)	(100.00)%	(0.08)%	0.08 %	61
62									62
63	**Total - all classes with Unbilled**		**(494,817)**	**-**	**494,817**	**(100.00)%**	**(0.05)%**	**0.05 %**	63
64									64
65	Distribution Only Service	DOS	-	-	-	- %	- %	- %	65
66									66
67	Unbilled - DOS	Unbilled - DOS	-	-	-	- %	- %	- %	67
68									68
69	Total Distribution Only Service		-	-	-	- %	- %	- %	69
70									70
71	**Total - All Classes With DOS**		**$ (494,817)**	**$ -**	**$ 494,817**	**(100.00)%**	**(0.05)%**	**0.05 %**	71

TABLE 10
SIERRA PACIFIC POWER COMPANY
d/b/a NV Energy
PRESENT & PROPOSED RATE REVENUE: EEIR ADJUSTMENT REVENUE
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

Ln No	(a) Rate Schedule Description		(b) EEIR Adjustment Revenue Present	(c) EEIR Adjustment Revenue Proposed	(d) Difference [(c)-(b)]	(e) Percent Change in Component [(d)/(b)]	(f) Percent Component Rev to Total Present Rev	(g) Percentage Change to Total Revenue [(e)*(f)]	Ln No
1	Domestic Service	D-1	$ -	$ -	$ -	- %	- %	- %	1
2	Domestic Multi-Family Service	DM-1	-	-	-	- %	- %	- %	2
3	Domestic Service ESAP	D-1 ESAP	-	-	-	- %	- %	- %	3
4	Domestic Multi-Family Service ESAP	DM-1 ESAP	-	-	-	- %	- %	- %	4
5	Total Residential - Non-TOU		-	-	-	- %	- %	- %	5
6									6
7	Optional Domestic Service - TOU	OD-1 TOU	-	-	-	- %	- %	- %	7
8	Optional Domestic Service - TOU ESAP	OD-1 TOU ESAP	-	-	-	- %	- %	- %	8
9	Optional Domestic Multi-Family Service - TOU	ODM-1 TOU	-	-	-	- %	- %	- %	9
10	Optional Domestic Multi-Family Service - TOU ESAP	ODM-1 TOU ESAP	-	-	-	- %	- %	- %	10
11	Total Residential - TOU		-	-	-	- %	- %	- %	11
12									12
13	**Total Residential**		**-**	**-**	**-**	**- %**	**- %**	**- %**	13
14									14
15	Small General Service	GS-1	-	-	-	- %	- %	- %	15
16	Small General Service ESAP	GS-1 ESAP	-	-	-	- %	- %	- %	16
17	Optional General Service - Time-of-Use	OGS-1 TOU	-	-	-	- %	- %	- %	17
18	Optional General Service - Time-of-Use ESAP	OGS-1 TOU ESAP	-	-	-	- %	- %	- %	18
19	Small General Service - SSR	GS-1 SSR	-	-	-	- %	- %	- %	19
20	Wireless Communication Service	WCS	-	-	-	- %	- %	- %	20
21	Irrigation Service	IS-1	-	-	-	- %	- %	- %	21
22	Interruptible Irrigation Service	IS-2	-	-	-	- %	- %	- %	22
23	City of Elko Water Pumping	WP	-	-	-	- %	- %	- %	23
24	Total Small General Service		-	-	-	- %	- %	- %	24
25									25
26	Medium General Service -Secondary	GS-2S	-	-	-	- %	- %	- %	26
27	Medium General Service - Primary	GS-2P	-	-	-	- %	- %	- %	27
28	Medium General Service - Transmission	GS-2T	-	-	-	- %	- %	- %	28
29	Medium General Service - TOU - Secondary	GS-2S TOU	-	-	-	- %	- %	- %	29
30	Medium General Service - TOU - Primary	GS-2P TOU	-	-	-	- %	- %	- %	30
31	Medium General Service - TOU - Transmission	GS-2T TOU	-	-	-	- %	- %	- %	31
32	Optional Medium General Service - TOU - Secondary	OGS-2S TOU	-	-	-	- %	- %	- %	32
33	Optional Medium General Service - TOU - Primary	OGS-2P TOU	-	-	-	- %	- %	- %	33
34	Optional Medium General Service - TOU - Transmission	OGS-2T TOU	-	-	-	- %	- %	- %	34
35	Medium General Service - Secondary - SSR	GS-2S SSR	-	-	-	- %	- %	- %	35
36	Medium General Service - Primary - SSR	GS-2P SSR	-	-	-	- %	- %	- %	36
37	Medium General Service - Transmission - SSR	GS-2T SSR	-	-	-	- %	- %	- %	37
38	Medium General Service - Secondary TOU - LSR	GS-2S TOU LSR	-	-	-	- %	- %	- %	38
39	Medium General Service - Primary TOU - LSR	GS-2P TOU LSR	-	-	-	- %	- %	- %	39
40	Medium General Service - Transmission TOU - LSR	GS-2T TOU LSR	-	-	-	- %	- %	- %	40
41	Total Medium General Service		-	-	-	- %	- %	- %	41
42									42
43	Large General Service - Secondary	GS-3S	-	-	-	- %	- %	- %	43
44	Large General Service - Primary	GS-3P	-	-	-	- %	- %	- %	44
45	Large General Service - Transmission	GS-3T	-	-	-	- %	- %	- %	45
46	Large General Service - Secondary - LSR	GS-3S LSR	-	-	-	- %	- %	- %	46
47	Large General Service - Primary - LSR	GS-3P LSR	-	-	-	- %	- %	- %	47
48	Large General Service - Transmission - LSR	GS-3T LSR	-	-	-	- %	- %	- %	48
49	Total Large General Service		-	-	-	- %	- %	- %	49
50									50
51	Large Transmission Service	GS-4	-	-	-	- %	- %	- %	51
52									52
53	Street Lighting Service	SL	-	-	-	- %	- %	- %	53
54	Outdoor Lighting Service	OLS	-	-	-	- %	- %	- %	54
55	Total Lighting Service		-	-	-	- %	- %	- %	55
56									56
57	**Total Non-Residential**		**-**	**-**	**-**	**- %**	**- %**	**- %**	57
58									58
59	**Total - all classes**		**-**	**-**	**-**	**- %**	**- %**	**- %**	59
60									60
61	Unbilled	Unbilled	-	-	-	- %	- %	- %	61
62									62
63	**Total - all classes with Unbilled**		**-**	**-**	**-**	**- %**	**- %**	**- %**	63
64									64
65	Distribution Only Service	DOS	-	-	-	- %	- %	- %	65
66									66
67	Unbilled - DOS	Unbilled - DOS	-	-	-	- %	- %	- %	67
68									68
69	Total Distribution Only Service		-	-	-	- %	- %	- %	69
70									70
71	**Total - All Classes With DOS**		**$ -**	**$ -**	**$ -**	**- %**	**- %**	**- %**	71

TABLE 11
SIERRA PACIFIC POWER COMPANY
d/b/a NV Energy
PRESENT & PROPOSED RATE REVENUE: NDPP REVENUE
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	
			NDPP Revenue			Percent Change		Percentage Change	
Ln No	Rate Schedule Description		Present	Proposed	Difference [(c)-(b)]	in Component [(d)/(b)]	Percent Component Rev to Total Present Rev	to Total Revenue [(e)*(f)]	Ln No
1	Domestic Service	D-1	$ 1,615,377	$ 1,615,377	$ -	- %	0.48 %	- %	1
2	Domestic Multi-Family Service	DM-1	334,729	334,729	-	- %	0.50 %	- %	2
3	Domestic Service ESAP	D-1 ESAP	4,391	4,391	-	- %	0.52 %	- %	3
4	Domestic Multi-Family Service ESAP	DM-1 ESAP	1,444	1,444	-	- %	0.55 %	- %	4
5	Total Residential - Non-TOU		1,955,941	1,955,941	-	- %	0.49 %	- %	5
6									6
7	Optional Domestic Service - TOU	OD-1 TOU	18,433	18,433	-	- %	0.53 %	- %	7
8	Optional Domestic Service - TOU ESAP	OD-1 TOU ESAP	191	191	-	- %	0.62 %	- %	8
9	Optional Domestic Multi-Family Service - TOU	ODM-1 TOU	428	428	-	- %	0.60 %	- %	9
10	Optional Domestic Multi-Family Service - TOU ESAP	ODM-1 TOU ESAP	20	20	-	- %	0.82 %	- %	10
11	Total Residential - TOU		19,072	19,072	-	- %	0.53 %	- %	11
12									12
13	**Total Residential**		**1,975,013**	**1,975,013**	**-**	**- %**	**0.49 %**	**- %**	13
14									14
15	Small General Service	GS-1	484,067	484,067	-	- %	0.56 %	- %	15
16	Small General Service ESAP	GS-1 ESAP	372	372	-	- %	0.63 %	- %	16
17	Optional General Service - Time-of-Use	OGS-1 TOU	19,155	19,155	-	- %	0.58 %	- %	17
18	Optional General Service - Time-of-Use ESAP	OGS-1 TOU ESAP	17	17	-	- %	0.77 %	- %	18
19	Small General Service - SSR	GS-1 SSR	16	16	-	- %	0.35 %	- %	19
20	Wireless Communication Service	WCS	61	61	-	- %	0.68 %	- %	20
21	Irrigation Service	IS-1	27,229	27,229	-	- %	0.48 %	- %	21
22	Interruptible Irrigation Service	IS-2	74,412	74,412	-	- %	0.94 %	- %	22
23	City of Elko Water Pumping	WP	5,103	5,103	-	- %	0.58 %	- %	23
24	Total Small General Service		610,432	610,432	-	- %	0.58 %	- %	24
25									25
26	Medium General Service -Secondary	GS-2S	996,500	996,500	-	- %	0.62 %	- %	26
27	Medium General Service - Primary	GS-2P	37,467	37,467	-	- %	0.69 %	- %	27
28	Medium General Service - Transmission	GS-2T	12,030	12,030	-	- %	0.74 %	- %	28
29	Medium General Service - TOU - Secondary	GS-2S TOU	297,902	297,902	-	- %	0.62 %	- %	29
30	Medium General Service - TOU - Primary	GS-2P TOU	43,994	43,994	-	- %	0.68 %	- %	30
31	Medium General Service - TOU - Transmission	GS-2T TOU	9,100	9,100	-	- %	0.68 %	- %	31
32	Optional Medium General Service - TOU - Secondary	OGS-2S TOU	219,636	219,636	-	- %	0.61 %	- %	32
33	Optional Medium General Service - TOU - Primary	OGS-2P TOU	2,182	2,182	-	- %	0.70 %	- %	33
34	Optional Medium General Service - TOU - Transmission	OGS-2T TOU	-	-	-	- %	- %	- %	34
35	Medium General Service - Secondary - SSR	GS-2S SSR	-	-	-	- %	- %	- %	35
36	Medium General Service - Primary - SSR	GS-2P SSR	3	3	-	- %	0.02 %	- %	36
37	Medium General Service - Transmission - SSR	GS-2T SSR	768	768	-	- %	0.57 %	- %	37
38	Medium General Service - Secondary TOU - LSR	GS-2S TOU LSR	-	-	-	- %	- %	- %	38
39	Medium General Service - Primary TOU - LSR	GS-2P TOU LSR	-	-	-	- %	- %	- %	39
40	Medium General Service - Transmission TOU - LSR	GS-2T TOU LSR	1,784	1,784	-	- %	0.45 %	- %	40
41	Total Medium General Service		1,621,366	1,621,366	-	- %	0.62 %	- %	41
42									42
43	Large General Service - Secondary	GS-3S	256,253	256,253	-	- %	0.64 %	- %	43
44	Large General Service - Primary	GS-3P	328,637	328,637	-	- %	0.66 %	- %	44
45	Large General Service - Transmission	GS-3T	878,476	878,476	-	- %	0.75 %	- %	45
46	Large General Service - Secondary - LSR	GS-3S LSR	-	-	-	- %	- %	- %	46
47	Large General Service - Primary - LSR	GS-3P LSR	1,019	1,019	-	- %	0.61 %	- %	47
48	Large General Service - Transmission - LSR	GS-3T LSR	494,150	494,150	-	- %	0.75 %	- %	48
49	Total Large General Service		1,958,535	1,958,535	-	- %	0.72 %	- %	49
50									50
51	Large Transmission Service	GS-4	18,147	18,147	-	- %	0.73 %	- %	51
52									52
53	Street Lighting Service	SL	7,897	7,897	-	- %	0.17 %	- %	53
54	Outdoor Lighting Service	OLS	3,346	3,346	-	- %	0.20 %	- %	54
55	Total Lighting Service		11,243	11,243	-	- %	0.18 %	- %	55
56									56
57	**Total Non-Residential**		**4,219,723**	**4,219,723**	**-**	**- %**	**0.65 %**	**- %**	57
58									58
59	**Total - all classes**		**6,194,736**	**6,194,736**	**-**	**- %**	**0.59 %**	**- %**	59
60									60
61	Unbilled	Unbilled	(17,532)	(17,532)	-	- %	1.03 %	- %	61
62									62
63	**Total - all classes with Unbilled**		**6,177,204**	**6,177,204**	**-**	**- %**	**0.59 %**	**- %**	63
64									64
65	Distribution Only Service	DOS	2,077,222	2,077,222	-	- %	29.66 %	- %	65
66									66
67	Unbilled - DOS	Unbilled - DOS	16,367	16,367	-	- %	97.37 %	- %	67
68									68
69	Total Distribution Only Service		2,093,589	2,093,589	-	- %	29.82 %	- %	69
70									70
71	**Total - All Classes With DOS**		**$ 8,270,793**	**$ 8,270,793**	**$ -**	**- %**	**0.78 %**	**- %**	71

TABLE 12
SIERRA PACIFIC POWER COMPANY
d/b/a NV Energy
PRESENT & PROPOSED RATE REVENUE: TRED
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

Ln No	(a) Rate Schedule Description		(b) TRED Revenue Present	(c) TRED Revenue Proposed	(d) Difference [(c)-(b)]	(e) Percent Change in Component [(d)/(b)]	(f) Percent Component Rev to Total Present Rev	(g) Percentage Change to Total Revenue [(e)*(f)]	Ln No
1	Domestic Service	D-1	$ 1,571,719	$ 698,540	$ (873,179)	(55.56)%	0.47 %	(0.26)%	1
2	Domestic Multi-Family Service	DM-1	325,681	144,747	(180,934)	(55.56)%	0.49 %	(0.27)%	2
3	Domestic Service ESAP	D-1 ESAP	4,272	1,898	(2,374)	(55.57)%	0.51 %	(0.28)%	3
4	Domestic Multi-Family Service ESAP	DM-1 ESAP	1,405	625	(780)	(55.52)%	0.54 %	(0.30)%	4
5	Total Residential - Non-TOU		1,903,077	845,810	(1,057,267)	(55.56)%	0.47 %	(0.26)%	5
6									6
7	Optional Domestic Service - TOU	OD-1 TOU	17,933	7,972	(9,961)	(55.55)%	0.51 %	(0.28)%	7
8	Optional Domestic Service - TOU ESAP	OD-1 TOU ESAP	187	84	(103)	(55.08)%	0.61 %	(0.33)%	8
9	Optional Domestic Multi-Family Service - TOU	ODM-1 TOU	417	185	(232)	(55.64)%	0.59 %	(0.33)%	9
10	Optional Domestic Multi-Family Service - TOU ESAP	ODM-1 TOU ESAP	19	9	(10)	(52.63)%	0.78 %	(0.41)%	10
11	Total Residential - TOU		18,556	8,250	(10,306)	(55.54)%	0.51 %	(0.29)%	11
12									12
13	**Total Residential**		**1,921,633**	**854,060**	**(1,067,573)**	**(55.56)%**	**0.47 %**	**(0.26)%**	13
14									14
15	Small General Service	GS-1	470,984	209,327	(261,657)	(55.56)%	0.54 %	(0.30)%	15
16	Small General Service ESAP	GS-1 ESAP	362	161	(201)	(55.52)%	0.61 %	(0.34)%	16
17	Optional General Service - Time-of-Use	OGS-1 TOU	18,638	8,284	(10,354)	(55.55)%	0.57 %	(0.31)%	17
18	Optional General Service - Time-of-Use ESAP	OGS-1 TOU ESAP	16	7	(9)	(56.25)%	0.73 %	(0.41)%	18
19	Small General Service - SSR	GS-1 SSR	15	7	(8)	(53.33)%	0.33 %	(0.18)%	19
20	Wireless Communication Service	WCS	59	26	(33)	(55.93)%	0.66 %	(0.37)%	20
21	Irrigation Service	IS-1	26,493	11,775	(14,718)	(55.55)%	0.47 %	(0.26)%	21
22	Interruptible Irrigation Service	IS-2	-	-	-	- %	- %	- %	22
23	City of Elko Water Pumping	WP	4,965	2,207	(2,758)	(55.55)%	0.57 %	(0.32)%	23
24	Total Small General Service		521,532	231,794	(289,738)	(55.56)%	0.50 %	(0.28)%	24
25									25
26	Medium General Service -Secondary	GS-2S	969,567	430,919	(538,648)	(55.56)%	0.60 %	(0.33)%	26
27	Medium General Service - Primary	GS-2P	36,455	16,202	(20,253)	(55.56)%	0.67 %	(0.37)%	27
28	Medium General Service - Transmission	GS-2T	11,705	5,202	(6,503)	(55.56)%	0.72 %	(0.40)%	28
29	Medium General Service - TOU - Secondary	GS-2S TOU	289,851	128,822	(161,029)	(55.56)%	0.60 %	(0.33)%	29
30	Medium General Service - TOU - Primary	GS-2P TOU	42,805	19,024	(23,781)	(55.56)%	0.66 %	(0.37)%	30
31	Medium General Service - TOU - Transmission	GS-2T TOU	8,854	3,935	(4,919)	(55.56)%	0.66 %	(0.37)%	31
32	Optional Medium General Service - TOU - Secondary	OGS-2S TOU	213,699	94,978	(118,721)	(55.56)%	0.60 %	(0.33)%	32
33	Optional Medium General Service - TOU - Primary	OGS-2P TOU	2,123	943	(1,180)	(55.58)%	0.68 %	(0.38)%	33
34	Optional Medium General Service - TOU - Transmission	OGS-2T TOU	-	-	-	- %	- %	- %	34
35	Medium General Service - Secondary - SSR	GS-2S SSR	-	-	-	- %	- %	- %	35
36	Medium General Service - Primary - SSR	GS-2P SSR	3	1	(2)	(66.67)%	0.02 %	(0.01)%	36
37	Medium General Service - Transmission - SSR	GS-2T SSR	747	332	(415)	(55.56)%	0.56 %	(0.31)%	37
38	Medium General Service - Secondary TOU - LSR	GS-2S TOU LSR	-	-	-	- %	- %	- %	38
39	Medium General Service - Primary TOU - LSR	GS-2P TOU LSR	-	-	-	- %	- %	- %	39
40	Medium General Service - Transmission TOU - LSR	GS-2T TOU LSR	1,736	771	(965)	(55.59)%	0.44 %	(0.25)%	40
41	Total Medium General Service		1,577,545	701,129	(876,416)	(55.56)%	0.60 %	(0.34)%	41
42									42
43	Large General Service - Secondary	GS-3S	249,327	110,812	(138,515)	(55.56)%	0.62 %	(0.35)%	43
44	Large General Service - Primary	GS-3P	319,755	142,114	(177,641)	(55.56)%	0.64 %	(0.36)%	44
45	Large General Service - Transmission	GS-3T	854,734	379,882	(474,852)	(55.56)%	0.73 %	(0.41)%	45
46	Large General Service - Secondary - LSR	GS-3S LSR	-	-	-	- %	- %	- %	46
47	Large General Service - Primary - LSR	GS-3P LSR	991	441	(550)	(55.50)%	0.59 %	(0.33)%	47
48	Large General Service - Transmission - LSR	GS-3T LSR	480,794	213,686	(267,108)	(55.56)%	0.73 %	(0.41)%	48
49	Total Large General Service		1,905,601	846,935	(1,058,666)	(55.56)%	0.70 %	(0.39)%	49
50									50
51	Large Transmission Service	GS-4	17,657	7,847	(9,810)	(55.56)%	0.71 %	(0.40)%	51
52									52
53	Street Lighting Service	SL	7,684	3,415	(4,269)	(55.56)%	0.16 %	(0.09)%	53
54	Outdoor Lighting Service	OLS	3,256	1,447	(1,809)	(55.56)%	0.20 %	(0.11)%	54
55	Total Lighting Service		10,940	4,862	(6,078)	(55.56)%	0.17 %	(0.10)%	55
56									56
57	**Total Non-Residential**		**4,033,275**	**1,792,567**	**(2,240,708)**	**(55.56)%**	**0.62 %**	**(0.35)%**	57
58									58
59	**Total - all classes**		**5,954,908**	**2,646,627**	**(3,308,281)**	**(55.56)%**	**0.57 %**	**(0.31)%**	59
60									60
61	Unbilled	Unbilled	(17,058)	(7,581)	9,477	(55.56)%	1.00 %	(0.56)%	61
62									62
63	**Total - all classes with Unbilled**		**5,937,850**	**2,639,046**	**(3,298,804)**	**(55.56)%**	**0.56 %**	**(0.31)%**	63
64									64
65	Distribution Only Service	DOS	-	-	-	- %	- %	- %	65
66									66
67	Unbilled - DOS	Unbilled - DOS	-	-	-	- %	- %	- %	67
68									68
69	Total Distribution Only Service		-	-	-	- %	- %	- %	69
70									70
71	**Total - All Classes With DOS**		**$ 5,937,850**	**$ 2,639,046**	**$ (3,298,804)**	**(55.56)%**	**0.56 %**	**(0.31)%**	71

