BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

In the Matter of the Application by Nevada Power Company d/b/a NV Energy, filed pursuant to NRS 704.110(3) and NRS 704.110(4), addressing its annual revenue requirement for general rates charged to all classes of electric customers.	**Docket No. 25-02___**

NEVADA POWER COMPANY D/B/A NV ENERGY

VOLUME 9 OF 19

TESTIMONY

Recorded Test Year ended September 30, 2024
Certification Period ending February 28, 2025
Expected Change in Circumstance Period ending September 12, 2025

CHRISTOPHER BELCHER

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 25-02___
2025 General Rate Case

Prepared Direct Testimony of

Christopher Belcher

Revenue Requirement

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

A. My name is Christopher Belcher. My current position is Integrated Energy Services ("IES") Policy and Compliance Manager for Nevada Power d/b/a NV Energy ("Nevada Power" or the "Company") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra," and together with Nevada Power, the "Companies"). My business address is 6226 West Sahara Avenue, Las Vegas, Nevada 89146. I am filing testimony on behalf of Nevada Power.

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

A. The details of my background and experience are provided in **Exhibit Belcher-Direct-1.**

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS THE IES POLICY AND COMPLIANCE MANAGER.

A. As the IES Policy and Compliance Manager, my responsibilities include managing the technical inputs to the Companies' Demand Side Management ("DSM"), energy efficiency and conservation ("EE&C"), and Renewable Energy programs,

Nevada Power Company
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as well as the transportation electrification plans. I also manage the required compliance items for the DSM, EE&C, Clean Energy plans ("CE"), as well as the Public Utilities Commission of Nevada ("Commission") directives resulting from these filings or any of the Companies' filings that require DSM, EE&C, and/or CE contributions.

4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes, I have previously submitted testimony before the Commission in several proceedings, including most recently Docket Nos. 23-02001 (the Companies' CE), 23-06007 (Nevada Power's General Rate Case ("GRC")), 23-06044 (DSM Update), 24-02026 (Sierra's GRC), and 24-05041 (2024 Joint Integrated Resource Plan).

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

A. In Section I of my testimony, I update the Commission on the current balance of Rule No. 15 tariff interconnection application fees that were collected from customers who applied to interconnect their personal generators, with capacity less than or equal 1 megawatt ("MW"), to the Company's grid. This application fee in the amount of $119 was approved by the Commission in Nevada Power's 2023 GRC.[1]

[1] Docket No. 23-06007, January 16, 2024, Tariff Approved by the Commission, Tariff No. 1-B, 5th Revised PUCN Sheet No. 93I, Rule No. 15, Generating Facility Interconnections (p. 96 of the PDF submission).

In Section II of my testimony, I explain the refund process for net metering customers that applied for net metering from 2021 through 2023. These applicants were eligible for a partial refund for the application cost.

In Section III of my testimony, I propose adjusting the amount of the Company's Rule 15 application fee for qualified net metering applicants whose generating facilities are less than or equal to 1 MW-AC. The data supporting the proposed changes to the application fee are based on the costs associated with processing the interconnection applications.

In Section IV of my testimony, I propose that relevant application process changes that were approved in the most recent Sierra GRC are extended and applied to Nevada Power's applicants.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibits:

Exhibit Belcher-Direct-1	Statement of Qualifications
Exhibit Belcher-Direct-2	Summary of Rule 15 Interconnection Application Processing Costs and Application Fees
Exhibit Belcher-Direct-3	External Contracting Costs and Allocations
Exhibit Belcher-Direct-4	Application Fees Calculations and Evaluations
Confidential Exhibit Belcher-Direct-5	List of Undeliverable Applicant Checks
Exhibit Belcher-Direct-6	Rule 15 Tariff Draft

7. Q. IS THE COMPANY REQUESTING CONFIDENTIAL TREATMENT OF CERTAIN INFORMATION CONTAINED IN EXHIBIT BELCHER-DIRECT-5?

A. Yes, confidential information has been redacted in **Confidential Exhibit Belcher-Direct-5**.

8. Q. PLEASE DESCRIBE THE CONFIDENTIAL MATERIAL.

A. **Confidential Exhibit Belcher-Direct-5** contains customer-specific information such as names, addresses, and refund check payments related to net metering application fees.

9. Q. FOR HOW LONG DOES THE COMPANY REQUEST CONFIDENTIAL TREATMENT?

A. The Company requests confidential treatment for no less than five years.

10. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF THE COMMISSION'S REGULATORY OPERATIONS STAFF ("STAFF") OR THE BUREAU OF CONSUMER PROTECTION ("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.

SECTION I. RULE NO. 15 TARIFF INTERCONNECTION APPLICATION FEE BALANCING ACCOUNT STATUS

11. Q. PLEASE DESCRIBE THE INTERCONNECTION APPLICATION FEE AS IT IS CURRENTLY DEFINED WITHIN THE COMPANY'S RULE NO. 15 TARIFF.

A. Qualified net metering applicants whose generating facilities are less than or equal to 1 MW-AC currently pay a fixed interconnection application fee of $119. Generation systems sized greater than 1 MW-AC are not eligible for net metering and follow a separate application and review process outlined in Rule No. 15. Those systems greater than 1 MW-AC pay an application fee equal to the actual costs of their unique application requirements and scope of work for review of that application.

12. Q. WHAT WAS THE AMOUNT REFLECTED IN THE COMPANY'S BALANCING ACCOUNT FOR RULE 15 INTERCONNECTION APPLICATION FEES AS OF SEPTEMBER 30, 2024?

A. The Company's balancing account shows an under-collection of $1.06 million for the period between January 1, 2024, through September 30, 2024, and $1.19 million for calendar year 2024. The Company projects a $1.69 million under-collection as of September 30, 2025, when the application fee is due to reset. Please reference **Exhibit Belcher-Direct-2** for a breakdown of the balancing account's monthly balance for calendar years 2021 through 2025 (projected).

13. Q. WHAT IS THE PROJECTED AMOUNT THAT WILL BE IN THE BALANCING ACCOUNT USED FOR RULE 15 INTERCONNECTION APPLICATION FEES AS OF FEBRUARY 28, 2025, THE END OF THE CERTIFICATION PERIOD?

A. The Company projects an under-collected balance of $1.20 million for the Certification Period ending on February 28, 2025. Please reference **Exhibit Belcher-Direct-2** for a breakdown of the balancing account's monthly projected balance. The balance is forecasted to increase because the current $119 application fee is not sufficient to cover both the under-collected balance and future projected costs.

14. Q. WHAT CAUSED THE UNDER-COLLECTION?

A. In 2023, the Company forecasted that application volumes would increase significantly during 2024. This forecast was based on the general increasing trend of actual application rates observed beginning in 2020. In anticipation of this increased volume, the Company increased its resources to ensure that all completed applications would be processed within 10 business days as required by NAC 704.8823(1). The increased resources included more external contractors and internal utility administration to review and approve net metering applications and provide level 1 and level 2 call center and email support services. The contract for the external contractor expired on December 31, 2023, and the Company was required to extend the contract for another year. The extended contract had updated increased pricing and plans to increase staffing levels to meet the Company's statutory and regulatory requirements. The costs to increase these resources were incurred in the beginning of 2024. The costs are reflected in **Exhibit Belcher-Direct-2.** The approved $119.00 application fee was insufficient to cover the costs of the increased resources procured to process the forecasted application volumes. This deficit accumulated during 2024 and resulted in an under-collected balance in the net metering application fees.

In addition, the Companies engaged a new contractor for application processing labor. The Companies transitioned to this new external contractor between August 2024 and December 2024. During this time, the new external contractor ramped up its operations and concurrently, the old external contractor ramped down its operations and began training the new external contractor, conducted quality assurance reviews of the new external contractor's work, and updated handbooks and other operational documentation. This gradual transition minimized interruptions to customer service levels and the Company's and contractors' abilities to meet the mandated application processing requirements. This concurrent work resulted in invoices submitted by both contractors during this transition period, which contributed to the balance of the costs charged to the balancing account. I provide more information below in Section III.

Internal Company labor also increased during 2024 as compared to 2023. The increased Company resources were involved in the planning, contract negotiations, training and onboarding, and management oversight related to the transition to the new contractor. Some tasks were also reassigned to internal Company resources where opportunities for improved customer service and cost savings were possible, including, for example, reassigning quality control and process management tasks to Company employees. While combined internal utility costs and external outside services costs were temporarily more expensive during 2024 due to the transition of contractors and reallocation of internal labor, the Company expects the changes made to result in future cost savings during 2025.

Application fee revenue also decreased from approximately $3 million in 2023 down to approximately $1.9 million in 2024. This is a result of fewer customers submitting applications for net metering system interconnection during 2024. The number of applications submitted and, therefore, the amount of fee revenue collected were steadily increasing between 2021 through 2023, which informed the Company's forecast in 2024. However, the decline of actual applications submitted in 2024 reversed this steadily increasing trend.

Overall, the under-collection can be summarized by the increased costs, transition between old and new contractors, and decreased fee revenue collected during 2024.

SECTION II. STATUS UPDATE ON THE REFUND PROCESS FOR NEVADA POWER NET METERING CUSTOMERS

15. Q. AS PROPOSED IN DOCKET NO. 20-06003 AND EXPLAINED IN YOUR TESTIMONY FROM DOCKET NO. 23-06007, DID THE COMPANY REFUND THE OVER-COLLECTED AMOUNT FROM THE NET METERING APPLICATION FEE BALANCING ACCOUNT?[2]

A. Yes. The Company issued refund checks or bill credits to all applicants who paid net metering application fees from January 1, 2021, through December 31, 2023.

16. Q. HOW DID THE COMPANY DETERMINE THE AMOUNT TO REFUND ON THE OVER-COLLECTED APPLICATION FEES?

A. In Docket No. 23-06007, the Commission accepted the Company's proposal to refund the over-collected application fees as recorded in the balancing account.[3] The refund was based on the account balance as of December 31, 2023, which was $2,148,901 as indicated in **Exhibit Belcher-Direct-2**. Ten percent of the balance

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[2] Docket No. 23-06007, Application Vol. 9 at 337, Prepared Direct Testimony of Christopher Belcher at 337, Q&A 14.
[3] *Id.* at 337, Q&A 14; Docket Nos. 23-06007 and 23-06008, February 16, 2024, Order at 4.

was set aside as a budget to pay for utility administrative costs incurred processing and issuing the refunds. This amount was set aside to keep the net metering refund administrative labor costs within the net metering balancing account, as opposed to paying the administrative labor costs through the Company's operation and maintenance budget. The remaining amount, less the 10 percent, was spread to all applicants who paid net metering application fees from January 1, 2021, through December 31, 2023. The Company determined the percentage share of the total fees collected that was contributed by each project application by following the calculations described in Q&A 15 of my direct testimony in Docket No. 23-06007.[4] That percentage was then multiplied by the amount over-collected to derive the refund each applicant received.

17. Q. HOW MUCH WAS REFUNDED TO QUALIFIED APPLICANTS?

A. Applicants that previously paid a $130 fee were refunded $32.75. Applicants that previously paid a $200 application fee were refunded $50.38. Applicants that previously paid a $500 application fee were refunded $125.95.

18. Q. WHEN DID THE COMPANY BEGIN THE REFUND PROCESS?

A. In my direct testimony from Docket No. 23-06007, I proposed to disburse the refunds during the first quarter of 2024.[5] However, this was the first occurrence for the Company issuing refunds for net metering application fees. Disbursement of these refunds was delayed because the financial and technical procedures to record and deliver the refunds did not previously exist for net metering applications. As a

[4] *Id.* at 337, Q&A 15.
[5] *Id.* at 338, Q&A 16.

result, the Company developed new procedures during the first quarter of 2024 and the Company began disbursing refunds in April 2024.

19. Q. HOW DID THE COMPANY DETERMINE WHICH PARTY RECEIVED THE APPLICATION FEE REFUND?

A. Project application forms that are submitted to the Company have a designated field to identify an "Applicant." The Applicant is the person or party who has access to the project application forms and is responsible for completing the forms, which includes the responsibilities of arranging for the payment of the application fee. While Nevada Power performed data cleanup to identify the Applicant recipient and the total amount to be issued as a refund, it was determined that there were two classifications of applicants: residential net metering applicants and solar and battery providers. Nevada Power communicated using the Applicant's email on file to announce that the project was entitled to a partial refund of the application fee.

The Applicant was responsible for identifying the appropriate refund recipient in instances where a party other than the identified Applicant paid the application fee. Any third-party financial arrangements between the Applicant and the original application fee payee, if they are different parties, are outside the purview of the Company.

20. Q. DID THE COMPANY ISSUE REFUNDS TO ALL APPLICANTS WHO QUALIFIED?

A. Yes, the Company issued refunds to all applicants who qualified. While the Company processed close to 52,000 refunds, some refunds were returned because they came back as undeliverable. For example, cases where a refund check could be undeliverable may include solar companies going out of business and homeowners who may have moved. **Confidential Exhibit Belcher-Direct-5** lists 56 individuals and legal entities with undeliverable applicant checks as of January 2025. The list contains the names, addresses, and refund amounts sent to all these applicants whose refund checks were returned or that were undeliverable due to not having an address.

21. Q. HOW DID NEVADA POWER FIRST BEGIN ISSUING REFUNDS TO RESIDENTIAL NET METERING APPLICANTS?

A. The Company originally prepared its refund processes to mail physical refund checks to the mailing address of the Applicant. To issue a physical refund check, the Company's accounts payable department must create a unique vendor profile for every individual or company entity receiving a refund. The vendor profile is assigned a unique identification within the accounts payable software so the transaction can be recorded in accordance with the Company's accounting policies.

22. Q. WHAT WAS THE COST OF PROCESSING AND MAILING A PHYSICAL REFUND CHECK?

A. The work that I describe above incurred internal utility administrative costs with overhead in addition to costs with check processing and postage. The cost of a refund check amounted to approximately $30 each. The magnitude of this check processing cost was sizeable compared to the actual refund dollar amounts. Continuing to process and mail physical refund checks also jeopardized the Company's ability to remain within the allocated administrative budget. Therefore, the Company adopted a more prudent and cost-effective approach to processing the remaining refunds.

23. Q. WHAT OTHER METHOD DID THE COMPANY DEPLOY TO DISBURSE REFUNDS TO APPLICANTS?

A. The Company explored the possibility of delivering the remaining refunds as bill credits applied to an Applicant's utility service account. Bill credits avoid both the laborious steps to create vendor profiles for applicants and the costs associated with printing and mailing a physical check. Therefore, the Company determined that issuing bill credits was a more cost-effective method to issue refunds to the remaining applicants.

24. Q. ARE BILL CREDITS AN EFFECTIVE SOLUTION FOR ALL APPLICANTS?

A. No, not for all, there are some limitations to the effectiveness of issuing bill credits for refunding net metering application fees. Those limitations include but are not limited to:

(1) bill credits can only be issued to applicants that are current active customers of the Company, which excludes any person or company who does business and is located in other states; (2) bill credits cannot be applied to former customers who have closed their Company accounts and moved away; (3) bill credits would not work if the applicant has gone out of business and owes outstanding debts to creditors; (4) bills credits cannot be applied to solar companies that applied on behalf of net metering customers; and (5) bill credits may not be the preferred refund method for net metering customers whose net metering systems may already be reducing their power bill.

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25. Q. HOW WERE THE REFUNDS ISSUED TO RECIPIENTS WHO WERE SOLAR AND BATTERY COMPANIES?

A. Many net metering applications are submitted by solar and battery companies on behalf of the host customer purchasing the system. The solar and battery companies often submit hundreds or thousands of net metering applications. Their business may also be located in another state, and they are not customers of the Company. Therefore, bill credits were not a viable solution for these solar and battery companies. The Company determined the most cost-effective method of refunding these companies was issuing a single physical check for the total refund amount for all the applications submitted. The Company reached out to these companies using the email on file to request the business's current mailing address and remittance address to issue a cumulative refund.