TABLE 13
SIERRA PACIFIC POWER COMPANY
d/b/a NV Energy
PRESENT & PROPOSED RATE REVENUE: ESPC
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	
			ESPC Revenue			Percent Change		Percentage Change	
Ln No	Rate Schedule Description		Present	Proposed	Difference [(c)-(b)]	in Component [(d)/(b)]	Percent Component Rev to Total Present Rev	to Total Revenue [(e)*(f)]	Ln No
1	Domestic Service	D-1	$ 21,830	$ 21,830	$ -	- %	0.01 %	- %	1
2	Domestic Multi-Family Service	DM-1	4,523	4,523	-	- %	0.01 %	- %	2
3	Domestic Service ESAP	D-1 ESAP	59	59	-	- %	0.01 %	- %	3
4	Domestic Multi-Family Service ESAP	DM-1 ESAP	20	20	-	- %	0.01 %	- %	4
5	Total Residential - Non-TOU		26,432	26,432	-	- %	0.01 %	- %	5
6									6
7	Optional Domestic Service - TOU	OD-1 TOU	249	249	-	- %	0.01 %	- %	7
8	Optional Domestic Service - TOU ESAP	OD-1 TOU ESAP	3	3	-	- %	0.01 %	- %	8
9	Optional Domestic Multi-Family Service - TOU	ODM-1 TOU	5	5	-	- %	0.01 %	- %	9
10	Optional Domestic Multi-Family Service - TOU ESAP	ODM-1 TOU ESAP	-	-	-	- %	- %	- %	10
11	Total Residential - TOU		257	257	-	- %	0.01 %	- %	11
12									12
13	**Total Residential**		**26,689**	**26,689**	**-**	**- %**	**0.01 %**	**- %**	13
14									14
15	Small General Service	GS-1	6,541	6,541	-	- %	0.01 %	- %	15
16	Small General Service ESAP	GS-1 ESAP	5	5	-	- %	0.01 %	- %	16
17	Optional General Service - Time-of-Use	OGS-1 TOU	259	259	-	- %	0.01 %	- %	17
18	Optional General Service - Time-of-Use ESAP	OGS-1 TOU ESAP	-	-	-	- %	- %	- %	18
19	Small General Service - SSR	GS-1 SSR	-	-	-	- %	- %	- %	19
20	Wireless Communication Service	WCS	1	1	-	- %	0.01 %	- %	20
21	Irrigation Service	IS-1	368	368	-	- %	0.01 %	- %	21
22	Interruptible Irrigation Service	IS-2	1,006	1,006	-	- %	0.01 %	- %	22
23	City of Elko Water Pumping	WP	69	69	-	- %	0.01 %	- %	23
24	Total Small General Service		8,249	8,249	-	- %	0.01 %	- %	24
25									25
26	Medium General Service -Secondary	GS-2S	13,466	13,466	-	- %	0.01 %	- %	26
27	Medium General Service - Primary	GS-2P	506	506	-	- %	0.01 %	- %	27
28	Medium General Service - Transmission	GS-2T	163	163	-	- %	0.01 %	- %	28
29	Medium General Service - TOU - Secondary	GS-2S TOU	4,026	4,026	-	- %	0.01 %	- %	29
30	Medium General Service - TOU - Primary	GS-2P TOU	595	595	-	- %	0.01 %	- %	30
31	Medium General Service - TOU - Transmission	GS-2T TOU	123	123	-	- %	0.01 %	- %	31
32	Optional Medium General Service - TOU - Secondary	OGS-2S TOU	2,967	2,967	-	- %	0.01 %	- %	32
33	Optional Medium General Service - TOU - Primary	OGS-2P TOU	29	29	-	- %	0.01 %	- %	33
34	Optional Medium General Service - TOU - Transmission	OGS-2T TOU	-	-	-	- %	- %	- %	34
35	Medium General Service - Secondary - SSR	GS-2S SSR	-	-	-	- %	- %	- %	35
36	Medium General Service - Primary - SSR	GS-2P SSR	-	-	-	- %	- %	- %	36
37	Medium General Service - Transmission - SSR	GS-2T SSR	10	10	-	- %	0.01 %	- %	37
38	Medium General Service - Secondary TOU - LSR	GS-2S TOU LSR	-	-	-	- %	- %	- %	38
39	Medium General Service - Primary TOU - LSR	GS-2P TOU LSR	-	-	-	- %	- %	- %	39
40	Medium General Service - Transmission TOU - LSR	GS-2T TOU LSR	24	24	-	- %	0.01 %	- %	40
41	Total Medium General Service		21,909	21,909	-	- %	0.01 %	- %	41
42									42
43	Large General Service - Secondary	GS-3S	3,463	3,463	-	- %	0.01 %	- %	43
44	Large General Service - Primary	GS-3P	4,441	4,441	-	- %	0.01 %	- %	44
45	Large General Service - Transmission	GS-3T	11,871	11,871	-	- %	0.01 %	- %	45
46	Large General Service - Secondary - LSR	GS-3S LSR	-	-	-	- %	- %	- %	46
47	Large General Service - Primary - LSR	GS-3P LSR	14	14	-	- %	0.01 %	- %	47
48	Large General Service - Transmission - LSR	GS-3T LSR	6,678	6,678	-	- %	0.01 %	- %	48
49	Total Large General Service		26,467	26,467	-	- %	0.01 %	- %	49
50									50
51	Large Transmission Service	GS-4	245	245	-	- %	0.01 %	- %	51
52									52
53	Street Lighting Service	SL	107	107	-	- %	0.00 %	- %	53
54	Outdoor Lighting Service	OLS	45	45	-	- %	0.00 %	- %	54
55	Total Lighting Service		152	152	-	- %	0.00 %	- %	55
56									56
57	**Total Non-Residential**		**57,022**	**57,022**	**-**	**- %**	**0.01 %**	**- %**	57
58									58
59	**Total - all classes**		**83,711**	**83,711**	**-**	**- %**	**0.01 %**	**- %**	59
60									60
61	Unbilled	Unbilled	(237)	(237)	-	- %	0.01 %	- %	61
62									62
63	**Total - all classes with Unbilled**		**83,474**	**83,474**	**-**	**- %**	**0.01 %**	**- %**	63
64									64
65	Distribution Only Service	DOS	28,072	28,072	-	- %	0.40 %	- %	65
66									66
67	Unbilled - DOS	Unbilled - DOS	221	221	-	- %	1.31 %	- %	67
68									68
69	Total Distribution Only Service		28,293	28,293	-	- %	0.40 %	- %	69
70									70
71	**Total - All Classes With DOS**		**$ 111,767**	**$ 111,767**	**$ -**	**- %**	**0.01 %**	**- %**	71

TABLE 14
SIERRA PACIFIC POWER COMPANY
d/b/a NV Energy
PRESENT & PROPOSED RATE REVENUE: ESDR
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

Ln No	(a) Rate Schedule Description		(b) ESDR Revenue Present	(c) ESDR Revenue Proposed	(d) Difference [(c)-(b)]	(e) Percent Change in Component [(d)/(b)]	(f) Percent Component Rev to Total Present Rev	(g) Percentage Change to Total Revenue [(e)*(f)]	Ln No
1	Domestic Service	D-1	$ 21,830	$ 21,830	$ -	- %	0.01 %	- %	1
2	Domestic Multi-Family Service	DM-1	4,523	4,523	-	- %	0.01 %	- %	2
3	Domestic Service ESAP	D-1 ESAP	59	59	-	- %	0.01 %	- %	3
4	Domestic Multi-Family Service ESAP	DM-1 ESAP	20	20	-	- %	0.01 %	- %	4
5	Total Residential - Non-TOU		26,432	26,432	-	- %	0.01 %	- %	5
6									6
7	Optional Domestic Service - TOU	OD-1 TOU	249	249	-	- %	0.01 %	- %	7
8	Optional Domestic Service - TOU ESAP	OD-1 TOU ESAP	3	3	-	- %	0.01 %	- %	8
9	Optional Domestic Multi-Family Service - TOU	ODM-1 TOU	5	5	-	- %	0.01 %	- %	9
10	Optional Domestic Multi-Family Service - TOU ESAP	ODM-1 TOU ESAP	-	-	-	- %	- %	- %	10
11	Total Residential - TOU		257	257	-	- %	0.01 %	- %	11
12									12
13	**Total Residential**		**26,689**	**26,689**	**-**	**- %**	**0.01 %**	**- %**	13
14									14
15	Small General Service	GS-1	6,541	6,541	-	- %	0.01 %	- %	15
16	Small General Service ESAP	GS-1 ESAP	5	5	-	- %	0.01 %	- %	16
17	Optional General Service - Time-of-Use	OGS-1 TOU	259	259	-	- %	0.01 %	- %	17
18	Optional General Service - Time-of-Use ESAP	OGS-1 TOU ESAP	-	-	-	- %	- %	- %	18
19	Small General Service - SSR	GS-1 SSR	-	-	-	- %	- %	- %	19
20	Wireless Communication Service	WCS	1	1	-	- %	0.01 %	- %	20
21	Irrigation Service	IS-1	368	368	-	- %	0.01 %	- %	21
22	Interruptible Irrigation Service	IS-2	1,006	1,006	-	- %	0.01 %	- %	22
23	City of Elko Water Pumping	WP	69	69	-	- %	0.01 %	- %	23
24	Total Small General Service		8,249	8,249	-	- %	0.01 %	- %	24
25									25
26	Medium General Service -Secondary	GS-2S	13,466	13,466	-	- %	0.01 %	- %	26
27	Medium General Service - Primary	GS-2P	506	506	-	- %	0.01 %	- %	27
28	Medium General Service - Transmission	GS-2T	163	163	-	- %	0.01 %	- %	28
29	Medium General Service - TOU - Secondary	GS-2S TOU	4,026	4,026	-	- %	0.01 %	- %	29
30	Medium General Service - TOU - Primary	GS-2P TOU	595	595	-	- %	0.01 %	- %	30
31	Medium General Service - TOU - Transmission	GS-2T TOU	123	123	-	- %	0.01 %	- %	31
32	Optional Medium General Service - TOU - Secondary	OGS-2S TOU	2,967	2,967	-	- %	0.01 %	- %	32
33	Optional Medium General Service - TOU - Primary	OGS-2P TOU	29	29	-	- %	0.01 %	- %	33
34	Optional Medium General Service - TOU - Transmission	OGS-2T TOU	-	-	-	- %	- %	- %	34
35	Medium General Service - Secondary - SSR	GS-2S SSR	-	-	-	- %	- %	- %	35
36	Medium General Service - Primary - SSR	GS-2P SSR	-	-	-	- %	- %	- %	36
37	Medium General Service - Transmission - SSR	GS-2T SSR	10	10	-	- %	0.01 %	- %	37
38	Medium General Service - Secondary TOU - LSR	GS-2S TOU LSR	-	-	-	- %	- %	- %	38
39	Medium General Service - Primary TOU - LSR	GS-2P TOU LSR	-	-	-	- %	- %	- %	39
40	Medium General Service - Transmission TOU - LSR	GS-2T TOU LSR	24	24	-	- %	0.01 %	- %	40
41	Total Medium General Service		21,909	21,909	-	- %	0.01 %	- %	41
42									42
43	Large General Service - Secondary	GS-3S	3,463	3,463	-	- %	0.01 %	- %	43
44	Large General Service - Primary	GS-3P	4,441	4,441	-	- %	0.01 %	- %	44
45	Large General Service - Transmission	GS-3T	11,871	11,871	-	- %	0.01 %	- %	45
46	Large General Service - Secondary - LSR	GS-3S LSR	-	-	-	- %	- %	- %	46
47	Large General Service - Primary - LSR	GS-3P LSR	14	14	-	- %	0.01 %	- %	47
48	Large General Service - Transmission - LSR	GS-3T LSR	6,678	6,678	-	- %	0.01 %	- %	48
49	Total Large General Service		26,467	26,467	-	- %	0.01 %	- %	49
50									50
51	Large Transmission Service	GS-4	245	245	-	- %	0.01 %	- %	51
52									52
53	Street Lighting Service	SL	107	107	-	- %	0.00 %	- %	53
54	Outdoor Lighting Service	OLS	45	45	-	- %	0.00 %	- %	54
55	Total Lighting Service		152	152	-	- %	0.00 %	- %	55
56									56
57	**Total Non-Residential**		**57,022**	**57,022**	**-**	**- %**	**0.01 %**	**- %**	57
58									58
59	**Total - all classes**		**83,711**	**83,711**	**-**	**- %**	**0.01 %**	**- %**	59
60									60
61	Unbilled	Unbilled	(237)	(237)	-	- %	0.01 %	- %	61
62									62
63	**Total - all classes with Unbilled**		**83,474**	**83,474**	**-**	**- %**	**0.01 %**	**- %**	63
64									64
65	Distribution Only Service	DOS	28,072	28,072	-	- %	0.40 %	- %	65
66									66
67	Unbilled - DOS	Unbilled - DOS	221	221	-	- %	1.31 %	- %	67
68									68
69	Total Distribution Only Service		28,293	28,293	-	- %	0.40 %	- %	69
70									70
71	**Total - All Classes With DOS**		**$ 111,767**	**$ 111,767**	**$ -**	**- %**	**0.01 %**	**- %**	71

TABLE 15
SIERRA PACIFIC POWER COMPANY
d/b/a NV Energy
ELECTRIC DEPARTMENT - NEVADA
PRESENT & PROPOSED RATE REVENUE: TYPICAL BILL CALCULATION
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

Ln No	(a) Description	kwh	(b) Present Rates	(c) Monthly Bill at Present Rates	(d) Proposed Rates	(e) Monthly Bill at Proposed Rates	(f) Difference [(e)-(c)]	(g) Percent Change	Ln No
1	**SCHEDULE D-1**								1
2	**Single-Family**								2
3	Average Monthly Usage (note 3)=	762							3
4									4
5	Customer Charge		$16.50	$16.50	$16.50	$ 16.50	$ -	- %	5
6	BTGR		0.05745	43.78	0.05745	43.78	-	- %	6
7	BTER		0.06440	49.07	0.06440	49.07	-	- %	7
8	DEAA\REPR		0.00677	5.16	0.00589	4.49	(0.67)	(0.57)%	8
9	EE		0.00172	1.31	0.00233	1.78	0.47	0.40 %	9
10	NDPP		0.00074	0.56	0.00074	0.56	-	- %	10
11	ESPC\ESDR		0.00002	0.02	0.00002	0.02	-	- %	11
12	UEC \ TRED		0.00111	0.85	0.00071	0.54	(0.31)	(0.26)%	12
13									13
14	TOTAL			**$117.25**		**$ 116.74**	**$ (0.51)**	**(0.43)%**	14
15									15
16									16
17									17
18									18
19	**SCHEDULE DM-1**								19
20	**Multi-Family**								20
21	Average Monthly Usage (note 3)=	451							21
22									22
23	Customer Charge		$8.00	$ 8.00	$8.00	$ 8.00	$ -	- %	23
24	BTGR		0.05566	25.10	0.05566	25.10	-	- %	24
25	BTER		0.06440	29.04	0.06440	29.04	-	- %	25
26	DEAA\REPR		0.00677	3.05	0.00589	2.66	(0.39)	(0.58)%	26
27	EE		0.00162	0.73	0.00223	1.01	0.28	0.42 %	27
28	NDPP		0.00074	0.33	0.00074	0.33	-	- %	28
29	ESPC\ESDR		0.00002	0.01	0.00002	0.01	-	- %	29
30	UEC \ TRED		0.00111	0.50	0.00071	0.32	(0.18)	(0.27)%	30
31									31
32	TOTAL			**$ 66.76**		**$ 66.47**	**$ (0.29)**	**(0.43)%**	32
33									33
34									34
35	Notes:								35
36	1) Present and Proposed monthly bill amounts shown above do not include any franchise or business license taxes or assessments.								36
37	2) Total percentage change may not match Table 1 as the average monthly usage has been rounded.								37
38	3) Average monthly usage was calculated based on the most recent 12 months sales and customer counts data (as of December 31, 2023).								38

EXHIBIT H

Sierra Pacific Power Company
Calculation of TRED Rate
For the Twelve Months Ended September 30, 2025
(In Thousands)

Exhibit H
Page 1 of 2
Ahlstedt

	(a)	(b)	(c)	(d)	
		Highest Forecasted Expense		TRED Expense Based on	
Ln	Description	Month	Amount	Forecast	Ln
1					1
2	**2024**				2
3	October			$ 409	3
4	November			208	4
5	December			151	5
6	**2025**				6
7	January			182	7
8	February			263	8
9	March			432	9
10	April			676	10
11	May			867	11
12	June			958	12
13	July			966	13
14	August			812	14
15	September			629	15
16	**Total Forecasted TRED Expenses** [(1)]			$ 6,554	16
17					17
18	Add: Required Reserve Balance [(2)]	July 2025	$ 966	2,898	18
19					19
20	Less: TRED Trust Balance at Rate Effective Date (Page 2 of 2)			(6,823)	20
21					21
22	TRED Revenue Requirement			$ 2,629	22
23					23
24	Historical Sales (MWh, Exhibit H-1)			8,247,016	24
25					25
26	**TRED Rate per kWh**			**$ 0.00032**	26
27					27
28	[(1)] Forecasted expenses based on SPP Electric Projection Dec23 actual Jan24 risk.				28
29	[(2)] Required reserve balance is three times the highest projected monthly expense.				29

Sierra Pacific Power Company
TRED Trust Balance at Rate Effective Date
(In Thousands)

Exhibit H

Ahlstedt

	(a)	(b)	(c)	(d)	(e)	(f)	
Ln	Month	Beginning Balance	Funding [1]	Disbursements [2]	Interest [3]	Ending Balance	Ln
1							1
2	Balance at December 31, 2023	$ 7,369				$ 7,369	2
3							3
4	2024 (Forecasted)						4
5	January (actuals)		$ 499	$ (179)	$ 34	$ 7,723	5
6	February		555	(269)	35	8,043	6
7	March		509	(425)	36	8,163	7
8	April		512	(667)	35	8,042	8
9	May		496	(856)	34	7,716	9
10	June		485	(946)	32	7,286	10
11	July		555	(954)	30	6,917	11
12	August		639	(802)	30	6,783	12
13	September		632	(622)	30	6,823	13
14							14
15	Balance at September 30, 2024	$ 7,369	$ 4,881	$ (5,722)	$ 295	$ 6,823	15
16							16

17 [1] Funding reflects actuals through January 2024 and forecasted transactions through September 2024. 17

18 18

19 [2] Forecasted disbursements based on SPP Electric Projection Dec23 Actual Jan24 Risk. 19

20 20

21 [3] Interest calculated utilizing 0.4383% based on actual percentage as of December 2023. 21

EXHIBIT H-1

Sierra Pacific Power Company
d/b/a NV Energy
ELECTRIC DEPARTMENT - NEVADA
kWh SALES - BILLED AND UNBILLED
FOR THE TWELVE MONTHS ENDED DECEMBER 2023

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	
							Nevada			
Ln	Month	Grand Total	Off System Sales	Total System Sales	FERC-California	FERC-Other	Subtotal Nevada	IS-2	Subject to TRED	Ln
1		(c)+(d)		(e)+(f)+(g)					(g)-(h)-(i)	1
2										2
3	January	832,342,813	6,130,625	826,212,188	85,265,663	689,585	740,256,940	(165,637)	740,422,577	3
4	February	731,836,171	6,038,349	725,797,822	60,549,410	696,282	664,552,130	(6,514)	664,558,644	4
5	March	767,981,025	15,981,849	751,999,176	53,748,270	664,930	697,585,976	259,190	697,326,786	5
6	April	708,313,563	24,663,713	683,649,850	47,200,650	582,518	635,866,682	4,521,870	631,344,812	6
7	May	683,882,725	5,204,030	678,678,695	26,340,697	584,583	651,753,415	13,622,680	638,130,735	7
8	June	686,471,079	11,731,217	674,739,862	14,330,528	620,190	659,789,144	18,501,164	641,287,980	8
9	July	922,043,072	59,636,564	862,406,508	22,809,776	613,964	838,982,768	24,858,308	814,124,460	9
10	August	838,228,862	11,123,291	827,105,571	34,570,704	753,440	791,781,427	21,586,645	770,194,782	10
11	September	648,103,006	(40,709,078)	688,812,084	23,827,453	684,268	664,300,363	14,643,306	649,657,057	11
12	October	664,426,896	13,485,481	650,941,415	26,634,427	607,901	623,699,087	3,680,585	620,018,502	12
13	November	721,429,115	6,793,156	714,635,959	35,435,759	612,200	678,588,000	(890,818)	679,478,818	13
14	December	768,435,223	5,052,868	763,382,355	62,320,572	645,289	700,416,494	(54,051)	700,470,545	14
15										15
16										16
17	Total	8,973,493,550	125,132,065	8,848,361,485	493,033,909	7,755,150	8,347,572,426	100,556,728	8,247,015,698	17

EXHIBIT I

Sierra Pacific Power Company d/b/a NV Energy
Electric Department - Nevada
Calculation of Renewable Energy Program Rate
Cumulative Balances At December 31, 2023
Program Year Ending June 30, 2025

Exhibit I
Page 1 of 2
Ahlstedt

	(a)	(b)	(c)	(d)	(e)	
			Part (a)	Part (b)		
Ln	Description	Reference	Annual Plan Costs	Cumulative Balance	Program Rate	Ln
1	Renewable Energy Program Rate:					1
2						2
3	Solar Energy Systems Incentive Program					3
4						4
5	Cost Basis for Solar Program Rate Components	(1) / (2)	$ 31,191	$ 3,654,237		5
6						6
7	kWh Sales (Billed & Unbilled)	Exhibit I, pg 3 / I-1	9,310,644,898	8,247,015,698		7
8						8
9	Solar Program Rate		$ 0.00000	$ 0.00044	$ 0.00044	9
10						10
11						11
12						12
13	Small Energy Storage Program					13
14						14
15	Cost Basis for Small Energy Storage Program Rate Components	(1) / (2)	$ 141,898	$ (673,666)		15
16						16
17	kWh Sales (Billed & Unbilled)	Exhibit I, pg 3 / I-1	9,310,644,898	8,247,015,698		17
18						18
19	Small Energy Storage Program Rate		$ 0.00002	$ (0.00008)	$ (0.00006)	19
20						20
21						21
22						22
23	Large Energy Storage Program					23
24						24
25	Cost Basis for Large Energy Storage Program Rate Components	(1) / (3)	$ 663,840	$ (79,322)		25
26						26
27	kWh Sales (Billed & Unbilled)	Exhibit I, pg 3 / I-1	9,310,644,898	8,247,015,698		27
28						28
29	Large Energy Storage Program Rate		$ 0.00007	$ (0.00001)	$ 0.00006	29
30						30
31						31
32						32
33	Electric Vehicle Infrastructure Demonstration Program					33
34						34
35	Cost Basis for EV Infrastructure Demonstration Program Rate Components	(1) / (4)	$ 1,171,384	$ 2,651,684		35
36						36
37	kWh Sales (Billed & Unbilled)	Exhibit I, pg 3 / I-1	9,310,644,898	8,247,015,698		37
38						38
39	Electric Vehicle Infrastructure Demonstration Program Rate		$ 0.00013	$ 0.00032	$ 0.00045	39
40						40
41						41
42	Total Renewable Energy Program Rate		$ 0.00022	$ 0.00067	$ 0.00089	42
43						43
44	(1) Exhibit Sheikh Direct - 5					44
45	(2) Exhibit Sheikh Direct - 2D					45
46	(3) Exhibit Sheikh Direct - 2E					46
47	(4) Exhibit Sheikh Direct - 2F					47

Sierra Pacific Power Company d/b/a NV Energy
Electric Department - Nevada
Forecasted kWh Energy Sales
Program Year Ending June 30, 2025

	(a)		(b)	(c)	(e)	(f)	(g)	(h)	
			Nevada						
			(e)-(c)-(d)					(e)+(f)+(g)	
Ln	Year	Month	Ex. Interruptible Irrigation	IS-2 Interruptible Irrigation	Total	FERC-CA	FERC-Other	Total	Ln
1									1
2	2024	July	907,615,147	27,031,909	934,647,056	44,575,000	755,661	979,977,717	2
3		August	876,187,390	28,862,857	905,050,247	42,919,000	740,635	948,709,882	3
4		September	771,336,582	23,225,701	794,562,283	39,244,000	700,017	834,506,300	4
5		October	720,494,440	8,922,697	729,417,137	42,550,000	633,323	772,600,460	5
6		November	740,564,703	1,621,690	742,186,393	50,174,000	726,378	793,086,771	6
7		December	813,078,211	41,596	813,119,807	66,617,000	797,894	880,534,701	7
8	2025	January	810,777,354	410,778	811,188,132	50,174,000	726,378	862,088,510	8
9		February	718,000,661	140,532	718,141,192	50,174,000	726,378	769,041,570	9
10		March	736,679,470	537,064	737,216,534	50,174,000	726,378	788,116,912	10
11		April	707,692,862	4,500,836	712,193,698	50,174,000	726,378	763,094,076	11
12		May	694,510,912	15,649,702	710,160,614	50,174,000	726,378	761,060,992	12
13		June	813,707,166	23,621,148	837,328,314	50,174,000	726,378	888,228,692	13
14									14
15		Total	9,310,644,898	134,566,510	9,445,211,409	587,123,000	8,712,175	10,041,046,584	15
			To Exh I, pg 1-2, Col (c)						

EXHIBIT I-1

Sierra Pacific Power Company d/b/a NV Energy
Electric Department - Nevada
kWh Sales - Billed and Unbilled
For The Twelve Months Ended December 31, 2023