26. Q. WHAT STEPS DID THE COMPANY TAKE WHEN A REFUND CHECK WAS UNABLE TO BE ISSUED OR RETURNED AS UNDELIVERABLE?

A. First, the Company investigated the reasons that caused a refund check to be returned. So far, the Company has learned that checks may be returned or are otherwise unable to be issued because the Applicant has moved away and is no longer located at that address, the applicant has gone out of business and is not receiving mail at that address, or the applicant sought protection of a bankruptcy court. There may be other possible reasons yet to be encountered.

If the online search indicated that the applicant was out of business or going through bankruptcy, the applicant's name was referred to an internal department to further investigate and determine whether the Applicant had a Notice of Bankruptcy Case

Filing so that a check could be reissued to the appropriate party. The Notice of Bankruptcy Case Filing provided the name of the bankruptcy trustee and the Company was able to contact the trustee to verify who the appropriate recipient of the refund should be. Currently, the Company is in the process of reissuing checks to applicants that have filed bankruptcy, and checks will be reissued to the trustees.

For checks that remain undeliverable, please refer to **Confidential Exhibit Belcher-Direct-5** which provides the names, addresses, and individual amounts of all the applicants for whom checks were returned. The list includes the entities described above that are currently in bankruptcy proceedings

27. Q. WHAT IS YOUR PROPOSAL FOR FUNDS THAT REMAIN UNDELIVERABLE?

A. The Company proposes to use the funds that remain undeliverable to offset the amount of the under-collection as of September 30, 2025. Alternatively, in line with the process outlined in NRS 703.375, the Company can issue the aggregate amount of the unpaid refunds to the Commission. As indicated in NRS 703.375, any unclaimed money which remains in the custody of the Commission at the expiration of the prescribed two-year period would then escheat to the State.

28. Q. HOW MUCH OF THE BUDGET DID THE COMPANY EXPEND ON ADMINISTRATIVE COSTS FOR PROCESSING THE REFUNDS?

A. The Company spent $11,792 of the $214,890 that was set aside for refund processing and administrative costs.

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29. Q. WHAT WILL THE COMPANY DO WITH THE UNUSED PORTION OF THE ADMINISTRATIVE BUDGET?

A. Similar to the funds that remain undeliverable, Nevada Power proposes to use the $203,098 of unspent administrative budget to offset the amount of the under-collection.

SECTION III. RULE NO. 15 TARIFF INTERCONNECTION APPLICATION FEE PROPOSAL

30. Q. PLEASE DESCRIBE THE COSTS THAT THE COMPANY INCURS WHEN IT PROCESSES INTERCONNECTION APPLICATIONS.

A. The Company's incurred costs include external contracted labor to process the customers' applications, application workflow management software, online solar and energy storage cost estimation calculators, customer service, call center support, and technical advisory services support. The technical advisory services provide support for customers who request building energy modeling, bill impact analysis, technology evaluation, and guidance through the interconnection application process. The application workflow management software costs include a base software license plus a volumetric fee charged per application submitted for application data hosting costs. The software costs also include online cost estimation calculator tools that are hosted on the Companies' website. These calculator tools assist customers when exploring the costs of installing solar and energy storage. Internal utility administrative costs are also included for the Company to manage and oversee net metering application processes and external contractors. Please refer to **Exhibit Belcher-Direct-2** for a report on these costs during the Test and Certification periods, and **Exhibit Belcher-Direct-3** for cost estimates in future years based on contracted pricing.

31. Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE FEE FOR NET METERING SYSTEMS (CAPACITY LESS THAN OR EQUAL TO 1 MW)?

A. Yes. The Company proposes a new fixed fee of $189 per application. This proposed fee reflects the projected application processing costs and projected volume of submitted applications. **Exhibit Belcher-Direct-4**, page 2 of 5, provides a breakdown of the forecasted application volume and processing costs by category that were used to calculate the proposed application fee. Please refer to **Exhibit Belcher-Direct-6** for the proposed changes to the application fee table on PUCN Sheet No. 93I of the Rule No. 15 Tariff No. 1-B. The proposed $189 application fee is intended to cover the higher costs of maintaining the Rule No. 15 tariff's interconnection process. The intent of the balancing account is to match as closely as possible the interconnection processes' costs with an equal amount of fee collections to result in an ideal zero, or close to zero, balance.

As referenced above, the Company is also proposing to reduce the per application fee by applying the over-collection funds remaining from the 2021-2023 period, which consists of the remaining administrative budget and undeliverable amounts. The Company estimates the amount that will be available to offset costs at $501,388. As shown in **Exhibit Belcher-Direct-4**, page 3 of 5, applying these funds to offset costs for 2025-2028 reduces the application fee to $179.

32. Q. PLEASE DESCRIBE HOW THE PROPOSED NET METERING FEE WAS CALCULATED?

A. The proposed fee was calculated based on projected application processing costs divided by the forecasted number of applications submitted by customers during the period starting October 1, 2025, and ending September 30, 2028. The intent is for the total amount of application fees collected to offset total application processing costs and gradually eliminate the under-collected amount. Please reference **Exhibit Belcher-Direct-4**, page 2 of 5, for the detailed calculations that were filed in support of the proposed $189 fee.

33. Q. WHY IS THE COMPANY PROPOSING TO INCREASE THE APPLICATION FEE AMOUNT FROM THE CURRENT $119 TO THE PROPOSED $189, OR $179 WITH THE OFFSET?

A. The projected future costs from the fourth quarter of 2025 through 2028 are forecasted to be higher than the costs today generally due to the normal inflationary costs escalation. The Company is also proposing an increased fee due to the need to amortize the under-collected balance. The intent of the fee is to keep the accounting balance as close to zero as possible.

34. Q. WHAT STEPS IS THE COMPANY TAKING TO OPTIMIZE COSTS IN ORDER TO KEEP THEM AS LOW AS POSSIBLE?

A. The Company continues to explore any options to reduce costs where possible. The Company did not renew an extension for the contract with its prior net metering applications processing contractor, with the contract expiring on December 31, 2024. The Companies entered into a new contract with a new contractor that can perform the same required application review at lower cost. The term of this new contract began on January 1, 2025.

The Companies will also file applications no later than January 1, 2026, to update the Rule 15 interconnection tariffs in efforts to modernize the tariffs with the latest industry standards. The Company will host workshops throughout 2025 seeking

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reasonable recommendations from interested stakeholders for updating the tariff, which may be an opportunity to improve the net metering process efficiency and realize cost savings.

35. Q. WERE THERE ANY TEMPORARY COSTS ASSOCIATED WITH THE TRANSITION FROM THE OLD CONTRACTOR TO THE NEWLY PROCURED CONTRACTOR?

A. Yes, the old contractor and the new contractor were performing some concurrent work to transition the workload while maintaining continuity of processes to minimize impacts to net metering applicants. The work related to the transition of the contractors included, but was not limited to, updating the training and standard operating procedure documents, direct hands on training sessions conducted by the old contractor with the new contractor, quality control and assurance tests performed by the old contractor of the new contractor, configurations of the new contractor's business computer systems and ramp up of their internal processes, and any other work or tasks needed to seamlessly move all work to the new contractor. Due to this shared transition work, both contractors were temporarily billing the Company simultaneously for November and December 2024 as indicated in **Exhibit Belcher-Direct-2**.

36. Q. HAS THE COMPANY EVALUATED OTHER FEE AMOUNTS?

A. Yes, the Company modeled fee amounts of $119 and $184. The calculations involving the $119 fee are presented in **Exhibit Belcher-Direct-4**, page 4 of 5, and the calculations involving the fee amount of $184 are presented in **Exhibit Belcher-Direct-4**, page 5 of 5.

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The Company also derived the $158 fee amount as presented in **Exhibit Belcher-Direct-4**, page 1 of 5. The $158 amount represents an application fee sufficient to cover on-going processing costs for the 2025-2028 period without amortizing the under-collection amount.

37. Q. WHY DID THE COMPANY EVALUATE THE FEE AMOUNTS OF $119 AND $184?

A. The fee amount of $119 simulates a scenario where the Company keeps its currently approved fee and makes no changes. As shown in **Exhibit Belcher-Direct-4**, page 4 of 5, the $119 fee amount is insufficient and creates a $3.6 million deficit by the end of the third quarter 2028.

The fee amount that the Commission approved for Sierra in Docket No. 24-02026 was $184.[6] The Company evaluated the same amount to determine if it was also a reasonable fee for Nevada Power customers. As shown in **Exhibit Belcher-Direct-4**, page 5 of 5, the $184 fee amount comes close to balancing the Rule 15 application fee account but also results in a deficit.

Nevada Power does not recommend approving either the $119 or $184 application fee and provided these calculations for illustrative purposes only.

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[6] Docket No. 24-02026, November 12, 2024, Modified Final Order at 98, para. 302.

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SECTION IV. NET METERING PROCESS PROPOSALS

38. Q. PLEASE DESCRIBE THE COMMISSION'S DISCUSSIONS AND FINDINGS IN DOCKET NO. 24-02026 REQUIRING SIERRA TO STOP COLLECTING THE EXECUTED THIRD-PARTY SOLAR CONTRACT FROM APPLICANTS APPLYING FOR NET METERING INTERCONNECTIONS?

A. In the Modified Final Order, the Commission found that Sierra should not require the executed contract from the net metering installer be provided with the application for net metering interconnection.[7] The Commission stated that there is no statutory or regulatory basis to do so absent the previous program incentives.[8] However, Sierra is required to continue collecting these contracts for those systems where the property is rented to verify that the property owner is aware of and authorizes the proposed installation.[9]

39. Q. IS THE COMPANY CURRENTLY REQUIRING THAT NET METERING INTERCONNECTION APPLICANTS SUBMIT AN EXECUTED THIRD-PARTY SOLAR CONTRACT?

A. No, the Company determined that Nevada Power should stop collecting the third-party solar contracts from Nevada Power applicants to be consistent with the Commission's Order in Docket No. 24-02026 for Sierra. Nevada Power has stopped collecting these contracts, except for cases where a renter is applying for net metering system interconnection and requires property owner approval. This results in a uniformly maintained and administered application process for both companies.

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[7] *Id.* at 94, para. 287.
[8] *Id.*
[9] *Id.*

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40. Q. ARE THERE OTHER PROCESSES THAT THE COMPANY WILL MODIFY TO COINCIDE WITH SIERRA?

A. Yes. In Docket No. 24-02026, the Commission stated that, when customers or electrical contractors are non-responsive or fail to provide sufficient information to process the application after the second iterative review, Sierra should have the right to terminate the application.[10] Nevada Power proposes to implement the same application termination process to maintain an overall uniform administrative process between the Companies.

41. Q. WHEN WILL THE NEW PROCESS OF TERMINATING REPETITIVELY INCOMPLETE OR INCORRECT APPLICATIONS TAKE EFFECT?

A. As directed, this process will be explored with the involved parties through the Companies' upcoming Rule No. 15 tariff modification dockets.[11] The Companies have been ordered in the Companies' 2024 Joint Integrated Resource Plan to file a formal application to update Rule No. 15 on or before January 1, 2026.[12] This new process of terminating repetitively incorrect applications will not take effect until presumably in 2026 after the Commission's final order regarding the Rule No. 15 tariff modification dockets.

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

A. Yes.

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[10] *Id*. at 98, para. 303.
[11] *Id.* at 98, para. 304.
[12] Docket No. 24-05041, December 27, 2024, Order at 366, Directive para.16

EXHIBIT BELCHER-DIRECT-1

QUALIFICATIONS OF WITNESS

Christopher M. Belcher
Policy and Compliance Manager, Integrated Energy Services
NEVADA POWER COMPANY d/b/a NV Energy
SIERRA PACIFIC POWER COMPANY d/b/a NV Energy
6226 W Sahara Ave.
Las Vegas, NV 89146

EDUCATION AND QUALIFICATIONS

May 2024	M.S. in Electrical Engineering, Pennsylvania State University
Dec 2013	Graduate Certificate in Renewable Energy, University of Nevada, Reno
May 2013	Passed Nevada Professional Engineering exam
Jan 2011	Passed Nevada Fundamentals of Engineering exam
Dec 2011	B.S. in Electrical Engineering, University of Nevada, Las Vegas Minor Degree in Mathematics, University of Nevada, Las Vegas

PROFESSIONAL EXPERIENCE

May 2022 - Present	Policy and Compliance Manager, Integrated Energy Services - Drafts regulatory plans and reports for DSM, DRP, IRP, Clean Energy, Gas C&EE, and Transportation Electrification - Manages compliance items and Commission directives for the above areas - Assists with other regulatory filings relevant to the above areas
Oct 2021 – May 2022	Senior Engineer, Integrated Grid Planning, NV Energy - Calculating renewable energy distributed generation hosting capacity - Managing remote distribution line power sensor program - Technical support for Distributed Resources Plan
Feb 2019 – Oct 2021	Senior Engineer, Renewable Energy Programs, NV Energy - Submitted testimony and appeared before the Commission for Docket No. 21-05012 - Technical support for annual Distributed Resources Plan and Clean Energy program filings and data requests - Strong technical knowledge of renewables, energy storage, and EVs - Continued managing net metering application process

	- Strong knowledge of utility parallel interconnection tariffs
Jun 2013 – Feb 2019	Engineer II, Electric Metering Operations, NV Energy - Managed net metering application process - Cross-team collaboration to design software integrations between company systems - Technical support for Energy Storage utility metering in Docket Nos. 17-06014 and 17-06015 - Field inspections for metering installation and quality control - Troubleshooting net metering customer inquiries and meter complaints - Trained metering staff on renewable and energy storage technologies
Jan 2011 – Jun 2013	Engineer I, Demand Side Management, NV Energy - Forecasted demand reduction for company DR events - Tested and recommended emerging technologies for DSM programs - Measure and verified DMS program performance using industry standard statistical analyses - Technical support for DOE Grant to install energy storage batteries, DSM, and energy efficient construction - Scheduled and operated demand response events - Quality assurance testing of DSM program hardware and software - Field installation and inspections of DSM program technologies

EXHIBIT BELCHER-DIRECT-2

Nevada Power
Summary of Rule 15 Interconnection Application Processing Costs and Application Fees
Account 254192

	2021 Month:	1	2	3	4	5	6	7	8	9	10	11	12	2021 Total
Outside Services Costs	Customer Call and Email Support	10,340.00	10,341.00	21,031.40	2,524.60	11,180.40	13,552.00	24,384.00	16,016.50	16,270.60	16,516.50	16,940.00	15,186.00	174,283.00
	Software	21,831.52	21,831.52	21,831.52	21,831.52	21,831.52	21,831.52	163,945.50	30,500.50	30,500.50	30,500.50	30,500.50	30,500.50	447,437.12
	Application Processing and Labor	61,223.85	63,334.33	56,111.00	61,842.85	56,441.90	64,211.94	58,901.85	61,022.53	58,875.84	61,729.81	61,775.84	61,441.65	726,913.39
	Monthly Total Outside Services >	**93,395.37**	**95,506.85**	**98,973.92**	**86,198.97**	**89,453.82**	**99,595.46**	**247,231.35**	**107,539.53**	**105,646.94**	**108,746.81**	**109,216.34**	**107,128.15**	**1,348,633.51**
Utility Costs	Internal Labor/Overhead	2,189.49	2,271.52	2,738.18	1,975.84	1,921.04	1,709.41	2,134.68	3,879.04	2,697.28	1,668.10	1,619.08	1,525.77	26,329.43
	Expense Report	4.46	4.91	5.42	5.96	6.26	6.26	10.47	10.68	10.68	10.90	10.90	10.57	97.47
	Monthly Total Utility Admin >	**2,193.95**	**2,276.43**	**2,743.60**	**1,981.80**	**1,927.30**	**1,715.67**	**2,145.15**	**3,889.72**	**2,707.96**	**1,679.00**	**1,629.98**	**1,536.34**	**26,426.90**
Balancing Account	Total Cost	95,589.32	97,783.28	101,717.52	88,180.77	91,381.12	101,311.13	249,376.50	111,429.25	108,354.90	110,425.81	110,846.32	108,664.49	1,375,060.41
	NPC Application Fees Collected		(35.00)	(374,490.00)	(204,955.00)	(176,800.00)	(200,440.00)	(203,830.00)	(200,260.00)	(186,930.00)	(194,620.00)	(211,670.00)	(189,650.00)	(2,143,680.00)
	Monthly Net Balance >	**95,589.32**	**97,748.28**	**(272,772.48)**	**(116,774.23)**	**(85,418.88)**	**(99,128.87)**	**45,546.50**	**(88,830.75)**	**(78,575.10)**	**(84,194.19)**	**(100,823.68)**	**(80,985.51)**	**(768,619.59)**
	Cumulative Monthly Balance >	**95,589.32**	**193,337.60**	**(79,434.88)**	**(196,209.11)**	**(281,627.99)**	**(380,756.86)**	**(335,210.36)**	**(424,041.11)**	**(502,616.21)**	**(586,810.40)**	**(687,634.08)**	**(768,619.59)**	