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	
						Nevada				
			Off System	Total			Subtotal		Subject to	
Ln	Month	Grand Total	Sales	System Sales	FERC-California	FERC-Other	Nevada	IS-2	DEAA	Ln
1		(c)+(d)		(e)+(f)+(g)					(g)-(h)-(i)	1
2										2
3	January, 2023	832,342,813	6,130,625	826,212,188	85,265,663	689,585	740,256,940	(165,637)	740,422,577	3
4	February	731,836,171	6,038,349	725,797,822	60,549,410	696,282	664,552,130	(6,514)	664,558,644	4
5	March	767,981,025	15,981,849	751,999,176	53,748,270	664,930	697,585,976	259,190	697,326,786	5
6	April	708,313,563	24,663,713	683,649,850	47,200,650	582,518	635,866,682	4,521,870	631,344,812	6
7	May	683,882,725	5,204,030	678,678,695	26,340,697	584,583	651,753,415	13,622,680	638,130,735	7
8	June	686,471,079	11,731,217	674,739,862	14,330,528	620,190	659,789,144	18,501,164	641,287,980	8
9	July	922,043,072	59,636,564	862,406,508	22,809,776	613,964	838,982,768	24,858,308	814,124,460	9
10	August	838,228,862	11,123,291	827,105,571	34,570,704	753,440	791,781,427	21,586,645	770,194,782	10
11	September	648,103,006	(40,709,078)	688,812,084	23,827,453	684,268	664,300,363	14,643,306	649,657,057	11
12	October	664,426,896	13,485,481	650,941,415	26,634,427	607,901	623,699,087	3,680,585	620,018,502	12
13	November	721,429,115	6,793,156	714,635,959	35,435,759	612,200	678,588,000	(890,818)	679,478,818	13
14	December	768,435,223	5,052,868	763,382,355	62,320,572	645,289	700,416,494	(54,051)	700,470,545	14
15										15
16										16
17	Total	8,973,493,550	125,132,065	8,848,361,485	493,033,909	7,755,150	8,347,572,426	100,556,728	8,247,015,698	17
18									To Exh I, pg 1-2, Col (d)	18

EXHIBIT J

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
Line No.	**Class**	**2024 Forecast Program Costs**	**Gen & Energy Allocator (After IS2 Subsidy)[1]**	**Program Costs - Allocated**	**2024 Forecast Sales**	**Initial Base Rate**	**2024 Forecast Sales (Classes set on OAC)**	**Revenue Credit and (Shortfall)**	**Revenue Req. Including Credit/(Shortfall)**	**% of Total**	**Spread of (Shortfall)**	**Resulting Revenue Req.**	**2024 Forecast Sales (w/ Rev. Credit Classes)**	**Base EEPR Rate**	Line No.
1		(Exhibit J-2)	(Combined MCS of G&E)	(Total Rev Req) x (c)	(Exhibit J-1)	(d) / (e)	(Exhibit J-1)	OAC Base Rate (f) x (g)	(d) + OAC (h)	(i) / (Total)		(i) + (k)	(e) + OAC (g)	(l) / (m)	1
2	DM-1		6.51%	$ 1,033,868.73	462,149,270	$ 0.00224			$ 1,034,971	6.48%	$ (5,857)	$ 1,029,460	462,762,924	**$ 0.00222**	2
3	D-1		32.41%	5,146,843	2,247,660,063	0.00229			5,180,732	32.44%	(29,319)	5,300,377	2,290,617,867	**0.00231**	3
4	GS-1		6.90%	1,095,317	667,588,942	0.00164			1,095,498	6.86%	(6,200)	1,106,191	673,838,211	**0.00164**	4
5	GS-2S		14.80%	2,350,323	1,413,823,661	0.00166			2,350,323	14.72%	(13,301)	2,337,022	1,413,823,661	**0.00165**	5
6	GS-2P		0.35%	55,643	36,009,859	0.00155			55,645	0.35%	(315)	55,330	36,011,317	**0.00154**	6
7	GS-2T		0.07%	10,484	8,258,157	0.00127			11,666	0.07%	(66)	11,600	9,189,437	**0.00126**	7
8	GS-2S-TOU		4.89%	777,167	434,328,360	0.00179			777,167	4.87%	(4,398)	772,769	434,328,360	**0.00178**	8
9	GS-2P-TOU		0.37%	59,411	34,779,632	0.00171			59,411	0.37%	(336)	59,074	34,779,632	**0.00170**	9
10	GS-2T-TOU		0.23%	37,284	26,009,521	0.00143			38,337	0.24%	(217)	38,120	26,743,694	**0.00143**	10
11	GS-3S		4.32%	685,332	406,896,561	0.00168			685,332	4.29%	(3,878)	681,454	406,896,561	**0.00167**	11
12	GS-3P		5.43%	861,586	573,296,355	0.00150			871,389	5.46%	(4,931)	866,458	579,819,575	**0.00149**	12
13	GS-3T		17.42%	2,765,901	2,251,635,272	0.00123			2,798,732	17.53%	(15,839)	2,782,893	2,278,361,558	**0.00122**	13
14	GS-4		0.25%	39,772	25,588,512	0.00155			39,772	0.25%	(225)	39,547	25,588,512	**0.00155**	14
15	OGS-1		0.30%	48,403	30,103,320	0.00161			48,403	0.30%	(274)	48,129	30,103,320	**0.00160**	15
16	OGS-2S		3.25%	515,662	306,777,805	0.00168			515,662	3.23%	(2,918)	512,744	306,777,805	**0.00167**	16
17	OGS-2P		0.00%	-	-				-	0.00%	-	-	-	**0.00154**	17
18	OGS-2T		0.00%	-	-				-	0.00%	-	-	-	**0.00126**	18
19	IS-1		1.25%	198,803	78,100,561	0.00255			198,803	1.24%	(1,125)	197,678	78,100,561	**0.00253**	19
20	IS-2[1]		0.00%	-	134,164,483	-			-	0.00%	-	-	134,164,483	-	20
21	WP		0.09%	14,693	7,898,994	0.00186			14,693	0.09%	(83)	14,610	7,898,994	**0.00185**	21
22	SL		0.12%	19,125	14,494,929	0.00132			19,125	0.12%	(108)	19,017	14,494,929	**0.00131**	22
23	OLS		0.04%	7,070	4,891,949	0.00145			7,070	0.04%	(40)	7,030	4,891,949	**0.00144**	23
24	DM-1 NEM[2]		0.00%	348	120,734	0.00288			348	0.00%	(2)				24
25	D-1 NEM[2]		0.88%	139,477	26,215,924	0.00532			149,811	0.94%	(848)				25
26	GS-1 NEM[2]		0.11%	16,989	6,139,392	0.00277			16,989	0.11%	(96)				26
27															27
28	ODM-1						492,919	$ 1,103							28
29	OD-1						14,799,505	33,889							29
30	D-1-NEM-TOU						1,942,376	10,334							30
31	GS-1-NEM-TOU						-	-							31
32	SSR-2 (GS-1)						23,616	39							32
33	WCS (GS-1)						86,260	142							33
34	SSR-3 (GS-2P)						1,458	2							34
35	SSR-3 (GS-2T)						931,280	1,182							35
36	LSR-1 (GS-2T-TOU)						734,173	1,052							36
37	LSR-2 (GS-3P)						6,523,220	9,804							37
38	LSR-2 (GS-3T)						26,726,287	32,830							38
39															39
40	Total	$ 15,879,503	100.00%	$ 15,879,503	9,196,932,257	$ 0.00173	52,261,093	$ 90,377	$ 15,969,880	100.00%	$ (90,377)	$ 15,879,503	9,249,193,349	$ 0.00172	40
41															41
42															42
43	[1]Per paragraph 31 of the Commission order in Docket no. 13-10002, the IS-2 class is not required to pay energy efficiency surcharge rates.														43
44	[2]NEM customers are required to pay the same rates as their OAC. Therefore the NEM sales and revenue allocation has been combined with the full requirements rate schedule														44
45															45

Line No.	(a) Class	(b) 2024 Forecast Program Cost Adder	(c) Gen & Energy Allocator (After IS2 Subsidy)[1]	(d) Program Costs - Allocated	(e) 2024 Forecast Sales	(f) Initial Base Rate	(g) 2024 Forecast Sales (Classes set on OAC)	(h) Revenue Credit and (Shortfall)	(i) Revenue Req. Including Credit/(Shortfall)	(j) % of Total	(k) Spread of (Shortfall)	(l) Resulting Revenue Req.	(m) 2024 Forecast Sales (w/ Rev. Credit Classes)	(n) Base EEIR Rate	Line No.
1		(Adder based on Exhibit J-2)	(Combined MCS of G&E)	(Total Rev Req) x (e)	(Exhibit J-1)	(d) / (e)	(Exhibit J-1)	OAC Base Rate (f) x (g)	(d) + OAC (h)	(i) / (Total)		(i) + (k)	(e) + OAC (g)	(l) / (m)	1
2	DM-1		6.51%	$ 85,520.65	462,149,270	$ 0.00019			$ 85,612	6.48%	$ (484)	$ 85,156	462,762,924	**$ 0.00018**	2
3	D-1		32.41%	425,742	2,247,660,063	0.00019			428,545	32.44%	(2,425)	438,442	2,290,617,867	**0.00019**	3
4	GS-1		6.90%	90,604	667,588,942	0.00014			90,619	6.86%	(513)	91,503	673,838,211	**0.00014**	4
5	GS-2S		14.80%	194,417	1,413,823,661	0.00014			194,417	14.72%	(1,100)	193,316	1,413,823,661	**0.00014**	5
6	GS-2P		0.35%	4,603	36,009,859	0.00013			4,603	0.35%	(26)	4,577	36,011,317	**0.00013**	6
7	GS-2T		0.07%	867	8,258,157	0.00011			965	0.07%	(5)	960	9,189,437	**0.00010**	7
8	GS-2S-TOU		4.89%	64,287	434,328,360	0.00015			64,287	4.87%	(364)	63,923	434,328,360	**0.00015**	8
9	GS-2P-TOU		0.37%	4,914	34,779,632	0.00014			4,914	0.37%	(28)	4,887	34,779,632	**0.00014**	9
10	GS-2T-TOU		0.23%	3,084	26,009,521	0.00012			3,171	0.24%	(18)	3,153	26,743,694	**0.00012**	10
11	GS-3S		4.32%	56,690	406,896,561	0.00014			56,690	4.29%	(321)	56,369	406,896,561	**0.00014**	11
12	GS-3P		5.43%	71,270	573,296,355	0.00012			72,081	5.46%	(408)	71,673	579,819,575	**0.00012**	12
13	GS-3T		17.42%	228,793	2,251,635,272	0.00010			231,508	17.53%	(1,310)	230,198	2,278,361,558	**0.00010**	13
14	GS-4		0.25%	3,290	25,588,512	0.00013			3,290	0.25%	(19)	3,271	25,588,512	**0.00013**	14
15	OGS-1		0.30%	4,004	30,103,320	0.00013			4,004	0.30%	(23)	3,981	30,103,320	**0.00013**	15
16	OGS-2S		3.25%	42,655	306,777,805	0.00014			42,655	3.23%	(241)	42,414	306,777,805	**0.00014**	16
17	OGS-2P		0.00%	-	-				-	0.00%	-	-	-	**0.00013**	17
18	OGS-2T		0.00%	-	-				-	0.00%	-	-	-	**0.00010**	18
19	IS-1		1.25%	16,445	78,100,561	0.00021			16,445	1.24%	(93)	16,352	78,100,561	**0.00021**	19
20	IS-2[1]		0.00%	-	134,164,483	-			-	0.00%	-	-	134,164,483	**-**	20
21	WP		0.09%	1,215	7,898,994	0.00015			1,215	0.09%	(7)	1,209	7,898,994	**0.00015**	21
22	SL		0.12%	1,582	14,494,929	0.00011			1,582	0.12%	(9)	1,573	14,494,929	**0.00011**	22
23	OLS		0.04%	585	4,891,949	0.00012			585	0.04%	(3)	582	4,891,949	**0.00012**	23
24	DM-1 NEM[2]		0.00%	29	120,734	0.00024			29	0.00%	(0)				24
25	D-1 NEM[2]		0.88%	11,537	26,215,924	0.00044			12,392	0.94%	(70)				25
26	GS-1 NEM[2]		0.11%	1,405	6,139,392	0.00023			1,405	0.11%	(8)				26
27															27
28	ODM-1						492,919	$ 91							28
29	OD-1						14,799,505	2,803							29
30	D-1-NEM-TOU						1,942,376	855							30
31	GS-1-NEM-TOU						-	-							31
32	SSR-2 (GS-1)						23,616	3							32
33	WCS (GS-1)						86,260	12							33
34	SSR-3 (GS-2P)						1,458	0							34
35	SSR-3 (GS-2T)						931,280	98							35
36	LSR-1 (GS-2T-TOU)						734,173	87							36
37	LSR-2 (GS-3P)						6,523,220	811							37
38	LSR-2 (GS-3T)						26,726,287	2,716							38
39															39
40	Total	**$ 1,313,538**	100.00%	$ 1,313,538	9,196,932,257	$ 0.00014	52,261,093	$ 7,476	$ 1,321,013	100%	$ (7,476)	$ 1,313,538	9,249,193,349	$ 0.00014	40
41															41
42															42
43	[1]Per paragraph 31 of the Commission order in Docket no. 13-10002, the IS-2 class is not required to pay energy efficiency surcharge rates.														43
44	[2]NEM customers are required to pay the same rates as their OAC. Therefore the NEM sales and revenue allocation has been combined with the full requirements rate schedule														44
45															45

Updated Forecast:	$ 15,879,503
Rate of Return	8.27%
EEIR	$ 1,313,538
Total w/ EEIR	$ 17,193,041

EXHIBIT J-1

Exhibit J-1
2024 SPPC Energy Efficiency Filing
2024 Sales Forecast (kWh)

Line No.	(a) Customer Class	(b) Jan-24	(c) Feb-24	(d) Mar-24	(e) Apr-24	(f) May-24	(g) Jun-24	(h) Jul-24	(i) Aug-24	(j) Sep-24	(k) Oct-24	(l) Nov-24	(m) Dec-24	(n) 2024 Total	Line No.
1	DM-1	43,019,852	37,017,548	35,439,351	31,821,634	29,700,313	38,572,699	49,153,191	48,080,989	37,267,522	31,756,950	36,495,330	43,823,893	462,149,270	1
2	DM-1-NEM	14,490	9,936	8,586	5,737	5,873	10,779	14,669	12,159	9,064	7,605	8,542	13,295	120,734	2
3	D-1	210,008,623	178,028,027	170,019,231	153,617,676	138,162,102	189,797,722	247,039,426	233,988,178	174,742,933	152,279,141	179,912,775	220,064,230	2,247,660,063	3
4	D-1-NEM	3,465,531	2,505,169	1,180,601	784,000	928,438	1,854,581	3,111,158	2,650,943	1,700,512	1,748,857	2,039,558	4,246,574	26,215,924	4
5	GS-1	54,033,933	52,409,660	57,331,495	53,353,887	54,015,735	59,810,310	57,581,779	54,021,334	54,056,283	55,205,311	56,473,479	59,295,736	667,588,942	5
6	GS-1-NEM	626,812	485,468	458,766	298,041	311,327	460,334	625,472	555,006	425,967	465,278	720,406	706,517	6,139,392	6
7	GS-2S	127,070,821	99,411,209	115,079,687	106,809,659	106,425,066	118,777,699	142,771,520	142,766,040	116,584,648	106,195,157	110,249,261	121,682,893	1,413,823,661	7
8	GS-2P	3,172,346	3,194,765	3,064,240	3,080,974	2,652,667	3,585,197	3,132,432	2,704,224	3,416,125	2,474,842	1,687,152	3,844,893	36,009,859	8
9	GS-2T	831,279	764,387	1,347,647	856,045	265,218	468,943	1,779,759	617,970	(988,434)	550,196	979,488	785,659	8,258,157	9
10	GS-2S-TOU	24,812,746	29,133,826	31,927,586	32,823,688	39,136,391	45,883,347	44,770,750	42,759,131	40,169,145	41,168,158	30,287,520	31,456,071	434,328,360	10
11	GS-2P-TOU	4,378,657	4,096,317	6,060,764	4,073,218	1,328,279	1,676,856	1,614,748	1,493,093	1,966,362	2,104,097	5,525,275	461,967	34,779,632	11
12	GS-2T-TOU	2,629,094	1,570,587	1,854,985	2,198,797	3,362,183	1,505,205	2,785,010	2,287,711	2,189,411	2,304,274	670,451	2,651,813	26,009,521	12
13	GS-3S	33,936,426	31,695,888	31,821,429	29,951,718	28,846,135	33,352,641	41,793,406	40,571,318	38,096,644	34,100,060	30,454,454	32,276,442	406,896,561	13
14	GS-3P	48,386,967	43,355,609	40,613,126	41,995,381	47,124,337	48,019,087	50,791,260	52,174,034	48,637,362	53,135,340	47,625,462	51,438,389	573,296,355	14
15	GS-3T	193,139,130	187,291,880	177,120,189	201,120,733	189,026,963	162,050,116	194,467,843	186,725,951	197,420,986	183,160,003	191,438,253	188,673,225	2,251,635,272	15
16	GS-4	3,229,097	2,865,145	3,071,685	3,064,371	1,012,954	5,203,032	2,943,135	787,621	877,550	805,683	885,962	842,278	25,588,512	16
17	OGS-1	2,470,675	2,176,775	2,410,437	2,376,532	2,435,887	2,547,373	2,717,476	2,807,517	2,562,596	2,511,765	2,432,089	2,654,196	30,103,320	17
18	OGS-2S	25,187,975	19,691,766	23,390,313	23,428,180	26,677,663	27,587,580	30,606,508	31,967,913	27,806,572	24,944,437	22,460,161	23,028,738	306,777,805	18
19	OGS-2P	-	-	-	-	-	-	-	-	-	-	-	-	-	19
20	OGS-2T	-	-	-	-	-	-	-	-	-	-	-	-	-	20
21	IS-1	1,229,261	1,254,584	1,692,485	3,878,417	8,501,286	11,253,819	14,734,324	14,189,750	12,136,842	6,030,596	1,702,699	1,496,498	78,100,561	21
22	IS-2	407,097	139,272	532,251	4,460,501	15,509,452	23,409,459	27,031,909	28,862,857	23,225,701	8,922,697	1,621,690	41,596	134,164,483	22
23	WP	314,748	378,186	413,738	454,470	659,868	840,453	1,141,615	1,245,882	945,388	571,333	527,523	405,790	7,898,994	23
24	SL	1,217,142	1,225,664	1,221,060	1,218,217	1,216,900	1,209,208	1,204,459	1,199,447	1,195,230	1,198,598	1,196,966	1,192,038	14,494,929	24
25	OLS	414,362	393,470	423,884	406,373	413,771	414,271	407,895	412,981	407,141	396,668	396,898	404,234	4,891,949	25
26		783,997,063	699,095,139	706,483,536	702,078,249	697,718,807	778,290,713	922,219,745	892,882,049	784,851,550	712,037,047	725,791,394	791,486,966	9,196,932,257	26
27															27
28															28
29	ODM-1	44,870	38,466	41,657	34,745	34,177	33,873	45,288	45,180	35,092	40,068	47,515	51,988	492,919	29
30	OD-1	1,333,284	1,152,233	1,138,736	1,073,794	946,842	1,154,966	1,472,619	1,475,246	1,091,216	1,097,267	1,303,974	1,559,328	14,799,505	30
31	D-1-NEM-TOU	238,852	175,842	171,201	103,898	89,462	114,082	157,047	186,643	138,783	131,437	165,184	269,944	1,942,376	31
32	GS-1-NEM-TOU	-	-	-	-	-	-	-	-	-	-	-	-	-	32
33	SSR-2 (GS-1)	487	1,251	190	183	1,439	112	9,795	61	3,123	492	3,317	3,168	23,616	33
34	WCS	7,188	7,188	7,188	7,188	7,188	7,188	7,188	7,188	7,188	7,188	7,188	7,188	86,260	34
35	SSR-3 (GS-2P)	-	-	-	-	119	119	1,219	-	-	-	-	-	1,458	35
36	SSR-3 (GS-2T)	60,189	58,345	50,121	100,256	68,002	71,956	17,314	26,412	136,883	134,690	91,405	115,705	931,280	36
37	LSR-1 (GS-2T-TOU)	10,756	11,208	13,107	9,764	56,200	56,200	(37,561)	5,341	17,041	340,586	139,028	112,505	734,173	37
38	LSR-2 (GS-3P)	385,467	118,737	108,090	120,546	117,674	117,674	652,117	-	2,448,425	927,068	779,437	747,985	6,523,220	38
39	LSR-2 (GS-3T)	2,202,082	2,201,291	1,736,216	2,509,600	2,173,860	2,375,721	2,552,502	2,184,764	2,492,919	2,094,346	2,199,165	2,003,819	26,726,287	39
40		4,283,176	3,764,562	3,266,506	3,959,974	3,494,963	3,931,891	4,877,529	3,930,837	6,370,670	4,773,143	4,736,214	4,871,630	52,261,093	40
41															41
42															42
43													Total 2023:	9,249,193,349	43
44															44
45															45

EXHIBIT J-2

Sierra Pacific Power Company
d/b/a NV Energy
2024 Demand Side Management Program Costs

	(a)	(b)	
Line No.	**Sierra Pacific Power DSM Programs**	**2024 ($) Budget [1]**	**Line No.**
1	Energy Education	$310,000	1
2	Energy Reports	$457,060	2
3	Online Energy Assessments	$203,607	3
4	Program Development	$370,000	4
5	In-Home Energy Assessments	$493,333	5
6	Residential Equipment and Plug Loads	$1,645,000	6
7	Residential Codes and New Construction	$25,000	7
8	Low Income	$1,416,000	8
9	Direct Install and Deep Retrofits	$610,000	9
10	Residential Demand Response - Manage	$900,000	10
11	Residential Demand Response - Build	$1,937,155	11
12	Energy Smart Schools	$770,000	12
13	Business Energy Services	$5,700,000	13
14	Commercial Demand Response - Manage	$400,000	14
15	Commercial Demand Response - Build	$642,348	15
16	**Total Programs Costs [2]**	**$ 15,879,503**	16

[1] The Budget was approved by the Commission's Order issued on November 2, 2023, in Docket No. 23-06044.

[2] The total program costs do not reflect DSM recapture amounts from the 704B applications in Docket Nos. 16-11034 or 18-12019. The resulting reductions to the approved DSM program budgets shown in this exhibit are included in the Base EEPR rate calcuation shown for all classes in Exhibit J.