	2022 Month:	1	2	3	4	5	6	7	8	9	10	11	12	2022 Total
Outside Services Costs	Customer Call and Email Support	18,400.00	16,040.00	(2,507.00)	38,507.50	14,637.50	16,637.50	17,017.50	14,950.00	20,210.50	19,048.75	-	37,097.50	210,039.75
	Software	30,500.50	30,500.50	30,500.50	30,500.50	30,500.50	77,488.50	377,794.70						607,785.70
	Application Processing and Labor	60,479.38	59,329.00	50,530.00	54,992.69	59,861.56	58,077.44	58,095.06	108,653.00	83,869.00	83,316.00	3,210.00	173,115.00	853,528.13
	Monthly Total Outside Services >	**109,379.88**	**105,869.50**	**78,523.50**	**124,000.69**	**104,999.56**	**152,203.44**	**452,907.26**	**123,603.00**	**104,079.50**	**102,364.75**	**3,210.00**	**210,212.50**	**1,671,353.58**
Utility Costs	Internal Labor/Overhead	675.10	754.54	2,254.18	1,447.15	1,134.02	767.96	730.51	1,093.98	772.35	813.00	673.70	689.86	11,806.35
	Expense Report	9.80	10.09	10.09	10.00									39.98
	Monthly Total Utility Admin >	**684.90**	**764.63**	**2,264.27**	**1,457.15**	**1,134.02**	**767.96**	**730.51**	**1,093.98**	**772.35**	**813.00**	**673.70**	**689.86**	**11,846.33**
Balancing Account	Total Cost	110,064.78	106,634.13	80,787.77	125,457.84	106,133.58	152,971.40	453,637.77	124,696.98	104,851.85	103,177.75	3,883.70	210,902.36	1,683,199.91
	NPC Application Fees Collected	(141,090.00)	(150,300.00)	(205,040.00)	(210,360.00)	(203,730.00)	(230,117.86)	(215,490.00)	(282,150.00)	(240,200.00)	(233,930.00)	(200,240.00)	(208,780.00)	(2,521,427.86)
	Monthly Net Balance >	**(31,025.22)**	**(43,665.87)**	**(124,252.23)**	**(84,902.16)**	**(97,596.42)**	**(77,146.46)**	**238,147.77**	**(157,453.02)**	**(135,348.15)**	**(130,752.25)**	**(196,356.30)**	**2,122.36**	**(838,227.95)**
	Cumulative Monthly Balance >	**(799,644.81)**	**(843,310.68)**	**(967,562.91)**	**(1,052,465.07)**	**(1,150,061.49)**	**(1,227,207.95)**	**(989,060.18)**	**(1,146,513.20)**	**(1,281,861.35)**	**(1,412,613.60)**	**(1,608,969.90)**	**(1,606,847.54)**	

	2023 Month:	1	2	3	4	5	6	7	8	9	10	11	12	2023 Total
Outside Services Costs	Customer Call and Email Support	18,400.00	19,080.00	17,320.00	19,035.00	17,320.00	18,425.00	62.50	36,320.00	18,562.50	17,485.00	20,937.50	17,380.00	220,327.50
	Software						44,635.00	471,921.00	-	-	-	122,640.00	87,000.00	726,196.00
	Application Processing and Labor	90,853.00	90,853.00	90,853.00	98,654.00	94,727.00	94,763.00	99,676.00	99,676.00	99,676.00	214,436.00	117,181.00	291,282.00	1,482,630.00
	IT Support							609.00						609.00
	Monthly Total Outside Services >	**109,253.00**	**109,933.00**	**108,173.00**	**117,689.00**	**112,047.00**	**157,823.00**	**572,268.50**	**135,996.00**	**118,238.50**	**231,921.00**	**260,758.50**	**395,662.00**	**2,429,762.50**
Utility Costs	Internal Labor/Overhead	3,460.13	2,589.04	7,311.81	3,462.97	3,227.39	3,122.41	3,208.39	4,634.76	2,843.33	2,557.48	2,393.04	1,953.18	40,763.93
	Expense Report											535.50		535.50
	Monthly Total Utility Admin >	**3,460.13**	**2,589.04**	**7,311.81**	**3,462.97**	**3,227.39**	**3,122.41**	**3,208.39**	**4,634.76**	**2,843.33**	**2,557.48**	**2,928.54**	**1,953.18**	**41,299.43**
Balancing Account	Total Cost	112,713.13	112,522.04	115,484.81	121,151.97	115,274.39	160,945.41	575,476.89	140,630.76	121,081.83	234,478.48	263,687.04	397,615.18	2,471,061.93
	NPC Application Fee Collected	(182,960.00)	(180,128.25)	(219,681.75)	(218,030.00)	(261,415.39)	(278,310.00)	(294,540.00)	(329,800.00)	(275,600.00)	(292,660.00)	(285,720.00)	(194,270.00)	(3,013,115.39)
	Sierra Journal Corrections/ Adjustments [1]	(7,056.00)	6,888.00	252.00	(84.00)		(6,636.00)	6,552.00	84.00					-
	Monthly Net Balance >	**(77,302.87)**	**(60,718.21)**	**(103,944.94)**	**(96,962.03)**	**(146,141.00)**	**(124,000.59)**	**287,488.89**	**(189,085.24)**	**(154,518.17)**	**(58,181.52)**	**(22,032.96)**	**203,345.18**	**(542,053.46)**
	Cumulative Monthly Balance >	**(1,684,150.41)**	**(1,744,868.62)**	**(1,848,813.56)**	**(1,945,775.59)**	**(2,091,916.59)**	**(2,215,917.18)**	**(1,928,428.29)**	**(2,117,513.53)**	**(2,272,031.70)**	**(2,330,213.22)**	**(2,352,246.18)**	**(2,148,901.00)**	

[1] Sierra adjustments are corrections made to relocate the fees to the appropriate Company when an applicant charges their fee to the wrong balancing account.

Nevada Power
Summary of Rule 15 Interconnection Application Processing Costs and Application Fees
Account 254192

	2024 Month:	1	2	3	4	5	6	7	8	9	10	11	12	2024 Total
Outside Services	Customer Call and Email Support		38,166.50	34,718.22	19,038.00	19,100.00	19,009.50	18,439.50	59,606.58	37,837.78	37,525.14	(77,525.14)		205,916.08
	Software						47,656.31	397,065.17						444,721.48
	Application Processing and Labor (Old)	233,280.66	699,833.06	(287,758.00)	212,849.00	212,245.50	199,230.00	170,026.00	162,570.00	162,572.00	147,472.00	81,123.00	117,512.00	2,110,955.22
	Application Processing and Labor (New)											113,626.60	38,608.36	152,234.96
	Application Technical Advisory Services											19,706.13	6,646.05	26,352.18
	Monthly Total Outside Services >	**233,280.66**	**737,999.56**	**(253,039.78)**	**231,887.00**	**231,345.50**	**265,895.81**	**585,530.67**	**222,176.58**	**200,409.78**	**184,997.14**	**136,930.59**	**162,766.41**	**2,940,179.92**
Utility Costs	Internal Labor/Overhead	11,043.76	8,865.94	8,433.66	8,224.24	7,674.80	6,656.41	10,451.45	7,220.94	6,808.35	8,020.06	8,302.65	22,231.01	113,933.27
	Expense Report								860.43		1,394.06		223.50	2,477.99
	Travel	271.78	1,179.54							3,038.96				4,490.28
	Monthly Total Utility Admin >	**11,315.54**	**10,045.48**	**8,433.66**	**8,224.24**	**7,674.80**	**6,656.41**	**10,451.45**	**8,081.37**	**9,847.31**	**9,414.12**	**8,302.65**	**22,454.51**	**120,901.54**
Balancing Account	Total Cost	244,596.20	748,045.04	(244,606.12)	240,111.24	239,020.30	272,552.22	595,982.12	230,257.95	210,257.09	194,411.26	145,233.24	185,220.92	3,061,081.46
	NPC Application Fees Collected	(175,076.00)	(169,225.01)	(145,656.00)	(171,203.00)	(173,825.00)	(145,924.00)	(176,829.55)	(165,262.45)	(153,669.00)	(169,710.90)	(117,607.00)	(107,100.00)	(1,871,087.91)
	Cumulative Monthly Balance >	**69,520.20**	**648,340.23**	**258,078.11**	**326,986.35**	**392,181.65**	**518,809.87**	**937,962.44**	**1,002,957.94**	**1,059,546.03**	**1,084,246.39**	**1,111,872.63**	**1,189,993.55**	**1,189,993.55**

	2025 Month:	Estimate 1	Estimate 2	Estimate 3	Estimate 4	Estimate 5	Estimate 6	Estimate 7	Estimate 8	Estimate 9	Estimate 2025 Total
Outside Services	Software						49,086.00	408,977.13			458,063.12
	Application Processing and Labor (New)	107,377.62	107,377.62	107,377.62	107,377.62	107,377.62	107,377.62	107,377.62	107,377.62	107,377.62	966,398.61
	Application Technical Advisory Services	21,622.38	21,622.38	21,622.38	21,622.38	21,622.38	21,622.38	21,622.38	21,622.38	21,622.38	194,601.39
	Monthly Total Outside Services >	**129,000.00**	**129,000.00**	**129,000.00**	**129,000.00**	**129,000.00**	**178,086.00**	**537,977.13**	**129,000.00**	**129,000.00**	**1,619,063.12**
Utility Costs	Internal Labor/Overhead	46,022.67	46,022.67	46,022.67	46,022.67	46,022.67	46,022.67	46,022.67	46,022.67	46,022.67	414,204.00
	Expense Report										
	Travel										
	Monthly Total Utility Admin >	**46,022.67**	**46,022.67**	**46,022.67**	**46,022.67**	**46,022.67**	**46,022.67**	**46,022.67**	**46,022.67**	**46,022.67**	**414,204.00**
Balancing Account	Total Cost	175,022.67	175,022.67	175,022.67	175,022.67	175,022.67	224,108.67	583,999.79	175,022.67	175,022.67	2,033,267.12
	NPC Application Fee Collected	(170,160.08)	(170,160.08)	(170,160.08)	(170,160.08)	(170,160.08)	(170,160.08)	(170,160.08)	(170,160.08)	(170,160.08)	(1,531,440.75)
	Cumulative Monthly Balance >	**1,194,856.13**	**1,199,718.72**	**1,204,581.30**	**1,209,443.88**	**1,214,306.47**	**1,268,255.05**	**1,682,094.76**	**1,686,957.34**	**1,691,819.92**	**1,691,819.92**

EXHIBIT BELCHER-DIRECT-3

Nevada Power
External Contracting Costs and Allocations
Account 254192

Annual Software License Fee

	2025	2026	2027	2028
Est. Annual Cost	$518,905	$539,661	$561,248	$583,698
Est. True-up	$58,474	$60,813	$63,245	$65,775
Online Solar/Storage Calculator	$146,000	$151,840	$157,914	$164,230
	$723,379	$752,314	$782,407	$813,703
Cost Allocation				
Net Metering SPPC	$115,741	$120,370	$125,185	$130,192
Net Metering NPC	$607,638	$631,944	$657,222	$683,511
Clean Energy Solar SPPC	$0	$0	$0	$0
Clean Energy Solar NPC	$0	$0	$0	$0
Clean Energy EV SPPC	$0	$0	$0	$0
Clean Energy EV NPC	$0	$0	$0	$0
Clean Energy SS SPPC	$0	$0	$0	$0
Clean Energy SS NPC	$0	$0	$0	$0
Clean Energy LS SPPC	$0	$0	$0	$0
Clean Energy LS NPC	$0	$0	$0	$0
	$723,379	$752,314	$782,407	$813,703

First Level Call Support & Application Processing & Technical Advisory Services

	2025	2026	2027	2028
Est. Annual Cost	$1,800,000	$1,854,000	$1,909,620	$1,966,909
	$1,800,000	$1,854,000	$1,909,620	$1,966,909
Cost Allocation				
Net Metering SPPC	$288,000	$296,640	$305,539	$314,705
Net Metering NPC	$1,512,000	$1,557,360	$1,604,081	$1,652,203
Clean Energy Solar SPPC	$0	$0	$0	$0
Clean Energy Solar NPC	$0	$0	$0	$0
Clean Energy EV SPPC	$0	$0	$0	$0
Clean Energy EV NPC	$0	$0	$0	$0
Clean Energy SS SPPC	$0	$0	$0	$0
Clean Energy SS NPC	$0	$0	$0	$0
Clean Energy LS SPPC	$0	$0	$0	$0
Clean Energy LS NPC	$0	$0	$0	$0
	$1,800,000	$1,854,000	$1,909,620	$1,966,909

EXHIBIT BELCHER-DIRECT-4

Nevada Power
Base Application Fee Calculation
Account 254192

Line		2025 Q4	2026	2027	2028 Q1-Q3
2	Estimated Volume	4290	17159	17159	12869
3	Application Fee	$ 158.00	$ 158.00	$ 158.00	$ 158.00
5	Application Fee Revenue	$ (677,780.50)	$ (2,711,122.00)	$ (2,711,122.00)	$ (2,033,341.50)
7	Utility Admn (Labor & Labor Overheads)				
8	> Other Program Support	$ 148,068.00	$ 610,040.16	$ 628,341.36	$ 485,393.70
10	Contracted Processing Services				
11	> Customer Call and Email Support				
12	> Application Processing (Old)				
13	> Application Processing (New)	$ 322,132.87	$ 1,327,187.42	$ 1,367,003.04	$ 1,056,009.85
14	> Technical Advisory Services	$ 64,867.13	$ 267,252.58	$ 275,270.16	$ 212,646.20
16	Software				
17	> Software License Fees & Online Educational Calculators		$ 471,805.02	$ 485,959.17	$ 375,403.46
19	Total Cost	$ 535,068.00	$ 2,676,285.18	$ 2,756,573.73	$ 2,129,453.21
21	Annual Balance (Revenue - Fee)	$ (142,712.50)	$ (34,836.82)	$ 45,451.73	$ 96,111.71
23	Carry Over to next year		$ (142,712.50)	$ (177,549.32)	$ (132,097.59)
25	Grand Total	$ (142,712.50)	$ (177,549.32)	$ (132,097.59)	$ (35,985.88)
28			Proposed App Fee		$ 158.00