EXHIBIT K

Sierra Pacific Power Company
d/b/a NV Energy
Calculation Of Energy Efficiency
Program And Implementation Amortization Rates
At December 31, 2023

	(a)	(b)		(c)	
Ln	Description	Ref		Total	Ln
1	Energy Efficiency Program				1
2	Beginning Balance	K-1, p 1	$	-	2
3	Program Costs	K-1, p 1		13,457,416	3
4	EEPR Base Revenue	K-1, p 1		(14,049,921)	4
5	Deferral	K-1, p 1		(592,505)	5
6	Adjustments	K-1, p 1		(230,556)	6
7	Subtotal			(823,061)	7
8					8
9	Carrying Charges	K-1, p 1		(612,847)	9
10	Subtotal			(1,435,907)	10
11					11
12	Energy Efficiency Program Cumulative Balance		$	(1,435,907)	12
13					13
14	kWh Sales (Billed and Unbilled)	D-2		8,247,015,698	14
15					15
16	Energy Efficiency Program Amortization Rate per kWh			($0.00017)	16
17					17
18	Energy Efficiency Implementation				18
19	Estimated Savings	K-2, p 1	$	1,323,973	19
20	EEIR Base Revenue	K-2, p 1		(1,121,662)	20
21	Deferral Estimate	K-2, p 1		202,310	21
22	Deferral True Up	K-2, p 1		(158,774)	22
23	Adjustments	K-2, p 1		14,885	23
24	Subtotal			58,421	24
25	Carrying Charges	K-2, p 1		(41,962)	25
26	Subtotal			16,460	26
27					27
28	Energy Efficiency Implementation Balance	K-2, p 1	$	16,460	28
29					29
30	kWh Sales (Billed and Unbilled)	D-2		8,247,015,698	30
31					31
32	Energy Efficiency Implementation Amortization Rate per kWh			$0.00000	32

EXHIBIT K-1

Sierra Pacific Power Company
d/b/a NVEnergy
Energy Efficiency Program Cost Deferral Summary

Ln	(a)	(b) January	(c) February	(d) March	(e) April	(f) May	(g) June	(h) July	(i) August	(j) September	(k) October	(l) November	(m) December	(n) Summary of Annual Activity	Ln
1	Period 12							2021							1
2	Account No. 182-360														2
3	Beginning Balance	(3,709,944)	(3,264,659)	(2,864,081)	(2,442,858)	(2,061,773)	(1,676,552)	(1,288,601)	(796,783)	(331,495)	61,466	-	-	(3,709,944)	3
4	Energy Efficiency Program Costs	-	-	-	-	-	-	-	-	-	-			-	4
5	EEPR Base Revenue	-	-	-	-	-	-	-	-	-	-		-	-	5
6	EEPR Amortization Revenue	445,285	400,579	421,223	381,085	385,220	387,952	491,817	465,288	392,961	-	-	-	3,771,410	6
7	Adjustments	-	-	-	-	-	-	-	-	-	(61,466)	-	-	(61,466)	7
8	Subtotal	(3,264,659)	(2,864,081)	(2,442,858)	(2,061,773)	(1,676,552)	(1,288,601)	(796,783)	(331,495)	61,466	-	-	-	0	8
9															9
10	Ending Balance	$ (3,264,659)	$ (2,864,081)	$ (2,442,858)	$ (2,061,773)	$ (1,676,552)	$ (1,288,601)	$ (796,783)	$ (331,495)	$ 61,466	$ -	$ -	$ -	$ 0	10
11															11
12	Period 13							2022							12
13	Account No. 182-360														13
14	Beginning Balance	(5,727,010)	(5,727,010)	(5,727,010)	(5,727,010)	(5,727,010)	(5,727,010)	(5,727,010)	(5,727,010)	(5,727,010)	(5,727,010)	(5,309,223)	(4,850,976)	(5,727,010)	14
15	Energy Efficiency Program Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	15
16	EEPR Base Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-	16
17	EEPR Amortization Revenue	-	-	-	-	-	-	-	-	-	417,787	458,247	472,677	1,348,711	17
18	Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-	18
19	Subtotal	(5,727,010)	(5,727,010)	(5,727,010)	(5,727,010)	(5,727,010)	(5,727,010)	(5,727,010)	(5,727,010)	(5,727,010)	(5,309,223)	(4,850,976)	(4,378,299)	(4,378,299)	19
20															20
21	Ending Balance	$ (5,727,010)	$ (5,727,010)	$ (5,727,010)	$ (5,727,010)	$ (5,727,010)	$ (5,727,010)	$ (5,727,010)	$ (5,727,010)	$ (5,727,010)	$ (5,309,223)	$ (4,850,976)	$ (4,378,299)	$ (4,378,299)	21
22															22
23															23
24	Period 14							2023							24
25	Account No. 182-360														25
26	Beginning Balance	-	(917,206)	(1,373,589)	(2,097,315)	(2,134,314)	(2,202,425)	(2,393,485)	(2,827,384)	(2,938,378)	(2,735,373)	(2,325,258)	(2,300,532)	-	26
27	Energy Efficiency Program Costs [1]	691,589	728,711	520,179	1,069,155	1,043,363	920,766	1,033,382	1,257,167	1,328,555	1,461,555	1,259,463	2,143,533	13,457,416	27
28	EEPR Base Revenue	(1,259,714)	(1,127,714)	(1,184,783)	(1,049,014)	(1,056,159)	(1,057,645)	(1,413,434)	(1,316,354)	(1,077,174)	(1,068,945)	(1,193,556)	(1,245,429)	(14,049,921)	28
29	EEPR Amortization Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-	29
30	Adjustments [2]	(303,999)	-	-	-	-	-	-	-	-	-	-	-	(303,999)	30
31	Adjustments [3]										61,466			61,466	31
32	Adjustments [4]	11,977	-	-	-	-	-	-	-	-	-	-	-	11,977	32
33	Subtotal	(860,148)	(1,316,209)	(2,038,193)	(2,077,174)	(2,147,111)	(2,339,304)	(2,773,537)	(2,886,571)	(2,686,997)	(2,281,297)	(2,259,351)	(1,402,428)	(823,061)	33
34															34
35	Carrying Charge Period 12	(18,908)	(16,588)	(14,148)	(11,941)	(9,710)	(7,463)	(4,615)	(1,920)	356	-	-	-	(84,937)	35
36	Carrying Charge Period 13	(33,169)	(33,169)	(33,169)	(33,169)	(33,169)	(33,169)	(33,169)	(33,169)	(33,169)	(30,749)	(28,095)	(25,358)	(382,723)	36
37	Carrying Charge Period 14	(4,982)	(7,623)	(11,805)	(12,030)	(12,435)	(13,548)	(16,063)	(16,718)	(15,562)	(13,213)	(13,085)	(8,122)	(145,187)	37
38	Adjustments [4]		-	-	-	-	-	-	-	-	-	-		-	38
39	Subtotal - Carrying Charges	(57,058)	(57,380)	(59,122)	(57,140)	(55,314)	(54,181)	(53,847)	(51,807)	(48,375)	(43,962)	(41,181)	(33,480)	(612,847)	39
40															40
41	Ending Balance	$ (917,206)	$ (1,373,589)	$ (2,097,315)	$ (2,134,314)	$ (2,202,425)	$ (2,393,485)	$ (2,827,384)	$ (2,938,378)	$ (2,735,373)	$ (2,325,258)	$ (2,300,532)	$ (1,435,908)	$ (1,435,908)	41
42															42
43	Total Account 182-360 Balance	(9,908,876)	(9,964,680)	(10,267,183)	(9,923,097)	(9,605,988)	(9,409,095)	(9,351,178)	(8,996,883)	(8,400,917)	(7,634,481)	(7,151,508)	(5,814,207)	(5,814,207)	43
44															44
45	Carrying Charge Rate	6.95%													45
46															46
47	(1) Includes reclass corrections for applicable periods														47
48	(2) 2022 amount recovered in 2022, recorded in 2023														48
49	(3) (Over)/Undercollection from Period 12														49
50	(4) 2023 amounts booked in 2022														50

EXHIBIT K-2

Sierra Pacific Power Company
d/b/a NVEnergy
Energy Efficiency Implementation Balancing Account

Ln	(a)	(b) January	(c) February	(d) March	(e) April	(f) May	(g) June	(h) July	(i) August	(j) September	(k) October	(l) November	(m) December	(n) Total	Ln
1	Period 12							2021							1
2															2
3	Account No. 182-362														3
4	Beginning Balance	$ (239,168)	$ (208,734)	$ (179,863)	$ (151,779)	$ (125,306)	$ (100,679)	$ (75,500)	$ (47,738)	$ (14,775)	$ 14,885	$ -	$ -	$ (239,168)	4
5															5
6	Amortization	30,434	28,870	28,084	26,473	24,627	25,179	27,762	32,963	29,660	-	-	-	254,053	6
7	Adjustments	-	-	-	-	-	-	-	-	-	(14,885) (1)	-	-	(14,885)	7
8	Ending Balance	$ (208,734)	$ (179,863)	$ (151,779)	$ (125,306)	$ (100,679)	$ (75,500)	$ (47,738)	$ (14,775)	$ 14,885	$ -	$ -	$ -	$ -	8
9															9
10	Period 13							2022							10
11															11
12	Account No. 182-364														12
13	Beginning Balance	$ (484,634)	$ (484,634)	$ (484,634)	$ (484,634)	$ (484,634)	$ (484,634)	$ (484,634)	$ (484,634)	$ (484,634)	$ (484,634)	$ (455,655)	$ (419,109)	$ (484,634)	13
14															14
15	Amortization	-	-	-	-	-	-	-	-	-	28,978	36,546	41,814	107,339	15
16	Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-	16
17	Ending Balance	$ (484,634)	$ (484,634)	$ (484,634)	$ (484,634)	$ (484,634)	$ (484,634)	$ (484,634)	$ (484,634)	$ (484,634)	$ (455,655)	$ (419,109)	$ (377,295)	$ (377,295)	17
18															18
19	EEIR Adjustment Period 12							2021							19
20															20
21	Account No. 254-133														21
22	Beginning Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	22
23															23
24	Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	24
25	Adjustments	-	-	-	-	-	-	-	-	-	- (2)	-	-	-	25
26	Ending Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	26
27															27
28	EEIR Adjustment Period 13							2022							28
29															29
30	Account No. 254-135														30
31	Beginning Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	31
32															32
33	Amortization										-	-	-	-	33
34	Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-	34
35	Ending Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	35
36															36
37	Period 14							2023							37
38	Account No. 182-365														38
39	Beginning Balance	$ -	$ 30,222	$ (11,647)	$ (35,190)	$ (94,191)	$ (105,816)	$ (87,059)	$ (110,560)	$ (137,144)	$ (129,578)	$ (89,902)	$ (29,397)	$ -	39
40															40
41	Estimated Savings	95,469	95,491	108,910	98,987	83,359	98,889	96,150	98,948	108,794	114,496	141,329	183,152	1,323,973	41
42	EEIR Base Revenue	(102,495)	(96,880)	(94,321)	(88,116)	(80,425)	(82,051)	(92,137)	(112,083)	(98,605)	(87,641)	(86,603)	(100,306)	(1,121,662)	42
43	Deferral Estimate	(7,026)	(1,389)	14,589	10,871	2,934	16,838	4,013	(13,135)	10,189	26,855	54,726	82,846	202,310	43
44															44
45	Deferral True Up	41,067	(36,587)	(34,036)	(65,894)	(10,658)	5,637	(23,817)	(9,783)	828	1,077	8,362	(34,970)	(158,774)	45
46	Amortizations Booked by Accounting	(0)	-	(229)	76	79	8	6	-	-	-	-	5	(53)	46
47	Adjustments	-	-	-	-	-	-	-	-	-	14,885 (3)	-	-	14,885	47
48	Subtotal to Calculate Carry Charge	34,041	(7,753)	(31,323)	(90,136)	(101,836)	(83,333)	(106,858)	(133,479)	(126,127)	(86,761)	(26,814)	18,485	58,368	48
49															49
50	Carrying Charge P12 182-362	(1,209)	(1,042)	(879)	(726)	(583)	(437)	(276)	(86)	86	-	-	-	(5,152)	50
51	Carrying Charge P13 182-364	(2,807)	(2,807)	(2,807)	(2,807)	(2,807)	(2,807)	(2,807)	(2,807)	(2,807)	(2,639)	(2,427)	(2,185)	(32,513)	51
52	Carrying Charge Current P14 182-365	197	(45)	(181)	(522)	(590)	(483)	(619)	(773)	(730)	(502)	(155)	107	(4,297)	52
53	Carrying Charge Account 254-133	-	-	-	-	-	-	-	-	-	-	-	-	-	53
54	Carrying Charge Account 254-135	-	-	-	-	-	-	-	-	-	-	-	-	-	54
55	Carrying Charge-Adjustment											-		-	55
56	Subtotal	(3,819)	(3,893)	(3,867)	(4,055)	(3,980)	(3,727)	(3,702)	(3,665)	(3,451)	(3,141)	(2,583)	(2,078)	(41,962)	56
57															57
58	Ending Balance	$ 30,222	$ (11,647)	$ (35,190)	$ (94,191)	$ (105,816)	$ (87,059)	$ (110,560)	$ (137,144)	$ (129,578)	$ (89,902)	$ (29,397)	$ 16,407	$ 16,406	58
59															59
60	Total Balancing Account													$ (360,889)	60
61	Carrying Charge Rate	6.95%													61
62															62
63	(1) Reclass 182-362 P12 balance to 182-365 P14 balance		$ 14,885												63
64	(2) Reclass 254-133 P12 balance to 182-365 P14 balance		-												64
65	(3) Total Period 12 Adjustment		$ 14,885												65

Sierra Pacific Power Company
d/b/a NVEnergy
ENERGY EFFICIENCY IMPLEMENTATION BALANCING ACCOUNT

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
Ln		January	February	March	April	May	June	July	August	September	October	November	December	Total	Ln
1	Adjustments per NAC 704.9523.4(a) & (b):							2021							1
2															2
3															3
4	(1) Carry Charge Adjustments														4
5	Period 14 Account No.182-365 Revised Carrying Charges														5
6	Beginning Balance	$ -	$ (4,039)	$ (7,933)	$ (11,917)	$ (15,462)	$ (18,882)	$ (22,246)	$ (25,470)	$ (28,526)	$ (31,428)	$ (19,293)	$ (21,846)	$ -	6
7	Adjustments	(0)	-	(229)	76	79	8	6	-	-	14,885 (3)	-	5	14,832	7
8	Carrying Charge P12 182-362	(1,209)	(1,042)	(879)	(726)	(583)	(437)	(276)	(86)	86	-	-	-	(5,152)	8
9	Carrying Charge P13 182-364	(2,807)	(2,807)	(2,807)	(2,807)	(2,807)	(2,807)	(2,807)	(2,807)	(2,807)	(2,639)	(2,427)	(2,185)	(32,513)	9
10	Carrying Charge Account 254-133	-	-	-	-	-	-	-	-	-	-	-	-	-	10
11	Carrying Charge Account 254-135	-	-	-	-	-	-	-	-	-	-	-	-	-	11
12	Subtotal	(4,016)	(7,887)	(11,848)	(15,373)	(18,773)	(22,118)	(25,323)	(28,362)	(31,247)	(19,182)	(21,720)	(24,026)	(22,833)	12
13															13
14	Carrying Charge P14 Recalculated	(23)	(46)	(69)	(89)	(109)	(128)	(147)	(164)	(181)	(111)	(126)	(139)	(1,332)	14
15															15
16	Ending Balance Adjusted	$ (4,039)	$ (7,933)	$ (11,917)	$ (15,462)	$ (18,882)	$ (22,246)	$ (25,470)	$ (28,526)	$ (31,428)	$ (19,293)	$ (21,846)	$ (24,165)	$ (24,165)	16
17															17
18	Revised Carry Charge Adjustment to Account 229-000														18
19															19
20	As Revised	$ (23)	$ (46)	$ (69)	$ (89)	$ (109)	$ (128)	$ (147)	$ (164)	$ (181)	$ (111)	$ (126)	$ (139)	$ (1,332)	20
21	Recorded	197	(45)	(181)	(522)	(590)	(483)	(619)	(773)	(730)	(502)	(155)	107	(4,297)	21
22	Net Adjustment to Account 229-000	$ (220)	$ (1)	$ 112	$ 433	$ 481	$ 355	$ 472	$ 609	$ 549	$ 391	$ 29	$ (246)	$ 2,965	22
23															23
24	(2) Reclass Revenue														24
25	Period 14 Account No.182-365 to Period 14 Account No.254-136														25
26															26
27	EEIR Base Revenue	$ (102,495)	$ (96,880)	$ (94,321)	$ (88,116)	$ (80,425)	$ (82,051)	$ (92,137)	$ (112,083)	$ (98,605)	$ (87,641)	$ (86,603)	$ (100,306)	$ (1,121,662)	27
28															28
29	(3) Reclass Savings														29
30	Period 14 Account No.182-365 to Account No.229-000														30
31	Beginning Balance													(1,160,902)	31
32	Estimated Savings	$ 95,469	$ 95,491	$ 108,910	$ 98,987	$ 83,359	$ 98,889	$ 96,150	$ 98,948	$ 108,794	$ 114,496	$ 141,329	$ 183,152	$ 1,323,973	32
33	Deferral True Up	41,067	(36,587)	(34,036)	(65,894)	(10,658)	5,637	(23,817)	(9,783)	828	1,077	8,362	(34,970)	(158,774)	33
34	Subtotal	$ 136,536	$ 58,904	$ 74,874	$ 33,093	$ 72,700	$ 104,526	$ 72,332	$ 89,164	$ 109,622	$ 115,574	$ 149,691	$ 148,182	$ 4,297	34
35	Reverse Carrying Charges													(4,297)	35
36	Total													(0)	36
37															37
38	Total Estim Savings and Deferral True Up (2)													$ 1,165,199	38
39															39
40	(4) Carry Charge Calculation On Base Revenue														40
41	Period 14 Account No. 254-136														41
42	Beginning Balance	$ -	$ (103,089)	$ (201,126)	$ (297,159)	$ (387,506)	$ (470,641)	$ (555,892)	$ (651,782)	$ (768,289)	$ (871,915)	$ (965,114)	$ (1,057,808)		42
43	EEIR Base Revenue	(102,495)	(96,880)	(94,321)	(88,116)	(80,425)	(82,051)	(92,137)	(112,083)	(98,605)	(87,641)	(86,603)	(100,306)	$ (1,121,662)	43
44	Subtotal	(102,495)	(199,968)	(295,448)	(385,275)	(467,931)	(552,691)	(648,029)	(763,865)	(866,894)	(959,557)	(1,051,717)	(1,158,113)	(1,121,662)	44
45															45
46	Carrying Charge-Base Revenue Balance	(594)	(1,158)	(1,711)	(2,231)	(2,710)	(3,201)	(3,753)	(4,424)	(5,021)	(5,557)	(6,091)	(6,707)	(43,158)	46
47															47
48	Ending Balance	$ (103,089)	$ (201,126)	$ (297,159)	$ (387,506)	$ (470,641)	$ (555,892)	$ (651,782)	$ (768,289)	$ (871,915)	$ (965,114)	$ (1,057,808)	$ (1,164,820)	$ (1,164,820)	48
49															49
50	Carrying Charge Rate	6.95%													50
51															51
52	(1) Total Period 12 Adjustment														52
53	(2) SPPC did not over earn, amount not to be refunded and is reversed in February														53

EXHIBIT L

NOT APPLICABLE

EXHIBIT M

Sierra Pacific Power Company
Regulatory Return on Equity
As of December 2023
(in thousands)

Ln No	Section	Item No	(a) Descripton	(b) Total Reported	(c) Non Rate-Base	(d) FERC Jurisdiction	(e) Nevada Jurisdiction	Ln No
1	I		**Rate Base**					1
2		1	Utility Plant					2
3		1a	Utility Plant in Service	4,927,207	94,326	421,948	4,410,934	3
4		1b	Electric Plant Held for Future Use	7,681	7,681	—	—	4
5		1c	Capital Leases	119,826	119,826	—	—	5
6		1d	Asset Retirement Obligation	465	465	—	—	6
7		2	Construction Work in Progress	310,309	310,309	—	—	7
8		3	(Less) Accum Prov Depreciation					8
9		3a	Utility Plant in Service	(1,994,918)	(34,719)	(156,295)	(1,803,904)	9
10		3b	Electric Plant Held for Future Use	(1,656)	—	(1,656)	—	10
11		3c	Asset Retirement Obligation	(2,057)	(2,057)	—	—	11
12		4	Other Property and Investments	61,061	61,061	—	—	12
13		5	Working Capital					13
14		5a	Fuel Stock	15,328	—	686	14,642	14
15		5b	Materials and Supplies	83,681	—	7,249	76,432	15
16		5c	Prepayments	14,923	—	1,052	13,871	16
17		5d	Cash Working Capital - Assets	228,752	231,033	(115)	(2,166)	17
18		5e	Cash Working Capital - Liabilities	(295,560)	(295,560)	—	—	18
19		6	(Less) Accumulated Uncollectibles	(2,001)	—	—	(2,001)	19
20		7	Regulatory Assets					20
21		7a	Included in Nevada retail rate base	82,018	—	—	82,018	21
22		7b	Excluded in Nevada retail rate base	61,468	61,468	—	—	22
23		7c	Other recovery method - balancing accounts	207,795	207,795	—	—	23
24		7d	GAAP	29,132	29,132	—	—	24
25		7e	Tax	43,757	5,795	—	37,962	25
26		8	Miscellaneous Deferred Debits					26
27		8a	Included in Nevada retail rate base	55,648	—	3,923	51,725	27
28		8b	Excluded in Nevada retail rate base	3,769	3,769	—	—	28
29		8c	Asset Retirement Obligations	12,596	12,596	—	—	29
30		8d	Other recovery method	—	—	—	—	30
31		8e	Pension - AOCI Adjustment	—	27,029	—	(27,029)	31
32		9	Other Deferred Debits	24,651	24,651	—	—	32
33		10	(Less) Accum Deferred Taxes					33
34		10a	Asset	295,236	20,564	—	274,672	34
35		10b	Liability	(717,439)	(118,534)	(49,231)	(549,674)	35
36		10c	Investment Tax Credit	(654)	(654)	—	—	36
37		11	Obligations Under Capital Leases	(120,301)	(120,301)	—	—	37
38		12	(Less) Reserves	(27,424)	—	(1,993)	(25,431)	38
39		13	Accumulated Provision for Rate Refunds	(812)	(812)	—	—	39
40		14	Derivative Instrument Liabilities	(23,933)	(23,933)	—	—	40
41		15	Asset Retirement Obligations	(11,968)	(11,968)	—	—	41
42		16	(Less) Customer Advances - Constr	(35,618)	—	—	(35,618)	42
43		17	Regulatory Liabilities					43
44		17a	Included in Nevada retail rate base	(15,323)	—	—	(15,323)	44
45		17b	Other recovery method - balancing accounts	(18,722)	(18,722)	—	—	45
46		17c	GAAP	(8,811)	(8,811)	—	—	46
47		17d	Tax	(258,592)	(18,197)	—	(240,395)	47
48		17e	Current year earnings sharing accrual	(114)	(114)	—	—	48
49		18	Other deferred credits	(65,201)	—	—	(65,201)	49
50		19	Unamortized Gain on Reacquired Debt	(101)	(101)	—	—	50
51		20	Long-Term Debt	(1,213,293)	(1,213,293)	—	—	51
52		21	Total Net Utility Rate Base	**1,770,805**	**(650,275)**	**225,568**	**2,195,512**	52
53								53
54	II		**Income Statement**					54
55		25	Operating Revenues	1,474,007	245,164	63,467	1,165,376	55
56		26	Operating Expenses:					56
57		26a	Operations & Maintenance	1,090,178	204,762	44,542	840,787	57
58		26b	Depreciation & Amortization	200,814	20,858	10,499	172,577	58
59		26c	Taxes Other than Income Taxes	30,545	3,234	1,902	25,408	59
60		26d	Income Taxes	11,982	3,756	1,426	6,800	60
61		26e	Investment Tax Credit - Net	628	628	—	—	61
62		26f	Gains/Losses from Disposition of Allowances	(0)	—	—	(0)	62
63		27	Total Operating Expenses	**1,334,147**	**233,238**	**58,370**	**1,045,572**	63
64								64
65		28	Operating Income Before Adjustments	**139,860**	**11,926**	**5,098**	**119,803**	65
66		29	Carry on regulatory assets/liabilities				382	66
67		30	Tracy incentive				(2,349)	67
68		31	Tax on Line 30				493	68
69		32	Net Operating Income				**118,330**	69
70								70
71		33	Other Income	38,206				71
72		34	Other Deductions	(5,939)				72
73		35	Taxes on Other Income and Deductions	(3,921)				73
74		36	Interest Charges	(50,729)				74
75		37	Net Income	**117,477**				75
76								76
77		38	Return on Rate Base (net operating income/adjusted net utility rate base)				**5.39 %**	77

Sierra Pacific Power Company
Regulatory Return on Equity
As of December 2023
(in thousands)

Ln No	III		Cost of Capital (5-quarter average)	Amount (a)	Ratio (b)	Cost % (c)	Weighted Average Cost (d)	Ln No
1		39	Short-Term Debt	10,000	0.30 %	12.82 %	0.04 %	1
2		40	Customer Deposits	19,861	0.60 %	0.09 %	0.00 %	2
3		41	Long Term Debt	1,211,742	36.61 %	4.48 %	1.64 %	3
4		42	Common Equity	2,068,375	62.49 %	9.80 %	6.12 %	4
5		43	Total	**3,309,978**			**7.80 %**	5
6								6
7	**IV**		**Summary**		**Actual**	**Adjustment**	**Allowed**	7
8		44	Operating Income		118,330		171,346	8
9		45	Rate Base		2,195,512	—	2,195,512	9
10		46	Rate of Return (WACC)		5.39 %		7.80 %	10
11		47	Cost of Debt & Preferred		1.68 %		1.68 %	11
12		48	Available for Common		3.71 %		6.12 %	12
13		49	Common Equity Percentage		62.49 %		62.49 %	13
14		50	Imputed Return on Common		**5.94 %**		**9.80 %**	14
15		51	SEC Return on Equity (5-point)	6.63 %				15
16								16
17	**V**		**Earnings Sharing**					17
18			**Sharing Over 9.8% ROE**					18
19		52	Operating Income				118,330	19
20		53	Plus/(less) manual adjustments				—	20
21		54	Plus Long-term incentive plan				921	21
22		55	Tax on Lines 2-3				(193)	22
23		56	Adjusted Operating Income				119,057	23
24		57	Operating Income @ 9.8%				171,346	24
25		58	Difference				(52,289)	25
26		59	50% Sharing				—	26
27		60	Tax Gross Up Factor (21%)				21 %	27
28		61	Tax Gross UP Dollars				—	28
29		62	Sharing Over 9.8% ROE				—	29
30								30

EXHIBIT N

SIERRA PACIFIC POWER COMPANY
d/b/a NV Energy
EXPANDED SOLAR PROGRAM COSTS SUMMARY
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

Exhibit N
Page 1 of 2
Ahlstedt

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
Ln		January	February	March	April	May	June	July	August	September	October	November	December	Summary of Annual Activity	Ln
1															1
2	**PERIOD 1 (2021 Cost Recovery)**														2
3	**Account No. 182-377**														3
4	**Program Costs**														4
5	Beginning Balance	$ 70,958	$ 61,136	$ 52,808	$ 43,634	$ 35,386	$ 26,440	$ 18,158	$ 7,347	$ (2,616)	$ (11,581)	$ -	$ -	$ 70,958	5
6	Revenues	(9,822)	(8,327)	(9,174)	(8,249)	(8,945)	(8,282)	(10,811)	(9,963)	(8,965)	-	-	-	(82,539)	6
7	Adjustments	-	-	-	-	-	-	-	-	-	11,581 (1)	-	-	11,581	7
8	Subtotal Costs	61,136	52,808	43,634	35,386	26,440	18,158	7,347	(2,616)	(11,581)	-	-	-	-	8
9															9
10	**PERIOD 1 (2021 Cost Recovery) Ending Balance**	61,136	52,808	43,634	35,386	26,440	18,158	7,347	(2,616)	(11,581)	-	-	-	-	10
11															11
12	**PERIOD 2 (2022 Cost Recovery)**														12
13	**Account No. 182-377**														13
14	**Program Costs**														14
15	Beginning Balance	$ 133,628	$ 133,628	$ 133,628	$ 133,628	$ 133,628	$ 133,628	$ 133,628	$ 133,628	$ 133,628	$ 133,628	$ 123,990	$ 114,648	$ 133,628	15
16	Revenues	-	-	-	-	-	-	-	-	-	(9,638)	(9,342)	(9,470)	(28,449)	16
17	Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-	17
18	Subtotal Costs	133,628	133,628	133,628	133,628	133,628	133,628	133,628	133,628	133,628	123,990	114,648	105,179	105,179	18
19															19
20															20
21	**PERIOD 2 (2022 Cost Recovery) Ending Balance**	133,628	133,628	133,628	133,628	133,628	133,628	133,628	133,628	133,628	123,990	114,648	105,179	105,179	21
22															22
23	**PERIOD 3 (2023 Cost Recovery)**														23
24	**Account No. 182-377**														24
25	**Program Costs**														25
26	Beginning Balance	$ -	$ 5,074	$ 6,183	$ 7,246	$ 8,267	$ 9,242	$ 10,187	$ 11,063	$ 12,709	$ 17,304	$ 37,077	$ 111,067	$ -	26
27	Program Administration	-	-	-	-	-	-	-	-	-	-	110	-	110	27
28	Program Marketing & Outreach	1,471	-	14,473	-	-	-	-	819	133	25,906	64,813	(15,521)	92,093	28
29	Program Education & Training	-	-	-	-	-	-	-	-	-	-	-	-	-	29
30	Call Center Costs	2,452	-	-	-	-	13	-	-	3,526	4,401	7,768	4,012	22,172	30
31	Web Portal and Application Tools	-	-	-	-	-	-	-	-	-	-	-	-	-	31
32	Application Processing	-	-	-	-	-	-	-	-	132	121	-	51	304	32
33	Adjustments		-	(14,473) (2)	-	-	-	-	-	-	(11,581) (1)	-	-	(26,054)	33
34	Subtotal	3,924	5,074	6,183	7,246	8,267	9,255	10,187	11,882	16,501	36,149	109,768	99,610	88,627	34
35															35
36	Carry Charges Period 1 (3)(4)	354	306	253	205	153	105	43	(15)	(67)	-	-	-	1,336	36
37	Carry Charges Period 2 (3)(4)	774	774	774	774	774	774	774	774	774	718	664	609	8,957	37
38	Carry Charges Period 3 (3)(4)	23	29	36	42	48	54	59	69	96	209	636	577	1,877	38
39	Subtotal - Carrying Charges	1,151	1,109	1,062	1,021	975	933	875	828	802	927	1,300	1,186	12,170	39
40															40
41	Program Costs Balance for Recovery	5,074	6,183	7,246	8,267	9,242	10,187	11,063	12,709	17,304	37,077	111,067	100,796	100,796	41
42															42
43	**PERIOD 3 (Cost Recovery) Ending Balance**	$ 8,998	$ 139,811	$ 140,874	$ 141,895	$ 142,869	$ 143,815	$ 144,691	$ 146,337	$ 150,931	$ 161,067	$ 225,716	$ 205,975	$ 100,796	43
44															44
45	**Total Period 3 Costs for Recovery**	$ 100,796													45
46															46
47	SPPC kWh (Sales)	11,176,745,779													47
48															48
49	Calculated SPPC ESPC Rate	**$ 0.00001**													49

SIERRA PACIFIC POWER COMPANY
d/b/a NV Energy
kWh SALES BILLED AND UNBILLED
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2023

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
Ln	Description	January	February	March	April	May	June	July	August	September	October	November	December	Totals	Ln
1															1
2	Nevada Sales														2
3	Nevada Total (incl IS-2)	740,256,940	664,552,130	697,585,976	635,866,682	651,753,415	659,789,144	838,982,768	791,781,427	664,300,363	623,699,087	678,588,000	700,416,494	8,347,572,426	3
4															4
5															5
6	DOS Sales	251,799,879	182,520,920	233,212,317	209,753,502	268,553,729	192,411,138	266,230,899	231,305,081	246,122,638	252,791,404	251,467,055	243,004,791	2,829,173,353	6
7	Total Subject to ESPC	992,056,819	847,073,050	930,798,293	845,620,184	920,307,144	852,200,282	1,105,213,667	1,023,086,508	910,423,001	876,490,491	930,055,055	943,421,285	**11,176,745,779**	7
8														**To Pg 1, Col (b), Ln 47**	8

JEFFREY R. BOHRMAN

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Sierra Pacific Power Company d/b/a NV Energy (Electric)
Docket No. 24-03___
2024 Deferred Energy Proceeding
Prepared Direct Testimony of

Jeffrey R. Bohrman

1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Jeffrey R. Bohrman. My current position is Director, Regulatory Pricing and Economic Analysis for Sierra Pacific Power Company d/b/a NV Energy ("Sierra" or the "Company") and Nevada Power Company d/b/a NV Energy ("Nevada Power" and, together with Sierra Pacific, the "Companies"). My business address is 6100 Neil Road in Reno, Nevada. I am filing testimony on behalf of Sierra.

2. Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE IN THE UTILITY INDUSTRY.

A. I have been employed by the Companies since May 2005. I have held several positions in the Accounting and Regulatory departments, with the last eight years in the role as a Director/Manager/Supervisor of the Regulatory Pricing and Economic Analysis group. I hold a Bachelor of Science in Business Administration from Humboldt State University in Arcata, California, and a Master of Business Administration degree from Santa Clara University. My statement of qualifications is attached as **Exhibit Bohrman-Direct-1**.

3. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?

A. Yes. I have testified before this Commission a number of times during my 19 years with the Company, most recently in Sierra's 2024 general rate review proceeding (Docket No. 24-02026). A complete list of dockets in which I have provided testimony before this Commission is included with **Exhibit Bohrman-Direct-1**.

4. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY AND HOW IS YOUR TESTIMONY ORGANIZED?

A. The purpose of my testimony is as follows: First, I present an overview of the filing and introduction of other witnesses. Second, I discuss how the procurement of energy and fuel is consistent with the approved Energy Supply Plan ("ESP") and ESP updates, and the processes that the Company has put in place to comply with the applicable ESP or ESP update for transactions that resulted in costs being recorded between January 1, 2023, and December 31, 2023, (the "Deferral Period"). Third, I identify compliance items the Company has satisfied in this filing. Finally, I provide a short conclusion and recommendation to the Commission.

5. Q. ARE YOU SPONSORING ANY EXHIBITS OR APPENDICES?

A. Yes. I am sponsoring the following Exhibit and Technical Appendix:

- **Exhibit Bohrman-Direct-1:** Statement of Qualifications
- **Technical Appendix 3**: A list of ESPs, ESP updates and stipulations that governed transactions that resulted in recorded costs during the Deferral Period.

I. OVERVIEW OF THE FILING

6. Q. WHAT IS THE PURPOSE OF THE APPLICATION?

A. This Application serves several purposes. First, the annual deferred energy filing reports on the Company's implementation of its Commission approved ESP and ESP updates. This requirement is described in Section 704.9482(6) of the Nevada Administrative Code. Second, this Application provides a forum for reviewing the prudence of the transactions reflected in the Company's fuel and purchased power costs and the quarterly base tariff energy rate ("BTER") and deferred energy accounting adjustment ("DEAA") pursuant to Nevada Revised Statutes ("NRS") section § 704.110(11)(d). Third, the Application provides a means for adjusting: 1) the Renewable Energy Program Rate ("REPR"), 2) Temporary Renewable Energy Development ("TRED") trust charge, 3) Energy Efficiency Program Rate ("EEPR"), 4) Energy Efficiency Implementation Rate ("EEIR"), and 5) Expanded Solar Program Costs ("ESPC") rate.

7. Q. PLEASE DESCRIBE THE CONTENTS OF THE FILING.

A. The filing includes an Application, as well as exhibits and schedules, which are described in the Application. The Application also contains the prepared direct testimony of 16 witnesses, including myself. Additionally, the Application contains six Technical Appendices, which contain supporting information, such as the minutes and presentations made to the Risk Committee, and relevant policies. In addition to myself, the following witnesses sponsor the various sections of this Application that they are responsible for managing:

Brian Ahlstedt, Senior Revenue Requirement and FERC Analyst. Mr. Ahlstedt calculates the DEAA balance, the TRED charge, the REPR and the ESPC rate. Mr. Ahlstedt sponsors proposed tariffs, current tariffs and the calculation of rate impacts on the various rate classes. Mr. Ahlstedt also supports the calculations of Sierra's four quarterly BTER and DEAA updates filed with the Commission. Mr. Ahlstedt also sponsors Exhibit A, Exhibit B, Exhibit D, D-1 and D-2, Exhibit G, Exhibit H, Exhibit I and Exhibit N.

Ryan Atkins, Vice President, Resource Optimization. Mr. Atkins describes the Company's risk management and control policies governing the purchase and sale of energy products. Mr. Atkins also identifies the power and fuel transactions, and any financial transactions which occurred during the Deferral Period all of which were made in accordance with strategies and policies that are established by the Risk Committee. Further, Mr. Atkins describes how the Company's gas, power, and gas transportation resources are optimized for the benefit of our retail customers. Finally, Mr. Atkins supports the prudence of the cost of using coal to generate electricity at Sierra's North Valmy Generating Station for the Deferral Period. Mr. Atkins supports Technical Appendix 1.

Catalin Adrian Cacuci, Treasurer. Mr. Cacuci summarizes the Companies' risk control strategies and describes the risk control organization and functions. Mr. Cacuci supports the prudence and reasonableness of recorded fuel and purchase power costs, concluding the transactions that resulted in fuel and purchased power costs recorded during the Deferral Period were conducted in accordance with the Company's corporate governance policies and procedures. Finally, Mr. Cacuci identifies relevant compliance items and reports the status of the Company's efforts to satisfy those directives. Mr. Cacuci supports Technical Appendices 2A, 2B and 2C, as well as Technical Appendix 6.

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

John Lescenski, Manager, Plant Engineering and Technical Services. Mr. Lescenski describes the generating units owned by Sierra that were available to serve its load and support optimization operations for the Deferral Period. He also provides information regarding the Net Capacity Factor and the Equivalent Availability Factor of each unit. Mr. Lescenski further discusses the availability and reliability of the generating fleet, including significant events that restricted the availability of the units. Finally, he discusses costs associated with wear and tear of generating units including a discussion on active Long Term Service Agreements for certain generating units. Mr. Lescenski supports Technical Appendix 5.

Saundra Massic, Director, Customer Contact. Ms. Massic's testimony describes the ESAP and supports the recovery of ESAP costs incurred in the Deferral Period.

Eugene T. Meehan, Special Consultant, National Economic Research Associates. Mr. Meehan examines the prudence of all non-renewable power transactions for terms of less than three years made by Sierra for delivery during the Deferral Period, concluding that the Company acted in a prudent manner and that the costs associated with purchased power transactions are reasonable.

Jenny Naughton Revenue Requirement and FERC Manager. Ms. Naughton supports the calculation of the rate of return and the earnings sharing calculation for Sierra. Additionally, Ms. Naughton supports the calculation of the Amortization EEIR and EEPR rates. Ms. Naughton also sponsors Exhibit F, Exhibits K, K-1, and K-2, Exhibit M, Technical Appendix 4 and Technical Appendix 7.

Edgar Patino, Director of Contract Management and Special Programs. Mr. Patino's testimony addresses: (a) long-term non-renewable power purchase agreements, pursuant to which the Company recorded costs during the Deferral Period; (b) renewable energy and portfolio energy credit purchase agreements, pursuant to which the Company recorded costs during Deferral Period; (c) NV GreenEnergy Rider agreements; and (d) portfolio energy credit replacement costs for several renewable power purchase agreements.

Damon Pettinari, Fuel and Purchase Power Manager. Mr. Pettinari sponsors Exhibit C, which reflects the Company's financial statements, as well as Exhibits E-1 and E-2, which reflect the recorded costs of fuel and purchased power. Mr. Pettinari also explains the Companies' Energy Imbalance Market ("EIM") accounting procedures and protocols and describes and supports the Company's methodology in allocating invoice activity related to the Joint Dispatch Agreement ("JDA"), EIM, and the calculation related to joint saving and transfer payments.

Samantha Prest, Pricing Specialist. Ms. Prest supports the proposed Base EEPR and Base EEIR in this proceeding. Ms. Prest calculates (a) the class and the total revenue requirements associated with the implementation of Energy Efficiency and Conservation ("EE&C") programs, (b) the Base EEIR for each class designed to recover this revenue requirement, and (c) the Base EEPR by class designed to recover projected EE&C program costs. The calculation of the Base EEIR and EEPR can be found in Exhibit J, which is sponsored by Ms. Prest.

Ali Sheikh, Manager, Integrated Energy Services Delivery Operations. Mr. Sheikh supports the reasonableness of the energy efficiency programs ("EEP") costs that are requested for recovery in this case and explains that EEP costs recorded during

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the Deferral Period were necessarily incurred in connection with the delivery of EE&C programs and were reasonable under the circumstances. Mr. Sheikh also sponsors and presents Exhibit J-2, 2024 Forecast Demand Side Management program costs, which provides the Company's estimated program costs for EE&C programs for program year 2024. Exhibit J-2 provides the basis for calculating the Base EEPR and Base EEIR. Mr. Sheikh also supports Nevada Power's cumulative balance in Federal Energy Regulatory Commission Account No. 182.3 for the Deferral Period for the Solar Program, the Lower Income Solar Energy Program, the Wind Program, the Small and Large Energy Storage Programs, and the EV Demonstration Program. Finally, Mr. Sheikh sponsors Exhibit I-2.

Kurt G. Strunk, Managing Director, National Economic Research Associates. Mr. Strunk assesses the reasonableness of the Company's physical natural gas commodity transactions for the Deferral Period. Mr. Strunk concludes that the Company's applied for physical natural gas procurement costs are reasonable and prudent expenditures.

Vernon W. Taylor, Director, Trading Operations. Mr. Taylor describes and supports the Company's optimization of energy supply resources under the JDA. In addition, he also describes and supports the Company's calculation of benefits from EIM transactions for the Deferral Period. Mr. Taylor also supports the Company's forward sales of wholesale electricity. Additionally, he describes and supports the economic dispatch of the Company's generating assets during the Deferral Period. Mr. Taylor describes and supports activities performed as part of the Company's compliance with Commission orders from previous dockets related to wear and tear costs. Finally, Mr. Taylor describes and supports the Company's portfolio optimization of participating resources through active participation in the California Independent System Operator ("CAISO") EIM for the Deferral Period.

Vincent Vitiello, Gas Supply Planning Lead. Mr. Vitiello supports the Company's portfolio of gas transportation assets and associated financial transactions that occurred during the Deferral Period.

Kim Whetzel, Director, Grid Operations and Reliability. Ms. Whetzel explains the procedures that the Company has in place to balance loads and resources, and supports the prudence of those procedures. Ms. Whetzel discusses the Company's participation in the CAISO's EIM and the operational changes as a result of the EIM.

8. Q. WHAT IS THE CUMULATIVE BALANCE IN THE COMPANY'S DEFERRED ENERGY ACCOUNT AS OF DECEMBER 31, 2023?

A. As provided in Exhibit D and sponsored by Mr. Ahlstedt, the cumulative balance in the Company's deferred energy account as of December 31, 2023, is a debit balance of $56,827,863. These balances show a decrease of just under 75 percent from the balance presented in the 2023 proceeding, a decrease that is driven by the significant decline in fuel costs that have materialized. Company witnesses Mr. Atkins, Mr. Meehan, and Mr. Strunk discuss the decreasing costs in the fuel and purchased power markets.

9. Q. WHAT IS THE OVERALL BILL IMPACT OF THIS FILING ON SIERRA'S CUSTOMERS?

A. This filing results in an average bill decrease of 0.55 percent in overall rates, with an average decrease of 0.44 percent (or $0.46 per monthly bill) and 0.62 percent for residential and non-residential customers, respectively. This filing changes public policy charges (i.e., charges that Sierra collects to implement energy policy decisions made by the Nevada Legislature). In this filing, Sierra seeks approval to reset the REPR, the TRED trust charge, the EEPR, the EEIR, and the ESPC rate. These rate components are in place to recover costs expended to administer legislatively mandated public policy programs. Company witnesses, as outlined above, describe in further detail the drivers behind the rate change occurring in each specific public purpose program. This filing does not request a change to Sierra's fuel and purchased power rates or general rates.

10. Q. WHAT IS THE PURPOSE OF THE REPR?

A. The REPR funds cash incentives paid to customers who install renewable private solar generation systems, energy storage systems, and electric vehicle ("EV") infrastructure under the Renewable Energy programs.[1] This cash incentive is paid out to customers that own qualifying renewable energy systems, energy storage systems or EV infrastructure, whether that is an individual or a company (which then may lease the system to someone else). To fund these legislatively mandated REPR cash incentive programs, Sierra is requesting a decrease to the average customer bill of 0.69 percent overall, with an average decrease of 0.58 percent and 0.76 percent for residential and non-residential customers, respectively. Mr. Sheikh provides an overview of the Renewable Generations programs and sponsors the

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[1] *See* NRS Chapter 701B.

REPR amount to be recovered in the Deferral Period. Mr. Ahlstedt sponsors the calculation of the REPR.

11. Q. PLEASE DESCRIBE THE TRED TRUST CHARGE.

A. The Nevada Legislature created the TRED trust to provide financial security to counterparties that were entering into long-term purchase power contracts with the Company to meet the renewable portfolio standard. The Nevada Solar One project, located near Boulder City, is the only purchase power contract that uses the TRED. Nevada Power purchases two-thirds of the output of the facility and Sierra purchases the remaining one-third. To fund the TRED, Sierra is requesting aa decrease in average customer bills from the TRED charge of 0.31 percent for all customers classes, with a proposed decrease of 0.26 percent and 0.35 percent for residential and non-residential customers, respectively. Mr. Ahlstedt sponsors the calculation of the TRED rate.

12. Q. PLEASE DESCRIBE THE EEPR.

A. The EEPR allows the Company to recover the cost of developing and implementing EEP that are designed to help Sierra's customers save energy and reduce their electric bills. Through this filing, Sierra is requesting an increase to overall customer bills from the Base EEPR of 0.01 percent with an average increase of 0.03 percent and a decrease of 0.004 percent for residential and non-residential customers, respectively. Sierra is requesting an increase to overall customer bills from the Amortization EEPR of 0.39 percent, with an average increase of 0.33 percent for residential customers and 0.43 percent for non-residential customers. Mr. Sheikh supports the reasonableness of the EEP costs to be recovered in the Deferral Period, Ms. Prest sponsors the calculation of the EEPR base rates and Ms. Naughton sponsors the amortization rates.

13. Q. PLEASE DESCRIBE THE EEIR.

A. The EEIR is a rate intended to offset negative impacts associated with the successful implementation of EEPs. Through this filing, Sierra is requesting to update the Base EEIR for each class, however in total there is no impact to the average customer's bill for this rate component. Additionally, Sierra is requesting an overall bill increase of 0.05 percent on average from the EEIR amortization rate component. Base EEIR rates are calculated based on approved EE&C budgets, therefore, when Commission-approved budgets increase, the Base EEIR rate would also result in an increase or vice versa if the budgets decreased. Mr. Sheikh sponsors the amount to be recovered in the Deferral Period and Ms. Prest sponsors the calculation of the EEIR base and Ms. Naughton sponsors the amortization rates.

14. Q. PLEASE DESCRIBE THE ESAP RATE.

A. The ESAP is a program that offers certain residential and non-residential customers the opportunity to have their electric consumption be derived from a mix of utility-scale and community based solar resources, without requiring that such customers install physical solar systems on their properties. Through this filing, Sierra is requesting an ESPC rate be set at $0.00001 for all customers which is unchanged from the current ESPC rate. Ms. Massic supports the prudency of the costs incurred for ESAP while Mr. Ahlstedt supports the ESPC rate calculation in this proceeding.