Nevada Power
Application Fee with Under-Collection Amortization
Account 254192

	2024	2025 Q1-Q3	2025 Q4	2026	2027	2028 Q1-Q3
Estimated Volume	15723	12869	4290	17159	17159	12869
Application Fee	$ 119.00	$ 119.00	$ 189.00	$ 189.00	$ 189.00	$ 189.00
Application Fee Revenue	$ (1,871,037.00)	$ (1,531,440.75)	$ (810,762.75)	$ (3,243,051.00)	$ (3,243,051.00)	$ (2,432,288.25)
Utility Admn (Labor & Labor Overheads)						
> Other Program Support	$ 120,901.54	$ 414,204.00	$ 148,068.00	$ 579,140.16	$ 596,514.36	$ 460,807.35
Contracted Processing Services						
> Customer Call and Email Support	$ 205,916.08					
> Application Processing (Old)	$ 2,110,955.22					
> Application Processing (New)	$ 152,234.96	$ 966,398.61	$ 322,132.87	$ 1,327,187.42	$ 1,367,003.04	$ 1,056,009.85
> Technical Advisory Services	$ 26,352.18	$ 194,601.39	$ 64,867.13	$ 267,252.58	$ 275,270.16	$ 212,646.20
Software						
> Software License Fees & Online Educational Calculators	$ 444,721.48	$ 458,063.12		$ 471,805.02	$ 485,959.17	$ 375,403.46
Total Cost	$ 3,061,081.46	$ 2,033,267.12	$ 535,068.00	$ 2,645,385.18	$ 2,724,746.73	$ 2,104,866.85
Annual Balance (Revenue - Fee)	$ 1,190,044.46	$ 501,826.37	$ (275,694.75)	$ (597,665.82)	$ (518,304.27)	$ (327,421.40)
Carry Over to next year		$ 1,190,044.46	$ 1,691,870.83	$ 1,416,176.08	$ 818,510.26	$ 300,206.00
Grand Total	$ 1,190,044.46	$ 1,691,870.83	$ 1,416,176.08	$ 818,510.26	$ 300,206.00	$ (27,215.40)
				Proposed App Fee		$ 189.00

Nevada Power
Application Fee with Under-Collection Amortization (Unused Funds Offsetting)
Account 254192

	2024	2025 Q1-Q3	2025 Q4	2026	2027	2028 Q1-Q3
Estimated Volume	15723	12869	4290	17159	17159	12869
Application Fee	$ 119.00	$ 119.00	$ 179.00	$ 179.00	$ 179.00	$ 179.00
Application Fee Revenue	$ (1,871,037.00)	$ (1,531,440.75)	$ (767,865.25)	$ (3,071,461.00)	$ (3,071,461.00)	$ (2,303,595.75)
Utility Admn (Labor & Labor Overheads)						
> Other Program Support	$ 120,901.54	$ 414,204.00	$ 148,068.00	$ 579,140.16	$ 596,514.36	$ 460,807.35
Contracted Processing Services						
> Customer Call and Email Support	$ 205,916.08					
> Application Processing (Old)	$ 2,110,955.22					
> Application Processing (New)	$ 152,234.96	$ 966,398.61	$ 322,132.87	$ 1,327,187.42	$ 1,367,003.04	$ 1,056,009.85
> Technical Advisory Services	$ 26,352.18	$ 194,601.39	$ 64,867.13	$ 267,252.58	$ 275,270.16	$ 212,646.20
Software						
> Software License Fees & Online Educational Calculators	$ 444,721.48	$ 458,063.12		$ 471,805.02	$ 485,959.17	$ 375,403.46
Total Cost	$ 3,061,081.46	$ 2,033,267.12	$ 535,068.00	$ 2,645,385.18	$ 2,724,746.73	$ 2,104,866.85
Annual Balance (Revenue - Fee)	$ 1,190,044.46	$ 501,826.37	$ (232,797.25)	$ (426,075.82)	$ (346,714.27)	$ (198,728.90)
Undeliverable Refund + Unspent NVE refund processing labor	$ (501,387.80)					
Carry Over to next year		$ 688,656.66	$ 1,190,483.03	$ 957,685.78	$ 531,609.96	$ 184,895.70
Grand Total	$ 688,656.66	$ 1,190,483.03	$ 957,685.78	$ 531,609.96	$ 184,895.70	$ (13,833.20)
				Proposed App Fee		$ 179.00

Nevada Power
Current Application Fee
Account 254192

	2024	2025 Q1-Q3	2025 Q4	2026	2027	2028 Q1-Q3
Estimated Volume	15723	12869	4290	17159	17159	12869
Application Fee	$ 119.00	$ 119.00	$ 119.00	$ 119.00	$ 119.00	$ 119.00
Application Fee Revenue	$ (1,871,037.00)	$ (1,531,440.75)	$ (510,480.25)	$ (2,041,921.00)	$ (2,041,921.00)	$ (1,531,440.75)
Utility Admn (Labor & Labor Overheads)						
> Other Program Support	$ 120,901.54	$ 414,204.00	$ 148,068.00	$ 579,140.16	$ 596,514.36	$ 460,807.35
Contracted Processing Services						
> Customer Call and Email Support	$ 205,916.08					
> Application Processing (Old)	$ 2,110,955.22					
> Application Processing (New)	$ 152,234.96	$ 966,398.61	$ 322,132.87	$ 1,327,187.42	$ 1,367,003.04	$ 1,056,009.85
> Technical Advisory Services	$ 26,352.18	$ 194,601.39	$ 64,867.13	$ 267,252.58	$ 275,270.16	$ 212,646.20
Software						
> Software License Fees & Online Educational Calculators	$ 444,721.48	$ 458,063.12		$ 471,805.02	$ 485,959.17	$ 375,403.46
Total Cost	$ 3,061,081.46	$ 2,033,267.12	$ 535,068.00	$ 2,645,385.18	$ 2,724,746.73	$ 2,104,866.85
Annual Balance (Revenue - Fee)	$ 1,190,044.46	$ 501,826.37	$ 24,587.75	$ 603,464.18	$ 682,825.73	$ 573,426.10
Carry Over to next year		$ 1,190,044.46	$ 1,721,870.83	$ 1,746,458.58	$ 2,349,922.76	$ 3,032,748.50
Grand Total	$ 1,190,044.46	$ 1,691,870.83	$ 1,746,458.58	$ 2,349,922.76	$ 3,032,748.50	$ 3,606,174.60
				Proposed App Fee		$ 119.00

Nevada Power
Sierra Application Fee
Account 254192

	2024	2025 Q1-Q3	2025 Q4	2026	2027	2028 Q1-Q3
Estimated Volume	15723	12869	4290	17159	17159	12869
Application Fee	$ 119.00	$ 119.00	$ 184.00	$ 184.00	$ 184.00	$ 184.00
Application Fee Revenue	$ (1,871,037.00)	$ (1,531,440.75)	$ (789,314.00)	$ (3,157,256.00)	$ (3,157,256.00)	$ (2,367,942.00)
Utility Admn (Labor & Labor Overheads)						
> Other Program Support	$ 120,901.54	$ 414,204.00	$ 148,068.00	$ 579,140.16	$ 596,514.36	$ 460,807.35
Contracted Processing Services						
> Customer Call and Email Support	$ 205,916.08					
> Application Processing (Old)	$ 2,110,955.22					
> Application Processing (New)	$ 152,234.96	$ 966,398.61	$ 322,132.87	$ 1,327,187.42	$ 1,367,003.04	$ 1,056,009.85
> Technical Advisory Services	$ 26,352.18	$ 194,601.39	$ 64,867.13	$ 267,252.58	$ 275,270.16	$ 212,646.20
Software						
> Software License Fees & Online Educational Calculators	$ 444,721.48	$ 458,063.12		$ 471,805.02	$ 485,959.17	$ 375,403.46
Total Cost	$ 3,061,081.46	$ 2,033,267.12	$ 535,068.00	$ 2,645,385.18	$ 2,724,746.73	$ 2,104,866.85
Annual Balance (Revenue - Fee)	$ 1,190,044.46	$ 501,826.37	$ (254,246.00)	$ (511,870.82)	$ (432,509.27)	$ (263,075.15)
Carry Over to next year		$ 1,190,044.46	$ 1,721,870.83	$ 1,467,624.83	$ 955,754.01	$ 523,244.75
Grand Total	$ 1,190,044.46	$ 1,691,870.83	$ 1,467,624.83	$ 955,754.01	$ 523,244.75	$ 260,169.60