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II. THE PROCUREMENT OF ENERGY AND FUEL IS CONSISTENT WITH THE APPROVED ESP AND ESP UPDATES, AND THE PROCESSES THAT THE COMPANY HAS PUT IN PLACE TO COMPLY WITH THE PLAN

15. Q. HAS THE COMPANY INCLUDED A REVIEW OF THE QUARTERLY RATE ADJUSTMENT APPLICATIONS IN ITS CASE?

A. Yes. Mr. Ahlstedt addresses the quarterly rate adjustment applications in his Prepared Direct Testimony.

16. Q. THE COMPANY PROCURES ENERGY AND FUEL AND OPTIMIZES RESOURCES PURSUANT TO ESP AND ESP UPDATES. DID THE COMMISSION REVIEW THE ESP AND ANNUAL ESP UPDATES UNDER WHICH THE COMPANY OPERATES?

A. Yes, the Company operated pursuant to the Commission approved ESP and ESP updates filed in Docket Nos. 21-06001, 22-09002, and 23-09003. The Company requests that the Commission take administrative notice of these filings and their associated orders and stipulations. The filings and orders are on the Commission's web site. A complete listing of the dockets is contained in Technical Appendix 3.

17. Q. DID THE COMPANY MONITOR THE APPROVED STRATEGIES BASED UPON CHANGING MARKET CONDITIONS THROUGHOUT THE DEFERRAL PERIOD?

A. Yes. During the Deferral Period, the Risk Committee met and received reports showing the effects of the Company's strategies. Mr. Cacuci sponsors the Risk Committee activities during the Deferral Period. The Risk Committee reviewed and approved the strategies filed in the ESP and ESP updates. Furthermore, the Risk Committee reviewed the resource portfolio periodically throughout the Deferral Period. This demonstrates that the approved strategies have been reviewed, deliberated upon, and reassessed during the Deferral Period. Copies of the Risk Committee meeting minutes at which the Company's forward fuel and power positions for the Deferral Period were reviewed, as well as the presentations made to the Risk Committee, are provided as addressed by Mr. Cacuci and are contained in Technical Appendix 6.

18. Q. DID THE COMPANY CONDUCT INFORMATIONAL WORKSHOPS DURING 2023 WITH THE REGULATORY OPERATIONS STAFF ("STAFF") OF THE COMMISSION AND THE NEVADA ATTORNEY GENERAL'S BUREAU OF CONSUMER PROTECTION ("BCP")?

A. Yes. Two workshops were held in 2023 on the following dates: June 29, 2023, and October 10, 2023. Copies of presentations from those workshops are provided in Technical Appendix 1.

III. SIERRA TRACKED AND COMPLIED WITH COMMISSION COMPLIANCE ITEMS AND DIRECTIVES

19. Q. SEVERAL WITNESSES DESCRIBE COMPLIANCE ITEMS AND DIRECTIVES. DOES SIERRA TRACK COMPLIANCE ITEMS AND DIRECTIVES?

A. Yes, the Regulation department tracks compliance items and directives contained in Commission orders. Different organizations throughout the Company are typically responsible for satisfying these regulatory obligations. However, each compliance item that arises from one of the Company's filings is tracked through the Regulation department's SERENA database which is monitored and maintained by the case managers assigned to each docket. Reminder emails of the upcoming due date of compliances are sent from the SERENA database to subject matter experts and/or the assigned case manager at determined intervals. The case

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manager coordinates with the assigned attorney and the subject matter expert(s) to meet the compliance in a timely manner. Sierra had 10 separate compliance items and directives to address in this filing. Mr. Cacuci addresses four[2] and Mr. Taylor[3] two of those items (from several past dockets) in their prepared direct testimonies. Mr. Lescenski addresses two compliance items arising from Docket Nos. 15-03001 and 17-03002 related to the unit operations and maintenance dispatch cost materials. Mr. Ahlstedt confirms that the Company complied with the order from Docket No. 19-03002 and used the recorded costs of purchased fuel or purchased power that are used to adjust the quarterly BTER to also calculate the dead band for the DEAA pursuant to NRS § 704.110(10). Finally, Ms. Naughton addresses the compliance with the Stipulation (dated September 24, 2019) and the Commission's Modified Final Order (dated April 3, 2020) in Docket No. 19-06002.

IV. CONCLUSION

20. Q. PLEASE SUMMARIZE YOUR RECOMMENDATION TO THE COMMISSION.

A. I recommend that the Commission determine the costs recorded in Sierra's deferred energy account during the Deferral Period are reasonable and reflect prudent management decisions. I make this recommendation based on the testimony included in this filing. I also recommend that the Commission reset the public policy rates as set forth in Exhibit A to the filing. Finally, I recommend that the Commission find Sierra has satisfied applicable compliance items and directives as set forth in the prayer for relief contained in Sierra's application.

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[2] Specifically, Mr. Cacuci addresses compliance items from Docket Nos. 05-08004, 06-12001, 10-07003/19-08034 and 11-09004.

[3] Specifically, Mr. Taylor addresses compliance items from Docket Nos. 16-03004 and 17-03002.

21. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

EXHIBIT BOHRMAN-DIRECT-1

JEFFREY R. BOHRMAN
DIRECTOR, REGULATORY PRICING AND ECONOMIC ANALYSIS
RATES AND REGULATORY AFFAIRS
NV Energy
6100 Neil Road
Reno, Nevada 89511-1137

Mr. Bohrman has been an employee of NV Energy for nineteen years, his current position is within the Regulatory Pricing & Economic Analysis section of the Rates & Regulatory Affairs department. His current responsibilities are focused upon electric cost of service and rate design issues and supplementary studies in support of the Rate & Regulatory Affairs department's responsibilities.

Employment History

NV Energy
May 2005 to Present

Director, Regulatory Pricing & Economic Analysis
Manager, Regulatory Pricing & Economic Analysis
Supervisor, Regulatory Pricing & Economic Analysis
Pricing Specialist, Regulatory Pricing & Economic Analysis
Staff Analyst, Regulatory Pricing & Economic Analysis
Senior Analyst, Regulatory Pricing & Economic Analysis
September 2008 to Present

- Guides the Pricing team to resolve the complex set of pricing, financial, economic, and regulatory issues necessary to produce quality filings and the analysis necessary to support management decisions.
- Provides credible and timely cost-of-service studies, rate design and tariff and policy interpretations, develops new pricing and service options that benefit and better serve both the Company and its customers.
- Provides or guides the analysis related to contracts and tariff development as well as supporting a variety of regulatory requirements, including Rule and Tariff administration and interpretation.
- Develops recommendations for objectives and strategies for cost of service and rate design related portions of regulatory filings.
- Provides project direction/management and review for regulatory filings. Coordinates team input and workload.
- Supervises, directs and coordinates analysis and problem resolution related to marginal cost of service, rate design and line extension rules for both Nevada Power and Sierra Pacific Power retail jurisdictions.
- Coordinates with numerous departments to gather data for Marginal Cost of Service, Rate Design Customer Weighting Factor and other Pricing and Economic Analysis Studies.
- Serves as a witness on marginal cost and rate design related matters.
- Provides ancillary support for Company filings and other Rate & Regulatory Affairs department responsibilities.

Senior Accountant, Corporate Accounting
May 2005 to September 2008

<u>Non-NV Energy Employment</u>
Harmonic Inc.
Senior Accountant
January 2000 to May 2005

<u>Prior Testimony before Public Utilities Commission of Nevada</u>
PUCN Docket Nos.: 10-06001, 11-03003, 11-06006, 12-06052, 12-06053, 13-03003, 13-03004, 13-06002, 13-07002, 13-07005, 14-02040, 14-02041, 14-05004, 15-02039, 15-02040, 15-07041, 15-07042, 16-03003, 16-03004, 16-06006, 17-03001, 17-03002, 17-06003, 19-03001, 19-03002, 19-06002, 20-02026, 20-02027, 20-06003, 22-03001, 22-03002, 22-03003, 22-06014, 23-03005, 23-03006, 23-03007, 23-06007, 23-08019, 24-02026

<u>Education</u>
Santa Clara University
Master of Business Administration, December 2003

Humboldt State University
Bachelor of Science in Business Administration, June 1999

Continuing Education
- NARUC Utility Rate School
- NERA Estimation of Electricity Marginal Costs and Application to Pricing
- NERA Marginal Cost Working Group
- Utility Finance and Accounting for Financial Professionals
- Economists Inc. Utilities of the Future Rates Group
- Innovative Rates Working Group

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, JEFF BOHRMAN, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: March 1, 2024

JEFF BOHRMAN

BRIAN AHLSTEDT

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Sierra Pacific Power Company d/b/a NV Energy (Electric)
Docket No. 24-03___
2024 Deferred Energy Proceeding
Prepared Direct Testimony of

Brian Ahlstedt

1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Brian Ahlstedt. My current position is Senior Revenue Requirement & FERC Analyst for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" or the "Company" and, together with Nevada Power, the "Companies"). My business address is 6100 Neil Road Reno, Nevada. I am filing testimony on behalf of Sierra.

2. Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE IN THE UTILITY INDUSTRY.

A. I joined the Companies more than 17 years ago and worked in Fuel and Purchased Power for 11 years and the past six plus years in Regulatory Accounting. Prior to joining the Companies, I spent approximately 15 years in the casino industry working as an analyst, accountant, revenue audit manager and controller. A statement of qualifications is provided as **Exhibit Ahlstedt-Direct-1**.

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and Sierra Pacific Power Company
d/b/a NV Energy

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS SENIOR REVENUE REQUIREMENT AND FERC ANALYST.

A. As Senior Revenue Requirement and FERC Analyst, my responsibilities include calculating the following rates:

- Base Tariff Energy Rate ("BTER"),
- Deferred Energy Accounting Adjustment ("DEAA"),
- Energy Efficiency Program Rate ("EEPR"),
- Temporary Renewable Energy Development ("TRED")
- Renewable Energy Program Rate ("REPR"),
- Expanded Solar Energy Rate ("ESER"),
- Expanded Solar Discount Recovery Rate ("ESDR"), and the
- Expanded Solar Program Costs Rate ("ESPC").

I am responsible for monthly journal entries related to most of the above rates/programs. I also assist on the development of schedules that are related to the Base Tariff General Rate ("BTGR"), and the Natural Disaster Protection Plan ("NDPP").

4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?

A. Yes. I provided testimony in the 2022 and 2023 Annual Deferred Energy Accounting Adjustment filings, Docket No. 22-03002 and Docket No. 23-03006.

5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I support the calculation of the DEAA balance, the TRED rate, the ESPC rates and the REPR. The REPR was initially comprised of six public policy programs:

- Solar Energy Systems Incentive Program ("Solar Program");
- Small Energy Storage Program ("Small Storage Program");
- Large Energy Storage Program ("Large Storage Program"); and
- Electric Vehicle Infrastructure Demonstration Program ("Electric Vehicle Program").

In addition, I support the calculations of Sierra's four quarterly BTERs, DEAAs, and ESER changes filed with the Commission in Docket Nos. 23-05016, 23-08009, 23-11015 and 24-02020.

6. Q. ARE YOU SPONSORING ANY EXHIBITS OR APPENDICES?

A. Yes. I am sponsoring the following Exhibits:

- **Exhibit Ahlstedt-Direct 1** Statement of Qualifications
- **Exhibit A** Proposed Tariffs
- **Exhibit B** Current Tariffs
- **Exhibit D** Summary of the DEAA Balance
- **Exhibit G** Summary of Proposed and Present Rates
- **Exhibit H** Determination of TRED Rate
- **Exhibit I** Calculation of REPR
- **Exhibit N** Calculation of ESPC

7. Q. PLEASE DESCRIBE EXHIBITS A AND B.

A. **Exhibit A** consists of tariffs showing the TRED, REPR, EEPR, EEIR, and ESPC rates proposed in this Application. **Exhibit B** consists of the currently effective tariffs. These exhibits are filed in compliance with NAC § 703.2211.

8. Q. PLEASE DESCRIBE EXHIBITS D, D-1, AND D-2.

A. **Exhibit D** is a summary of the deferred energy account and shows the cumulative balance at the end of the calendar year 2023 (the "Deferral Period"). Pursuant to the Commission's order in Docket No. 11-07012, Sierra's Electric DEAAs have been updated quarterly since January 1, 2012. Therefore, no changes to the DEAA have been filed in this Application. Likewise, the BTER also changes quarterly. Therefore, this Application does not propose a change to the BTER.

Exhibit D-1 provides a synopsis of monthly activity in the deferred energy balancing account since December 31, 2022, the end of the deferral period in Sierra's last DEAA application, Docket No. 23-03006. **Exhibit D-1** shows the monthly deferrals, the calculation of carrying charges, and any adjustments to the balancing account including all adjustments made in compliance with the Commission's order in the above referenced Docket No. 11-07012.

Exhibit D-2 shows the recorded monthly kWh sales (billed and unbilled) for the Deferral Period categorized by Nevada, Federal Energy Regulatory Commission ("FERC) jurisdictions and off-system sales. Nevada sales are further detailed between interruptible irrigation (IS-2) and all other sales.

9. Q. HAVE YOU REFLECTED ANY ADJUSTMENTS TO THE RECORDED BALANCE PRESENTED IN EXHIBIT D?

A. No.

10. Q. HAVE YOU PROVIDED AN UPDATE OF THE TRED RATE ELEMENTS?

A. Yes. The proposed TRED rate for this filing is \$0.00032, a decrease from the current TRED rate of \$0.00072. The TRED rate shown in **Exhibit H** is based on the total funding required for the year that the rate will be in effect, from October 1, 2024, through September 30, 2025.

Total funding requirements are calculated by forecasting total receipts (including interest income) and disbursements to the trust, plus the minimum balance requirement, less the projected balance at September 30, 2024. The funding requirement is then divided by historical sales (**Exhibit H-1**). Work papers detailing the calculation of monthly receipts and disbursements are provided as part of this filing.

There is no projected funding requirement from Sierra. During 2023, no additional funding was required for the Sierra TRED account.

11. Q. HAS THE COMPANY PROVIDED A REVISED REPR COMPONENT RATE?

A. Yes. Consistent with the regulations adopted by the Commission in Docket No. 07-06026, Sierra has calculated two-part rates for the existing Solar Program. Additionally, in compliance with Senate Bill 145 ("SB145") as described in the 2021

Annual Clean Energy Annual Plan, Docket No. 20-01040, the Company has provided two-part rates for the remaining REPR programs.

Each of the applicable program regulations calls for a prospective rate determined by dividing projected program costs by projected kWh for the program year. The program year is defined as July 1 through June 30. The regulations additionally provide for a clearing rate which is calculated by dividing the cumulative balance in the applicable subaccount of FERC Account No. 182.3 at the end of the deferred energy test period by the appropriate test period sales. The calculation of rates for Solar, Small Energy Storage, Large Energy Storage, and Electric Vehicle programs are shown on **Exhibit I**, pages 1 and 2 of 3.

Part (a) of each rate utilizes the projected program costs, shown on **Exhibit Sheikh-Direct-I-2**, divided by projected sales for the program year July 1, 2024, through June 30, 2025, shown on **Exhibit I**, page 3 of 3. Part (b) divides the applicable regulatory asset cumulative balance shown in **Exhibit Sheikh-Direct-7A, 8A, 9A, 10A**, (Account No. 182.3) by calendar year 2023 sales from **Exhibit I-1**. The prepared direct testimony of Mr. Ali Sheikh supports the prudence of existing Solar, Small Energy Storage, Large Energy Storage, and Electric Vehicle program balances as well as the future cost projections.

The proposed Solar, Small Energy Storage, Large Energy Storage and Electric Vehicle programs' rates are combined on the Statement of Rates into a single component identified as REPR. **Table Ahlstedt-Direct-1** below reflects the proposed REPR of $0.00089 which is a decrease of $0.00088 from the current

REPR charge of $0.00177. The present and proposed rate components of the REPR are as follows:

Table Ahlstedt Direct 1 Present and Proposed REPR Rates						
	Part (a)		Part (b)		Total	
	Present	Proposed	Present	Proposed	Present	Proposed
Solar	0.00003	0.00000	0.00133	0.00044	0.00136	0.00044
Small Energy Storage	0.00006	0.00002	(0.00009)	(0.00008)	(0.00003)	(0.00006)
Large Energy Storage	0.00004	0.00007	(0.00001)	(0.00001)	0.00003	0.00006
Electric Vehicle	0.00040	0.00013	0.00001	0.00032	0.00041	0.00045
Total	0.00053	0.00022	0.00124	0.00067	0.00177	0.00089

12. Q. PLEASE DESCRIBE EXHIBIT G.

A. **Exhibit G** is a 15-page document that shows by component, and in total, the impact of the rate changes requested in this application. These pages are described here and the changes shown in the **Table Ahlstedt-Direct-2** following.

- Page 1 provides a summary of all present and proposed rate revenue.
- Pages 2 through 4 summarize present rate BTGR, BTER and DEAA revenue. None of these rate components change as a result of this filing.
- Page 5 summarizes present and proposed REPR revenue.
- Pages 6 and 7 summarize the impact of the prospective Base and Amortization EEPR revenue.
- Pages 8, 9 and 10 summarize the impact of the prospective Base, Amortization, and Adjustment EEIR revenue.
- Page 11 summarizes the impact of the change in the NDPP rate, but no rate components change as a result of this filing.
- Page 12 summarizes the impact of the change in the TRED rate.
- Page 13 summarizes the impact of the change in the ESPC rate.

- Page 14 summarizes the impact of the change in the ESDR rate, but no rate components change as a result of this filing.
- Page 15 shows the impact of the total changes on the typical bill for Schedule No. D-1 and Schedule No. DM-1 customers.

The percentage changes in these schedules are shown below in **Table Ahlstedt-Direct-2**.

Table Ahlstedt Direct-2			
Proposed Rate Revenues Increase (Decrease)			
			Overall
Pg 1-Summary			(0.55)%
Pg 2-BTGR	>		
Pg 3-BTER	> no change as a result of this filing		
Pg 4-DEAA	>		
Pg 5-REPR			(0.69)%
Pg 6-EEPR Base			0.01 %
Pg 7-EEPR Amort			0.39 %
Pg 8-EEIR Base			- %
Pg 9-EEIR Amort			0.05 %
Pg 10-EEIR Adj			- %
Pg 11-NDPP	> no change as a result of this filing		
Pg 12-TRED			(0.31)%
Pg 13-ESPC			- %
Pg 14-ESDR	> no change as a result of this filing		
Pg 15-Typical Bill - Res Single-Family			(0.43)%
Pg 15-Typical Bill - Res Multi-unit Complex			(0.43)%

13. Q. PLEASE DESCRIBE EXHIBIT N.

A. **Exhibit N** provides an overview of the calculation of the ESPC rate reflecting the period ending December 31, 2023. This calculation is consistent with Section 16 of the regulations adopted by the Commission in Docket No. 19-06028. Carrying charges are recorded as described in the order from Docket No. 20-12003[1]. For that reason, costs are reflected for 2023 as Period 3 costs and costs being amortized from January through September 2023 in current rates are reflected as Period 2 to properly calculate carrying charges. This illustration is similar to the balancing account treatment the Companies use for other programs' costs and recovery. This methodology ensures that any over or under collection is tracked and reclassified, as necessary. The prepared Direct testimony of Saundra Massic supports the prudency of costs during the Deferral Period.

Page two shows the test period sales for the 12 months ending December 31, 2023. The total is reflected on page one. The rate is calculated by dividing the cumulative balance for Period 2 by the total test period sales for all applicable customers, including Distribution Only Sales ("DOS") customers.

14. Q. WHAT IS THE RESULT OF THE RATE CALCULATION IN EXHIBIT N?

A. The calculation in **Exhibit N** results in a rate of $0.00001, which is no change from the current rate of $0.00001.

[1] Docket No. 20-12003, August 11, 2021, Order at 104, paragraph 280.

15. Q. HAS THE COMPANY PROVIDED INFORMATION REGARDING ITS QUARTERLY BTER ADJUSTMENTS AS REQUIRED BY NRS § 704.110(11)(d)?

A. Yes. NRS § 704.110(11)(d) provides that:

> The proceeding regarding the annual deferred energy accounting adjustment application must include a review of each quarterly rate adjustment and the transactions and recorded costs of purchased fuel and purchased power included in each quarterly filing and the annual deferred energy accounting adjustment application.

During the Deferral Period, Sierra made four quarterly rate adjustment applications based on monthly costs. **Table Ahlstedt-Direct-3**, below, provides the docket number for each quarterly adjustment, the applicable test period, and a reference to the docket(s) in which test period costs have been reviewed by the Commission. All the recorded costs were either reviewed in Sierra's previous deferred energy cases or are being presented for review in this application.

Table Ahlstedt-Direct-3
Quarterly BTERs

Quarterly BTER Adjustment	Test Period for Quarterly BTER Adjustment	Test Period Costs Previously Reviewed
Docket No. 23-02018	12 Months Ended December 31, 2022	Docket No. 23-03006 (1st, 2nd, 3rd, 4th Qtr. 2022)
Docket No. 23-05016	12 Months Ended March 31, 2023	Docket No. 23-03006 (2nd, 3rd, 4th Qtr. 2022)
Docket No. 23-08009	12 Months Ended June 30, 2023	Docket No. 23-03006 (3rd & 4th Qtr. 2022)
Docket No. 23-11015	12 Months Ended September 30, 2023	Docket No. 23-03006 (4th Qtr. 2022)

Each of the quarterly BTER adjustment filings included a change to the DEAA. In this Application, purchased fuel and power transactions for the Deferral Period are shown on **Exhibit E** sponsored by Damon Pettinari. This includes all transactions associated with the quarterly BTER adjustments that were filed and became effective in 2023, as well as all transactions included in the quarterly adjustment filed on February 15, 2024, based on the calendar year 2023 (Docket No. 24-02020). The Company filed an application in Docket No. 23-05029 to adjust the DEAA in excess of the maximum allowable adjustment under NRS § 704.110(10) to provide a discounted rate effective July 1, 2023. The Commission accepted the application as modified by a Stipulation between the Company, the Regulatory Operations Staff and the Bureau of Consumer Protection. Jenny Naughton provides additional details regarding the deviation in her testimony.

16. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

EXHIBIT AHLSTEDT-DIRECT-1

Statement of Qualifications
for
Brian D Ahlstedt

Summary of Qualifications

Seventeen years of regulatory, accounting and utility experience. Experience in regulatory and operations accounting areas. Knowledge of regulatory activities and regulatory accounting for NV Energy's Nevada jurisdictions.

Professional Experience

Senior Revenue Requirement and FERC Analyst, Revenue Requirement and Regulatory Accounting
Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy
Nov 2017 - Present

Responsible for regulatory filings, tariff development, Nevada deferred energy filings, revenue requirement calculations and various aspects related to general rate case filings.

Business Analyst Accounting, Fuel and Purchased Power Accounting
Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy
July 2006 – Nov 2017

Responsible for the preparation of journal entries related to the costs of fuel and purchased power. Settlements of purchases and sales of fuel and purchased power, transportation expenses, etc. Also prepared parts of FERC Form 1 and 557. Prepared accounting portion of the TRED.

Revenue Audit Manager, Peppermill Reno
March 2006 – July 2006

Responsible for overseeing a staff of 12. Department was responsible for verifying all sales and revenues for every area of the property such as, slot machines, bars, restaurants, hotel, etc.

Controller, Holder Hospitality, Truck Inn Fernley NV.
Dec 2005 – March 2006

Responsible for all aspects of accounting, accounts payable, payroll, accounts receivable, etc. with a direct report staff of 5.

Controller, Loper Enterprises
May 2005 - Oct 2005

Responsible for all aspects of accounting, accounts payable, accounts receivable, payroll, etc. for six convenience stores and a small casino. Managed a staff of up to 15 people.

Controller, Bordertown Casino
May 2003 - May 2005

Responsible for all aspects of accounting, accounts payable, accounts receivable, payroll, etc. for a small casino, convenience store, liquor store, and RV park. Managed a staff of 4 people.

Accountant, Reno Hilton
2001 – May 2003

Responsible for booking all kinds of revenues, expenses and statistical data. Assisted in the implementation a new fixed asset program for the property.

Financial Analyst, Circus Circus Reno
1998 - 2002

Responsible for compiling all departmental budgets into one document, market comparisons and other as needed projects.

Dealer, Various casinos in northern Nevada
1993 - 2001

Responsible for dealing Blackjack, Roulette, Poker Pai Gow, etc. and providing customer service.

Education

University of Nevada, Reno
Bachelor of Science in Gaming Management Dec 1998

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, BRIAN AHLSTEDT, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: March 1, 2024

BRIAN AHLSTEDT

RYAN ATKINS

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Sierra Pacific Power Company d/b/a NV Energy (Electric)
Docket No. 24-03___
2024 Deferred Energy Proceeding
Prepared Direct Testimony of

Ryan Atkins

1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS, AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Ryan Atkins. I am the Vice President, Resource Optimization for Sierra Pacific Power Company d/b/a NV Energy ("Sierra" or the "Company") and Nevada Power Company d/b/a NV Energy ("Nevada Power" and, together with Sierra, the "Companies"). I work primarily out of Nevada Power's office at 6226 West Sahara Avenue, Las Vegas, Nevada. I am filing testimony on behalf of Sierra.

2. Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE IN THE UTILITY INDUSTRY.

A. My experience includes more than 16 years in the energy sector with positions in a number of areas including power trading, gas trading, analytics, and planning. For the past three years, I have been in various leadership roles overseeing the Companies' activities related to energy trading and origination, market operations, and integrated resource planning.

My statement of qualifications is attached as **Exhibit Atkins-Direct-1**.

3. Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. My current responsibilities involve the oversight of the Resource Optimization and Resource Planning teams. These teams are responsible for a number of activities including, but not limited to, development of the Companies' Integrated Resource Plans ("IRP"), development of the Companies' Energy Supply Plans ("ESP") and ESP updates, development of the Companies' Gas Information Reports, all power and natural gas trading activities, coal procurement, short and long term production cost modeling, the development of trading analytics to support energy marketing and origination activities, participation in the Western Energy Imbalance Market, and wholesale market development and design efforts.

4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?

A. Yes. I have previously testified before the Commission in deferred energy proceedings, ESP filings, and IRP filings. Most recently I filed testimony in the Companies' Fifth Amendment to the 2021 Joint IRP, Docket No. 23-08015.

5. Q. ARE YOU SPONSORING ANY EXHIBITS OR APPENDICES?

A. Yes. I am sponsoring the following exhibits and technical appendix to my prepared direct testimony:

Exhibit Atkins-Direct-1	Statement of Qualifications
Exhibit Atkins-Direct-2	Power Procedures Manual
Exhibit Atkins-Direct-3	Natural Gas Procedures Manual
Exhibit Atkins-Direct-4	Forward Power Sales Procedures Manual
Exhibit Atkins-Direct-5	Power Transactions
Exhibit Atkins-Direct-6	Physical Gas Request for Proposals
Exhibit Atkins–Direct-7	Physical Gas Transactions
Exhibit Atkins-Direct-8	Physical Power Request for Proposals
Technical Appendix 1	Gas Hedge Workshop Materials

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

6. Q. PLEASE IDENTIFY SOME OF THE MANUALS THAT THE COMPANY HAS ADOPTED TO GUIDE THE PURCHASE AND SALE OF ENERGY PRODUCTS.

A. The Power Procedures Manual covers all transactions involving physical or financial power products, with the exception of renewable energy products. The Power Procedures Manual promotes the efficient and accurate processing of power transactions, the effective preparation and distribution of information relating to those activities, and the effective management of those activities. The Power Procedures Manual in effect during the deferral period, January 1, 2023 through December 31, 2023 ("Deferral Period") is provided in **Exhibit Atkins-Direct-2**.

The Natural Gas Procedures Manual covers all transactions involving physical and financial gas. Similar to the Power Procedures Manual, the Natural Gas Procedures Manual enumerates procedures designed to promote the efficient and accurate processing of natural gas transactions, the effective preparation and distribution of information relating to those trading activities, and the effective management of those trading activities. The Natural Gas Procedures Manual in effect during the Deferral Period is provided in **Exhibit Atkins-Direct-3**.

The Forward Power Sales Procedures Manual outlines the organization, governance, processes, and procedures that apply to a specific subset of power transactions. Specifically, the Forward Power Sales Procedures Manual covers intermediate and long-term (i.e., one month or more) power sale transactions. The Forward Power Sales Procedures Manual in effect during the Deferral Period is provided in **Exhibit Atkins-Direct-4**.

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

7. Q. DID THE COMPANY FOLLOW THE GOVERNING PROCEDURES DURING THE DEFERRAL PERIOD?

A. Yes. The Company followed a Commission-approved ESP, approved ESP updates, and supplemental and additional ESP updates,[1] and appropriate procedures and policies during the Deferral Period. As explained in more detail below, the Company used the resources (e.g., fuel, power purchases and generating units) available to it in an appropriate and efficient manner to meet its load responsibility during the Deferral Period.

8. Q. WHAT RESOURCES WERE AVAILABLE TO SIERRA TO PROVIDE ELECTRIC SERVICE TO ITS CUSTOMERS DURING THE DEFERRAL PERIOD?

A. John Lescenski's Prepared Direct Testimony discusses the generating resources that were available to Sierra during the Deferral Period.

Vincent Vitiello's Prepared Direct Testimony discusses the gas transportation capacity that was available to Sierra during the Deferral Period.

Edgar Patino's Prepared Direct Testimony identifies renewable and non-renewable power purchase agreements ("PPAs") that supplied energy to the Company.

Vernon Taylor's Prepared Direct Testimony describes Sierra's optimization of power supply resources pursuant to a Joint Dispatch Agreement, as well as the Company's assessment of energy imbalance market ("EIM") transactional benefits, portfolio optimization of participating resources in the EIM, forward sales

[1] *See* Docket Nos. 21-04036, 21-06001, 22-09002, and 23-09003.

transactions, and the economic dispatch of the Company's generating assets during the Deferral Period.

My Prepared Direct Testimony describes Sierra's physical and financial gas procurement activities, forward physical power procurement activities, the results of requests for proposals ("RFP") for various products consistent with the governing ESP, ESP updates and supplemental and additional ESP updates, and the results of any intermediate-term power purchases for the Deferral Period.

9. Q. WHAT WERE THE POWER MARKET CONDITIONS IN THE WESTERN UNITED STATES DURING THE DEFERRAL PERIOD?

A. As noted in recent filings, western energy markets have continued to experience rapid and significant changes in climate, weather, resource, policy, and energy consumption patterns. This has led to continued upward pressure on market power prices in the summer months. Rapidly growing loads throughout the region continued to strain the electric grid, especially during 'net peak' hours, or the time when renewable resources were producing at minimal levels. This was especially prevalent in the Desert Southwest where extreme solar ramps occur as the sun sets and loads remain elevated. Coal supply and delivery remained a challenge for the entire region as demand for coal remained elevated while coal mines and railroads remained strained to catch up to production and transportation needs. Supply chain disruptions and labor shortages also continued and led to delays in new resource additions throughout the west. While the state of California experienced record rainfall, the Pacific Northwest saw reservoir levels well below normal leading to less available hydroelectric power from the region during the summer months.[2] In summer, the combination of record temperatures, high loads, low water levels in the Pacific Northwest, reduced coal supply, increased gas prices, and uncertainty surrounding the California Independent System Operator ("CAISO") market rules, all contributed to limited supply and high purchased power prices throughout the west during the Deferral Period.

10. Q. DID THE REGION EXPERIENCE HIGHER THAN NORMAL TEMPERATURES AND LOADS DURING THE DEFERRAL PERIOD?

A. Yes. Nevada saw extreme weather conditions in summer 2023 with the coolest June on record but also the hottest July on record. In fact, July 2023 was the hottest month ever recorded in Las Vegas as temperatures reached 110 degrees or higher on 17 different days. The Companies saw their seventh highest peak load ever when load reached 8,135 megawatts on July 21. The Companies also experienced three other days in July with peak loads that were in the 10th highest loads in Company history. Phoenix, Arizona also experienced record-breaking conditions as it experienced the hottest single month of any U.S. city on record in July. That included 31 straight days with temperatures of 110 degrees or higher. In addition, 20 other major cities in the United States experienced their hottest summers ever, and the summer was the Earth's hottest since global records began in 1880, according to scientists from NASA.[3] These unprecedented temperature levels continue to underscore the extreme conditions the Company must be prepared for in order to provide safe and reliable service to our customers.

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[2] *US Pacific Northwest water supplies fall to 22-year low in 2023*, Reuters (October 3, 2023), https://www.reuters.com/business/energy/us-pacific-northwest-water-supplies-fall-22-year-low-2023-2023-10-03/#:~:text=Lack%20of%20water%20in%202023,103%25%20of%20normal%20in%202022.

[3] https://www.nasa.gov/news-release/nasa-announces-summer-2023-hottest-on-record/

11. Q. DID THE COMPANY HAVE CONCERNS REGARDING RESOURCE ADEQUACY LEADING INTO AND DURING THE DEFERRAL PERIOD?

A. Yes. Resource adequacy has been an increasingly important focus of the Companies over the past several years. As western energy markets continue to rapidly evolve, the Company and stakeholders have had to reevaluate established practices, in particular large reliance on market purchases, to ensure sufficient capacity to meet peak demands during the summer. While the Company has taken great strides in recent filings to address the variability of renewable resources and their contribution to resource adequacy by updating the Effective Load Carrying Capability ("ELCC") and Planning Reserve margin ("PRM"), addressing changes in weather through the use of new trended weather load forecasts, and taking steps regarding concerns about market availability, the concern and focus remain on the uncertain availability and deliverability of market capacity and energy.

As described in both the Fourth and Fifth amendments to the 2021 Joint IRP, these risks had manifested themselves for three straight summers heading into the Deferral Period as extreme climate related incidents no longer appear to be isolated events. While previously described in the Fourth Amendment, the following events that impacted the Companies in the summers of 2020, 2021, and 2022 bear repeating.

In August of 2020, the western United States experienced an extreme and prolonged heatwave that resulted in record loads and, ultimately, rolling blackouts for CAISO. On August 18, 2020, due to the strain across the entirety of the Western Interconnection, the Companies experienced significant supply curtailments due to the extreme conditions with the largest curtailment occurring in hour ending 19 with curtailments of 1,243 MW. This led to the Companies entering a Level 3

Energy Emergency Alert ("EEA"), which is the highest level of emergency and means load shed is imminent.

In July of 2021, the Companies experienced a similar event. On July 9, 2021, the Companies again experienced an EEA Level 3 event when a wildfire in southern Oregon resulted in the instantaneous reduction of approximately 5,500 MW of transmission capacity on the two most critical transmission lines flowing power from the Pacific Northwest to the Desert Southwest. The Companies' total curtailment was 1,406 MW and trading staff took every available action to procure replacement supply to maintain resource adequacy. This EEA event occurred on the same day on which Nevada and many other western states experienced near record breaking temperatures causing high demand throughout the entire western interconnection. On this date, the Companies set a new combined system peak load record of 8,384 MW.

Another west-wide heat wave took place in September of 2022 as the first week of the month proved to be one of the most challenging periods on record for the western electrical grid. Given the intensity and duration of the event, this heat event ranked as one of the worst heatwaves in the past 40 years for the western United States. Temperature records were broken in major cities throughout the west including San Francisco, Salt Lake City, Billings, Boise, Reno, Las Vegas, and Sacramento. The Companies exceeded their previous all-time September peak six different times with a new record peak for the month of September of 7,752 MW (previous peak was 7,304 MW set in 2021). September 6 in particular was extremely challenging for nearly all western entities. On this day, CAISO peaked at 52,061 MW, a new record, and narrowly avoided rolling blackouts. In addition, the Western Electricity Coordinating Council ("WECC") peaked at 167,499 MW which was also a new record. On the evening of September 6, six entities issued some level of EEA including CAISO, Idaho Power, and the Western Area Lower Colorado Balancing Authority, who all issued Level 3 EAAs as energy in the market was limited and prices reached as high as $1,900/MWh.

12. Q. IS THERE SUPPORTING INFORMATION THAT JUSTIFIES THE COMPANIES' CONCERNS RELATED TO RESOURCE ADEQUACY IN THE WEST?

A. Yes. Major organizations such as the North American Electric Reliability Corporation ("NERC"), WECC, and Energy and Environmental Economics ("E3") have all published reports focused on resource adequacy that have highlighted the risks in the western United States.

In February 2022, E3 published a study titled Resource Adequacy in the Desert Southwest. In the report, E3 highlighted that "[s]ubstantial reliability risks remain as the region's electricity resource portfolio transitions, most notably: weather- and climate-related uncertainties, performance of battery storage, and risks related to the timing of new additions…."[4] Additionally, the report stated that "load growth and resource retirements are creating a significant and urgent need for new resources in the Southwest region; maintaining regional reliability will hinge on whether utilities can add new resources quickly enough to meet this growing need and will require a pace of development largely unprecedented for the region…."[5]

[4] E3, Resource Adequacy in the Desert Southwest, February 2022, p. 1, https://www.ethree.com/wp-content/uploads/2022/02/E3_SW_Resource_Adequacy_Final_Report_FINAL.pdf.
[5] *Id.*

In November 2022, WECC released its 2022 Western Assessment of Resource Adequacy report (“WARA Report”). In the WARA Report, WECC stated:

> The West is experiencing rapid and significant changes in climate, weather, policy, energy consumption patterns, and technology that are challenging the industry’s ability to reliably operate and maintain the grid. These changes, coupled with a rapidly transforming resource mix and push for electrification, create risks that will continue to grow over the next decade. These changes are affecting resource adequacy today and are expected to have increasing impacts in future years. There is an urgent need for the West to address resource adequacy issues now.[6]

In December of 2022, NERC released its 2022 Long-Term Reliability Assessment report (“LTRA Report”). This LTRA Report echoed the same sentiments that were published by E3 and WECC. In evaluating the western United States, the NERC report states:

> As solar decreases as sunset approaches, the total of all available resources can fall short of the demand” and “[i]mports are limited and cannot satisfy the increased demand levels….”[7] The report goes on to discuss the challenges associated with the net peak hours when solar generation starts to dop off: “late summer periods in the Southwest have the greatest risk of energy shortfalls due to the hot temperatures and potential for volatile electricity demand along with drop-off in solar that begins to occur earlier each day.[8]

Late in the Deferral Period, new reliability assessment reports were published by both NERC and WECC. The Company believes it is important to highlight the continued concerns that are published by these reliability entities to alert the Commission and all stakeholders to the risks that exist for the state of Nevada.

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[6] WECC, Western Assessment of Resource Adequacy, 2022, p. 2, https://www.wecc.org/Reliability/2022%20Western%20Assessment%20of%20Resource%20Adequacy.pdf.
[7] NERC, 2022 Long-Term Reliability Assessment, December 2022, p. 11, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.
[8] *Id.*

In November 2023, WECC released its updated WARA report. This report highlights that resource adequacy risk has grown since its previous reports, "Resource adequacy remains a critical risk in the Western Interconnection and continues to challenge industry planners, operators, regulators, and partners. Resource adequacy risks over the medium and long term have increased significantly compared to last year's assessment."[9] A number of factors contribute to the increasing resource adequacy concerns, including the retirement of thermal generation, greater reliance on variable resources, which may not be available during peak hours without storage, and continued load growth on the system. All these factors are present in Nevada.

In December 2023, NERC released its updated LTRA report. The report labels the entire Western Region as an "Elevated Risk" area which means "they may face challenges meeting load under extreme conditions."[10]

Ultimately, these organizations continue to issue resource adequacy cautionary statements regarding uncertain availability and deliverability of market capacity and energy. The findings from all of these reports highlight the energy supply concerns in the western United States, and highlight why the Company is so focused on resource adequacy and the Company's multiple strategies to ensure reliable energy supply to its customers by continuing to proactively purchase energy supply in advance through its laddering process, identifying non-CAISO supply, and paying elevated prices when needed to support reliability for Nevada customers.

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[9] WECC, Western Assessment of Resource Adequacy, 2023, p. 2, https://www.wecc.org/Administrative/2023%20Western%20Assessment%20of%20Resource%20Adequacy.pdf.

[10] NERC, 2022 Long-Term Reliability Assessment, December 2022, p. 7, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

13. Q. WHAT ARE THE SPECIFIC RISKS AND WHAT SHOULD THE COMMISSION BE CONCERNED ABOUT WITH RESPECT TO RESOURCE ADEQUACY?

A. The consequences of failing to prioritize resource adequacy are serious, including having the Company's customers without critical energy resources on peak summer days. A 2023 study published by Environmental Science & Technology evaluated the potential impacts on safety and health resulting from a multi-day blackout event in Arizona. The study found that if a multi-day heat wave and grid failure occurred simultaneously in the Phoenix area, more than 13,000 people would die.[11] While this is an extreme example, it highlights that energy service is more than merely a service of convenience, this is a life-safety service that we collectively cannot allow to fail.

14. Q. DID THE COMPANY CONTINUE TO HAVE A LARGE OPEN CAPACITY POSITION DURING THE DEFERRAL PERIOD?

A. Yes. Nevada continued to be in a position of overreliance on energy resources outside of Nevada. As discussed in Q&A 11 regarding resource adequacy, the Company has worked to address the variability of renewable resources by updating the ELCC and PRM and addressed changes in weather through the use of new trended weather load forecasts. These were Commission-approved changes implemented to the Companies' long-term planning to better reflect the open capacity position, but these improvements also resulted in larger open positions. During the Deferral Period, the open positions in July and August reached nearly 2,000 megawatts. This large open position continues to pose several risks to the

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[11] How Blackouts During Heat Waves Amplify Mortality and Morbidity Risk at 8250. Brian Stone Jr. et al. Environmental Science & Technology 2023 57 (22), 8245-8255, available at https://pubs.acs.org/doi/10.1021/acs.est.2c09588?ref=pdf

Companies. The most significant risk is the risk that supplies in the market may be constrained at the same time that the utilities need additional supply to meet their needs. A second risk is that the transactions that utilities use to meet their needs may not be backed by physical assets. This could result in circumstances where the counterparty is unable to procure physical power in real time to meet the obligations of their contract to the Companies. Both of these risks have been highlighted in previous summers with high power prices in conjunction with supply curtailments throughout the region.

15. Q. WHAT WAS THE RFP SCHEDULE TO PROCURE PHYSICAL POWER FOR THE DEFERRAL PERIOD?

A. Consistent with prior years, the Company used a competitive RFP process to procure physical power for delivery during the Deferral Period. Copies of the RFPs issued for physical power are provided as **Exhibit Atkins-Direct-8**. Procurements were made on the same day of bid submission deadlines. The bid submission deadlines were:

1) October 13, 2021, for a portion of the summer 2023 requirement;
2) January 26, 2022, for a portion of the summer 2023 requirement;
3) November 3, 2022, for a portion of the summer 2023 requirement;
4) February 9, 2023, for a portion of the summer 2023 requirement; and
5) April 13, 2023, for a portion of the summer 2023 requirement.

16. Q. WHAT CRITERIA WERE USED TO EVALUATE RFP BIDS FOR PHYSICAL POWER SUPPLY?

A. The criteria used to evaluate the bids included cost, deliverability, reliability, creditworthiness of prospective suppliers, payment terms, legal and contractual issues, and any other terms and conditions applicable to the prospective purchase. Upon receipt of the bids, the team reviewed the bids and resolved any legal or contractual issues. Resource Optimization then analyzed the bids according to cost, and deliverability, and made contract execution recommendations to the team. Once an agreement was reached in accordance with the Company's policies and procedures, the appropriate execution authority within Resource Optimization executed the transactions.

17. Q. PLEASE DESCRIBE THE RESULTS OF THE RFP PROCESS FOR THE POWER PROCURED FOR THE DEFERRAL PERIOD.

A. Sierra was successful with the RFPs in obtaining physical power for the Deferral Period. An adequate number of counterparties participated with competitive pricing. The open position could not be entirely filled with non-CAISO sourced supply however, as a result of limited market availability of such supply.

18. Q. WERE CAISO RULES A CONCERN DURING THE DEFERRAL PERIOD?

A. Yes. Market concerns continued to be compounded by the CAISO change in day-ahead export priorities implemented in the summer of 2021, its ongoing Wheel Through Initiative, and the 2023 change to e-tag rules that introduced a new firm provisional energy priority starting in July of 2023. The 2021 change to export priorities has allowed CAISO to adjust day-ahead export schedules to zero with potentially less than an hour's notice on whether the energy will flow. This has resulted in uncertainty on the delivery status for energy sourced out of the CAISO on high load days. Day ahead export awards can be adjusted to zero as a part of the residual unit commitment process with no certainty on resupply until approximately 55 minutes before the start of the flow hour. This can lead to challenges in resource adequacy planning on an hour-to-hour basis. Following up on this change were new rules for tagging exports from the CAISO that were implemented on July 1, 2023, as a part of the EIM Resource Sufficiency Evaluation Enhancement Phase 2 Initiative. The rule change requires low-priority exports to be tagged as firm provisional energy in contrast to the historical practice of tagging the energy as standard firm energy. While firm provisional energy does technically meet the qualifications of the Western Systems Power Pool Schedule C (firm) energy, significant curtailments to CAISO exports have already occurred in the short time since the rule changes were implemented. These rules highlight the uncertainty and risk associated with purchasing CAISO sourced supply that is not backed by an asset and ultimately deemed as low priority. In addition, since April 2021 when the CAISO filed revisions to its tariff at the Federal Energy Regulatory Commission to modify the load, export, and wheeling priorities, there has been a lack of clarity on available transmission capacity through California and the true firmness of using such transmission. This has added additional uncertainty to any firm energy purchases sourced from the Pacific Northwest and flowing through California to a Desert Southwest sink.

19. Q. DID SIERRA IDENTIFY A NEED TO PROCURE NON-CAISO SOURCED ENERGY?

A. Yes. As discussed in the previous question, changes to CAISO market rules have added uncertainty to the firmness of energy sourced from the CAISO. Prior to 2020, counterparties had historically been able to count on purchases from CAISO being firm in nature, despite not being backed by any sort of identified physical asset. However, with the recent rule changes, and the heightened resource adequacy issues within California, these purchases being exported out of the CAISO cannot, and should not be counted on for the most critical summer days and hours. In talking with neighboring utilities, it is common practice to ensure any market purchases made for reliability purposes are backed by an asset or a firm system other than CAISO.

20. Q. DID SIERRA SUPPLEMENT ITS RFP ACTIVITIES WITH DIRECT NEGOTIATIONS WITH COUNTERPARTIES FOR CUSTOMIZED PRODUCTS TO CLOSE THE OPEN POSITION?

A. Yes, to close the approved open position with non-CAISO sourced energy and shaped products, additional transactions were analyzed and executed outside of the RFP process. These additional transactions included:

1) Agreements with Nevada Cogeneration Associates ("NCA") #1 and #2
2) Agreement with Saguaro Generating Facility
3) Bilateral transactions with counterparties for non-CAISO supply
4) The Companies also bid into a reverse RFP issued by PowerEx in 2021 for summer supply in 2023 sourced off the British Columbia Hydro System

21. Q. WERE THERE OTHER AGREEMENTS IN PLACE OUTSIDE THE STANDARD SHORT TERM PURCHASE POWER ACTIVITIES?

A. Yes. An agreement remained in place with Tonopah Solar Energy, LLC, for the output of the Crescent Dunes Solar and Molten Salt Storage facility. This agreement was in place for the entirety of the Deferral Period with a tiered rate structure based on season and hour. This is an in-state renewable facility that was willing to take an under-market price in order to prove out its technology in hopes for a longer term PPA.

22. Q. WAS IT REASONABLE FOR THE COMPANIES TO NEGOTIATE DIRECTLY WITH COUNTERPARTIES OUTSIDE OF THE RFP PROCESS IN ORDER TO CLOSE THEIR OPEN POSITION?

A. Yes. Saguaro, NCA #1, and NCA #2 are all in-state generators that have been reliable producers under previous PPAs with the Companies and were priced competitively. Several other counterparties approached the Companies with non-CAISO supply that was only available outside of the normal RFP cadence and the prices were competitive with previous RFP results and prevailing market conditions.

23. Q. WAS IT REASONABLE FOR THE COMPANIES TO PARTICPATE IN THE POWEREX REVERSE RFP IN 2021 TO PROCURE SUPPLY FOR THE 2023 DEFERRAL PERIOD?

A. Yes. The Companies participated in the reverse RFP in 2021 and procured supply for multiple summers which was a reasonable and prudent decision. PowerEx is known to hold long-term transmission positions throughout the western United States, which allows it to schedule energy on a variety of paths and gives it the ability to resupply supply if emergencies arise. In addition, PowerEx provides access to hydroelectric resources during peak periods in Nevada. PowerEx has been one of the Companies' more reliable suppliers. Analysis was performed using available information to identify the prevailing market conditions at the time of the RFP and the approximate market value of non-CAISO supply. As previously discussed in deferred filings, a meeting was held with the Commission's Regulatory Operations Staff ("Staff") on November 19, 2021, to review the RFP, and Staff was in consensus the prudent action was to pursue the maximum amount of available energy for up to a three-year term. This information was also presented to the Risk

Committee who agreed the bids were prudent and the energy supply was highly reliable.

24. Q. DID ANY CONTRACTUAL ISSUES ARISE WITH TRANSACTIONS EXECUTED TO CLOSE THE OPEN CAPACITY POSITION?

A. Yes. NCA #1 made the decision to shut down during the month of January 2023. This decision was made at the sole discretion of NCA #1 and was not related to operational issues. Representatives from NCA #1 noted they made the decision based on economics due to the increase in natural gas prices during the December 2022 and January 2023 timeframe. The Company determined NCA #1 was in breach of contract and ultimately pursued liquidated damages. Resource Optimization performed a review of market prices compared to the contract cost for NCA #1 and ultimately reached a settlement agreement with NCA #1 to be reimbursed for the cost of replacement energy in the amount of $1,491,959.

25. Q. DID THE COMPANIES IDENTIFY A NEED TO BUY PRODUCTS WITH DIFFERENT HOURLY SHAPES?

A. Yes. The Companies continuously analyze system and load conditions that may result in different shaped products being procured. The Companies procured a mix of standard on-peak, super-peak, as well as custom non-standard products in order to match their needs and operational requirements. Staggering the products over different time frames allowed the Companies to better manage system reliability constraints such as hourly ramping limitations or potential oversupply conditions during morning hours.

26. Q. DID THE COMPANIES EXPERIENCE CURTAILMENTS BY SUPPLIERS OF FIRM ENERGY DURING THE SUMMER OF 2023?

A. Yes. The most significant curtailment event occurred on the evening of July 25, 2023. The Companies experienced curtailments to their CAISO sourced supply of nearly 750 megawatts over the critical evening peak period. This was despite the CAISO only being in an EEA Watch situation and loads in California reaching only approximately 43,000 megawatts. Because the CAISO has the ability to curtail low priority exports, it continues to highlight the need for the Companies to continue to pursue asset backed transactions that reduce the risk of curtailment from the CAISO. In follow up discussions with CAISO leadership, it was made clear that exports from California can no longer be supported on a consistent basis going forward.

27. Q. DID THE COMPANIES UTILIZE THE SPOT MARKET TO BALANCE LOADS AND RESOURCES AND MINIMIZE COSTS FOR CUSTOMERS THROUGHOUT THE DEFERRAL PERIOD?

A. Yes. The Companies engaged in short term transactions both on an hourly and day-ahead basis. These transactions are done to both optimize the Companies' generation portfolio and also to ensure the Companies can meet load and reliability requirements. The Companies continuously evaluate system and market conditions, and utilize a short-term optimization model to determine the least cost system plan and whether spot market transactions are prudent.

28. Q. PLEASE IDENTIFY ALL POWER TRANSACTIONS RELEVANT TO THE DEFERRAL PERIOD

A. **Exhibit Atkins-Direct-5** lists the power purchase transactions that were entered into either immediately before or during the Deferral Period and that also flowed during the Deferral Period. These transactions were entered into by the Company during the laddering power procurement process, as well as the current and subsequent, or "prompt" month.

29. Q. DID THE COMPANY PROCURE PHYSICAL POWER IN COMPLIANCE WITH ITS ESP AND ESP UPDATES?

A. Yes. The Commission-approved ESP, ESP updates and supplemental and additional ESP updates that govern the Company's activities called for a laddering approach to forward purchases of physical power and/or capacity to manage the open capacity position for four seasons ahead. The Company procured adequate physical power to meet its load obligations in compliance with the applicable ESP, ESP updates and supplemental and additional ESP updates. The prudence behind the purchases and strategy is further discussed in the prepared direct testimony of Eugene T. Meehan from National Economic Research Associates ("NERA").

30. Q. PLEASE SUMMARIZE YOUR TESTIMONY REGARDING THE COMPANY'S PHYSICAL POWER PROCUREMENT FOR THE DEFERRAL PERIOD.

A. Sierra procured physical power for the Deferral Period in accordance with corporate policies and procedures, the Commission-approved ESP, ESP updates, and supplemental and additional ESP updates. The physical power supply procured for the Deferral Period was obtained through competitive processes and at prices and terms that were consistent with prevailing market conditions. In summary, the recorded costs associated with the procurement of physical power supply for the Deferral Period were reasonable.

31. Q. WHAT WERE THE GAS MARKET CONDITIONS IN THE WESTERN UNITED STATES DURING THE DEFERRAL PERIOD?

A. A number of factors impacted natural gas markets and led to a rise in prices and volatility early in the deferral period. The conflict between Russia and Ukraine throughout 2022 was a major driver that led to supply disruptions for many European countries. This led to increased European demand for liquified natural gas ("LNG") and European demand for LNG directly competes with domestic demand. Elevated European prices incentivized additional North American LNG exports. With this dynamic as a backdrop, a number of additional events occurring simultaneously in the west added additional pressure and contributed to record prices in December 2022 as natural gas spot prices exceeded $50.00/MMBtu. In January of 2023, the U.S. Energy Information Administration ("EIA") published a report that concluded the pricing event was the result of a number of key factors.[12] More specifically, below-normal temperatures on a regional level, lower natural gas imports from Canada, elevated natural gas consumption, pipeline constraints (i.e. maintenance in west Texas), and low natural gas storage levels in the Pacific region all contributed to the western pricing event. This event, while beginning in December 2022, had major impacts on prices in January 2023. Western prices started to soften in mid-January of 2023 and remained below the previous year for the balance of 2023. Increased natural gas production and mild weather throughout most of 2023 contributed to above-average natural gas levels in U.S. storage. As reported by the EIA, "relatively mild temperatures, record production, and higher-than-average inventories reduced natural gas prices."[13]

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[12] *Daily natural gas spot prices in western United States exceed $50.00/MMBtu in December*, U.S. EIA (Jan. 24, 2023), https://www.eia.gov/todayinenergy/detail.php?id=55279

[13] *Natural gas prices fall in first of 2023 amid record production and mild temperatures*, U.S. EIA (July 24, 2023), https://www.eia.gov/todayinenergy/detail.php?id=57200

32. Q. DID THE DECEMBER 2022 PRICING EVENT IMPACT THE DEFERRAL PERIOD?

A. Yes. The December pricing event was significant as it impacted the settlement prices for baseload gas in January of 2023. Consistent with the Company's four-season laddering strategy, the majority of natural gas procured for January 2023 was originated over the course of four RFPs, well in advance of the operating month, at indexed prices. The indexed prices settled against trading activity that took place during the final days of December 2022, for January 2023 delivery. Effectively, there was a lag in which the Company experienced the December 2022 price excursion. As discussed further in the testimony of Kurt G. Strunk from NERA, the Company's approved procurement strategy depends on market-based purchases of natural gas which naturally leads to higher costs when market prices are high. While the Company experienced these higher market costs in January 2023, it was also able to benefit from lower market prices for natural gas for most of the remainder of the Deferral Period.

33. Q. WHAT WAS THE RFP SCHEDULE TO PROCURE PHYSICAL GAS FOR THE DEFERRAL PERIOD?

A. Consistent with prior years, the Company used a competitive RFP process to procure physical gas for delivery during the Deferral Period. Copies of the RFPs issued for physical gas are provided as **Exhibit Atkins-Direct-6**. Procurements were made within a few weeks of bid submission deadlines. The bid submission deadlines were:

1) March 1, 2021, for a portion of the requirement for 2023;
2) August 31, 2021, for a portion of the requirement for 2023;
3) March 9, 2002, for a portion of the requirement for 2023;

4) September 7, 2022, for a portion of the requirement for 2023;

5) March 2, 2023, for a portion of the requirement for 2023; and

6) September 13, 2023, for a portion of the requirement for 2023.

34. Q. PLEASE DESCRIBE THE STEPS LEADING UP TO THE ISSUANCE OF EACH PHYSICAL GAS RFP.

A. Before issuing an RFP, a principles and strategy document is prepared to memorialize, without limitation: the approved procurement targets; basin distribution of procurements and representation of constraints; gas transport losses and adders; the verification of appropriate documentation or other requisite agreements per counterparty; credit constraints per counterparty; legal or regulatory issues; the valuation approach (i.e., inclusion of responsive bids or exclusion of non-responsive bids); and the risk management of modeling errors. The principles and strategy document is reviewed by several groups or departments (i.e., Contracts, Credit, Legal, Risk Control, Resource Planning and Analysis, and Resource Optimization) both prior to issuing the RFP and upon the preparation of transaction plans. This represents an auditable determination of the nature, source, quality, and timing of the information or analysis informing decisions on prudent procurement.

35. Q. WHAT CRITERIA WERE USED TO EVALUATE BIDS FOR PHYSICAL GAS SUPPLY?

A. The criteria used to evaluate the bids included cost, reliability, creditworthiness of prospective suppliers, payment terms, legal and contractual issues, and any other terms and conditions applicable to the prospective purchase. Consistent with previous years, the Company relied upon a spreadsheet model designed to select the most economic bids subject to constraints such as limits on transport capacity.

Upon receipt of the bids, the Resource Optimization and Resource Planning teams reviewed the bids and resolved any legal or contractual issues. The teams utilized the spreadsheet model and analyzed the bids according to cost, adequacy and reliability, and made contract execution recommendations to the team. Once an agreement was reached in accordance with Sierra's policies and procedures, the appropriate execution authority within Resource Optimization executed the transactions.

36. Q. PLEASE DESCRIBE THE RESULTS OF THE RFP PROCESS FOR THE GAS PROCURED FOR THE DEFERRAL PERIOD.

A. Sierra was successful with the RFPs in obtaining physical gas for the Deferral Period, with adequate supplies and transportation, multiple counterparties participating, and competitive pricing. Copies of the RFPs issued for physical gas are provided as **Exhibit Atkins-Direct-6**. Gas transactional data is provided as **Exhibit Atkins-Direct-7.** Transactions have been reviewed by Mr. Strunk from NERA who discusses the prudency in his direct testimony.

37. Q. THE COMPANY PROCURES PHYSICAL GAS AT INDEXED PRICES SUBJECT TO A CAP ON THE PREMIUM. THE CAP CAN BE EXCEEDED UNDER CERTAIN CIRCUMSTANCES. DID SUCH A SITUATION ARISE IN 2023?

A. Yes, Resource Optimization sought Risk Committee approval on February 15, 2023, and August 16, 2023, to transact at the lowest estimated total cost. The transaction authority provided by the relevant body was applied to executions for delivered gas where premiums exceeded the cap for all conforming bids and were the least cost supply alternative. Consistent with the Commission approval in Docket No. 17-09001, no notification was required in 2023 for transactions above the cap as those transactions were the least cost supply alternative. The market dynamics surrounding the higher premiums paid by the Company in 2023 is discussed further in the testimony of Mr. Strunk from NERA.

38. Q. DID THE COMPANY CONTINUOUSLY OPTIMIZE ITS PHYSICAL GAS PORTFOLIO DURING THE DEFERRAL PERIOD?

A. Yes. Adjustments to the portfolio were made through the short-term gas supply marketplace. On a monthly basis, procurements were compared to the appropriate target volumes, and gas supplies were adjusted as needed. This provides an additional risk management tool complementing the continuous adjustment of the portfolio to reflect changes in load, system reliability, or market conditions; and the layering in of purchases or sales over time, beginning a year or more prior to the delivery period and continuing until the day of delivery. These adjustments, which may be a purchase or a sale, were made during or before the Gas Industry "Bid Week" when month-ahead physical gas transactions take place. Transactions executed during Bid Week are either executed on the Intercontinental Exchange ("ICE") or negotiated through bilateral agreements with credit-approved counterparties. On a daily basis, adjustments were made, depending on holiday and weekend schedules, between 24 and 120 hours in advance of physical delivery. The real-time generation trading desk communicates with gas trading at least twice daily to adjust incoming gas supply volumes as required. All gas supply transactions involve market surveys of available and responsive counterparties and a review of ICE prior to actual transactions.

39. Q. PLEASE IDENTIFY ALL PHYSICAL GAS TRANSACTIONS RELEVANT TO THE DEFERRAL PERIOD.

A. **Exhibit Atkins-Direct-7** summarizes Sierra's purchases of physical gas transactions for the Deferral Period. These transactions were entered into by the Company during the laddering gas procurement process, as well as the current and subsequent, or "prompt" month.

40. Q. DID THE COMPANY PROCURE PHYSICAL GAS IN COMPLIANCE WITH ITS ESP AND ESP UPDATES?

A. Yes. The Commission-approved ESP, ESP updates and supplemental and additional ESP updates that govern the Company's activities called for a laddering approach to forward purchases of physical gas at indexed prices for four seasons ahead. The Company procured adequate physical gas to meet its load obligations in compliance with the applicable ESP, ESP updates and supplemental and additional ESP updates.

41. Q. DID THE COMPANY CONDUCT INFORMATIONAL WORKSHOPS DURING 2023 WITH STAFF AND BUREAU OF CONSUMER PROTECTION ("BCP")?

A. Yes. Two workshops were held in 2023 on June 29, 2023, and October 4, 2023. Copies of presentations and the attendance lists from those workshops are provided in Technical Appendix 1. Pursuant to Docket No. 19-08034, the Company provided information related to gas market fundamentals to Staff and BCP in lieu of holding workshops in the remaining quarters of 2023.

42. Q. DID THE COMPANY PROCURE ANY GAS HEDGES OR PAY ANY SETTLEMENT FEES IN 2023?

A. No.

43. Q. DID SIERRA UNDERTAKE OTHER TRANSACTIONS THAT REDUCED THE OVERALL COST OF PROVIDING SERVICE TO ITS CUSTOMERS?

A. Yes. The Company issued an RFP for an Asset Management Agreement ("AMA") involving its natural gas storage capacity at the Jackson Prairie Storage Facility and gas transportation assets in and around the Jackson Prairie Storage Facility for the periods of November 1, 2022, through October 31, 2023, and November 1, 2023, through October 31, 2024. An AMA is a pre-arranged release of gas transportation or storage capacity to an asset manager in exchange for an agreed-upon monetary return. It has conditions under which the asset owner, on any day during the released period, may call upon the asset manager to deliver up to 100 percent of the released daily capacity.

44. Q. WHAT IS THE RATIONALE FOR THE AMA?

A. The Company needs storage capacity for peak demand. The asset manager captures the value of this capacity when it is not used by the Company, and the Company continues to have usage rights to serve native load when and as needed. The arrangement allows the Company to retain usage rights when and if needed, but at a lower overall cost because the asset manager pays the Company for its usage of the asset during the times the Company does not need it.

45. Q. WHAT ARE THE REGULATORY FOUNDATIONS OF THE AMA?

A. Issued by Federal Energy Regulatory Commission ("FERC") on June 19, 2008, and made effective on July 30, 2008, FERC Order No. 712 approved changes to transportation and storage release regulations to allow the use of AMAs. FERC recognized the benefits of allowing transportation and storage holders to outsource capacity using AMAs, which achieves more efficient capacity utilization of interstate pipelines and gas storage, provides additional value to asset owners, and lower costs for customers. AMA utilization is on interstate pipelines which are regulated by FERC.

46. Q. WHAT WAS THE COMPANY'S PROCESS FOR THE AMA RFP?

A. The RFPs were issued to approximately 50 bidders. There was adequate participation with multiple bids received. An internal team reviewed the bids and a counterparty was selected. Both the bid amount and counterparty viability were considered in the selection process. The AMA was executed for a monetary return to the Company's customers of $2.7 million for the November 1, 2022, to October 31, 2023, release term, and $4.5 million for the November 1, 2023, to October 31, 2024, release term. Resource Optimization performs continuous monitoring of the AMA's value.

47. Q. PLEASE SUMMARIZE YOUR TESTIMONY REGARDING THE COMPANY'S PHYSICAL GAS PROCUREMENT FOR THE DEFERRAL PERIOD.

A. Sierra procured physical gas for the Deferral Period in accordance with corporate policies and procedures, the Commission-approved ESP, ESP updates, and supplemental and additional ESP updates. The physical gas supply procured for the Deferral Period was obtained through competitive processes and at prices and terms that were consistent with prevailing market conditions. In summary, the recorded costs associated with the procurement of physical gas supply for the Deferral Period were reasonable.

48. Q. DID SIERRA ACQUIRE COAL DURING THE DEFERRAL PERIOD?

A. Yes. In addition to the need to run the North Valmy Station for summer reliability, voltage requirements in the Sierra service territory required at least one Valmy unit to be online at all times for the entirety of the year. For 2023 deliveries, Sierra solicited supply proposals from qualified coal suppliers through the RFP process and through bilateral negotiations and transacted for coal from the coal producing regions of central Utah, western Colorado, Montana, and southern Wyoming.

49. Q. WHAT WERE THE COAL MARKET CONDITIONS IN THE WESTERN UNITED STATES DURING THE DEFERRAL PERIOD?

A. A number of factors continued to impact coal markets and led to elevated prices. A main driver was a continued increase in coal demand internationally that led to an increase in coal exports which impacted prices domestically. The quality specifications (specifically mercury and sulfur levels) remained poor compared to previous years, which put a further squeeze on supply. Additionally, railroads continued to struggle to deliver coal on schedule and still have not returned to pre-COVID delivery time frames. Finally, significant issues at mines in the West also contributed to supply disruptions. For example, the Lila Canyon mine in Utah was permanently shut down after ongoing issues following a significant fire. The Skyline mine in Utah experienced flooding issues that resulted in wet and unusable coal. The West Elk coal mine in Colorado sent force majeure letters to its customers due to unexpected geological issues which impacted their ability to produce coal. All of these factors led to challenging market conditions that impacted many coal burning facilities in the West.

50. Q. PLEASE DESCRIBE SIERRA'S EVALUATION OF THE COAL SUPPLY PROPOSALS RECEIVED.

A. Sierra's evaluation of proposals received included the price delivered to North Valmy Station in dollars per MMBtu, coal quality, and reliability of supply. Coal quality parameters of the candidate source mines were screened and reviewed with the North Valmy Station technical staff, with the objective of providing coal supplies that enabled efficient operations of the coal-fired units while meeting all environmental regulations.

51. Q. PLEASE DESCRIBE THE COAL SUPPLY CONTRACTS SIERRA ENTERED INTO DURING THE DEFERRAL PERIOD.

A. During 2023, Sierra purchased coal supplies conforming to North Valmy Station Unit 1 and Unit 2 requirements. A total of approximately 600,000 tons was delivered during the deferral period. Coal supply contracts were entered into with: Arch Coal Sales Company for approximately 178,000 tons from its West Elk Mine in western Colorado, Black Butte Coal Company for approximately 12,000 tons from its Black Butte Mine in southern Wyoming, Peabody Coal Sales for approximately 59,000 tons from its 20 Mile Mine in western Colorado, PGC LLC for approximately 220,000 tons from the Spring Creek Mine in southern Montana, and Kemmerer Operations LLC for approximately 138,000 tons from its Kemmerer Mine in southern Wyoming.

52. Q. PLEASE SUMMARIZE YOUR TESTIMONY REGARDING THE COMPANY'S COAL PROCUREMENT FOR THE DEFERRAL PERIOD.

A. Sierra procured coal for the Deferral Period in accordance with corporate policies and procedures, the Commission-approved ESP, ESP updates, and supplemental and additional ESP updates. Each of the coal transactions reflected prevailing market conditions for suitable quality coal for North Valmy Unit 1 and Unit 2. In summary, the recorded costs associated with the procurement of coal for the Deferral Period were reasonable.

53. Q. **IS THE COMPANY REQUESTING CONFIDENTIAL TREATMENT OF CERTAIN INFORMATION INTENDED TO GUIDE THE PURCHASE AND SALE OF ENERGY PRODUCTS?**

A. Yes. Confidential information has been redacted from Technical Appendix 1.

54. Q. **PLEASE DESCRIBE THE CONFIDENTIAL MATERIAL.**

A. The redacted material includes fuel forecast and pricing information. This material is commercially sensitive and/or discloses the Company's views and expectations of its costs and capabilities to serve both existing and potential forward sales.

55. Q. **FOR HOW LONG DOES SIERRA REQUEST CONFIDENTIAL TREATMENT?**

A. The requested period for confidential treatment is for no less than five years.

56. Q. **WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF STAFF OR BCP TO PARTICIPATE IN THIS DOCKET?**

A. No, in accordance with the accepted practice in Commission proceedings, the confidential material will be provided to Staff and the BCP under standardized protective agreements with them.

57. Q. **IN CONCLUSION, WERE THE TOTAL COSTS INCLUDED IN THE DEAA BALANCES REASONABLY INCURRED?**

A. Yes. Transactions complied with the governing Commission-approved ESP or ESP updates, and liquidity and price discovery were adequate. The Company appropriately and efficiently used available resources to provide electric services to customers at reasonable costs. In summary, all of the purchase and sale transactions included in the deferred energy balances at issue in this case were executed in a manner that is consistent with reasonable strategies previously approved by the Commission and with appropriate procedures governed by the Company's risk management and control policies. The prices of products purchased and sold were consistent with prevailing market conditions at the time of execution.

During the Deferral Period, and discussed thoroughly by Company witnesses, the Company: (a) dispatched its generating units in an efficient and appropriate manner in light of the prevailing conditions; (b) procured fuel in a prudent manner; (c) optimized its fuel resources in an appropriate manner to capture value for the benefit of its customers by offsetting fuel and purchased power costs; and (d) optimized its gas transportation capacity to capture value for the benefit of its customers by offsetting fuel and purchased power costs.

58. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does.