Proposed App Fee	$ 184.00

EXHIBIT BELCHER-DIRECT-5

EXHIBIT BELCHER-DIRECT-5

FILED UNDER CONFIDENTIAL SEAL

EXHIBIT BELCHER-DIRECT-6

RULE NO. 15

GENERATING FACILITY INTERCONNECTIONS

D. APPLICATION AND INTERCONNECTION PROCESS

1. APPLICATION PROCESS

a. Upon request, the Utility will provide information and documents (such as the pro forma interconnection and operating agreement and the Application, technical requirements, specifications, listing of Certified Equipment, application fee information, applicable rate schedules and Metering requirements) in response to a potential Applicant's inquiry. Unless otherwise agreed upon, all such information will normally be sent to an Applicant within five (5) business days following the initial request from the Applicant. The Utility will establish an individual representative as the single point of contact for the Applicant, but may allocate responsibilities among its staff to best coordinate the Interconnection of an Applicant's Generating Facility. For Net Metering Systems, the Utility will send a description of the procedures by which a Customer may interconnect with the Utility and a copy of the standard net metering contract with the application form.

b. Applicant Completes an Application. All Applicants shall be required to complete and file an Application and supply any relevant additional information requested by Utility. The filing must include the completed Application, a fee for processing the Application and performing the Initial Review to be completed by the Utility pursuant to Section D.1.c. The application fee shall vary with the type of service that will be provided to the customer account to which the proposed Generating Facility will be interconnected as indicated in the following table:

Generating Facility Capacity	Initial Review Fee	Supplemental Review Fee
<= 1 MW	$189	None*
All Others	Actual Costs Incurred*	Actual Costs Incurred*

(I)

* If an interconnection study is required, pursuant to Section D.1.d, Producer will be charged the actual costs of a Supplemental Review Study pursuant to Section D.1.d.

(Continued)

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

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, CHRISTOPHER BELCHER, 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: February 14, 2025

CHRISTOPHER BELCHER

MARIYA COLEMAN

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 25-02____
2025 General Rate Case

Prepared Direct Testimony of

Mariya Coleman

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

A. My name is Mariya Coleman. I am the Vice President of Corporate Insurance for Berkshire Hathaway Energy Company, Nevada Power Company d/b/a NV Energy ("Nevada Power" or the "Company") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra," and together with Nevada Power, the "Companies"). My business address is 2755 E. Cottonwood Parkway in Salt Lake City, Utah. I am filing testimony on behalf of Nevada Power.

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

A. I joined the Companies as a Risk Analyst in 2010 and worked in Corporate Insurance through 2014. From 2014 through 2017, I was the Manager of Corporate Insurance. From 2017 through 2022, I was the Director of Corporate Insurance. In 2023, I was named Vice President of Corporate Insuance and Claims. I have a Bachelor of Science in Finance from University of Nevada, Las Vegas, and a Master's in Business Administration from University of Nevada, Las Vegas. I completed the Master's in Renewable Engineering Certificate program from

Nevada Power Company
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University of Nevada, Reno, in 2014. A complete statement of my qualifications is set forth in **Exhibit Coleman-Direct-1**.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES.

A. As Vice President of Corporate Insurance and Claims, I am responsible for the acquisition and management of all corporate insurance programs, excluding benefits-related plans. Additionally, I am responsible for the day-to-day claims oversight.

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

A. Yes, I have testified previously before the Commission. My most recent general rate case testimony was in Sierra's 2024 general rate cases, Docket Nos. 24-02026 and 24-02027.

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

A. I support and explain the reasonableness of the changes to three categories of the annual insurance costs reflected on Schedule H-CERT-22. Schedule H-CERT-22 shows that Nevada Power's allocable share of the annualized cost of property insurance has increased from $986,000 (as recorded on September 30, 2024) to $1,112,000 (estimated as of February 28, 2025). Nevada Power's allocable share of the annual cost of excess liability insurance has increased from $14,726,000 (as recorded on September 30, 2024) to $18,439,000 (estimated as of February 28, 2025). The annual cost of fiduciary liability insurance is $45,000.

Nevada Power Company
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d/b/a NV Energy

6. Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY OTHER THAN YOUR STATEMENT OF QUALIFICATIONS?

A. No.

7. Q. PLEASE EXPLAIN THE INCREASE IN THE ANNUALIZED COST OF PROPERTY INSURANCE.

A. During the Certification Period (October 1, 2024 – February 28, 2025), the cost of property insurance increased, and Nevada Power's property values and exposures increased slightly relative to other insured assets. As a result, Nevada Power's allocated share of premium costs for property insurance increased. Property insurance rates have increased on a compounded basis for several years due to inflation, which is driving the increased cost of industry-wide claims experienced during this inflationary period. For example, Insurance Information Institute says that replacement costs for all property and casualty lines have increased 39.85 percent over Consumer Price Index increases.[1] The higher rates are now being applied to a larger inventory of property within Nevada Power, driving up Nevada Power's property insurance allocated costs.

8. Q. PLEASE EXPLAIN THE INCREASE IN THE ANNUALIZED COST OF LIABILITY INSURANCE.

A The increase in the annualized cost of excess liability insurance is primarily due to the increased cost of wildfire coverage and the Companies' purchase of stand-alone liability insurance for the exclusive benefit of the Companies. In previous years, the Companies secured these coverages exclusively through Berkshire Hathaway

[1] Sean Kevelighan, CEO & President, Insurance Information Institute, 2024 Policyholders' Conference: *2024 Economic and Insurance Market Conditions* at 7 (July 18, 2024).

Energy's ("BHE") company-wide program. In 2024, the Companies purchased stand-alone liability insurance to provide the Companies with $218.5 million in exclusive excess liability limits, of which $168.5 million can be used for wildfire claims.

9. Q. PLEASE PROVIDE CONTEXT FOR THE INCREASE OF EXCESS LIABILITY PREMIUMS.

A Due to prolonged drought conditions and increased development in wildland areas, wildfires across the western United States have proliferated in the last several years, and these fires have become larger and more destructive. This has resulted in significant increases in wildfire costs for utilities and an inability to acquire insurance at rates and coverage levels consistent with past premiums.

Some examples of the difficulties that utilities are experiencing regarding wildfire coverage include insurers increasing the price at which they will consider selling insurance covering claims from wildfire liability and reducing the amount of coverage that they will sell. The excess casualty market rate increased 107.6 percent since 2011, according to international brokerage firm Guy Carpenter,[2] and the appetite for insurance companies to sell wildfire insurance is decreasing. This is highlighted by Energy Insurance Mutual's reduction in wildfire limits over the last three years.[3] Energy Insurance Mutual is an exclusive mutualized insurance company for the gas and electric utility industry. In summary, insurers who historically would consider selling wildfire liability will no longer do so and are replaced in the insurance market by insurers who require much higher premiums.

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[2] GuyCarpenter, *Excess/Umbrella: State of the Market Summary*, at 26 (Nov. 2023).
[3] McGriff Energy, *Status Update:Wildfire Coverage for Utilities in 2024*, at 5.

The Companies used to exclusively participate in a shared liability coverage with other BHE businesses, but given the increase in exposure from recent events, it was prudent for the Companies to obtain coverage that is specifically allocated to just the Companies, as well as continuing to participate the shared policy program. This diversified approach allows the Companies to balance coverage and costs for its customers. . The shared liability coverage with other BHE entities provides the Companies with an insurance product at lower cost as compared to purely standalone policies. However, those shared policies have limitations to the extent that multiple claims are made in the same year from other BHE entities. Thus, the Companies determined that the current insurance allocation delivers customers the appropriate balance of cost and coverage in the current market conditions. Ultimately, the excess liability insurance increase the Companies experienced is not a one-time anomaly but is indicative of the high cost of obtaining excess liability coverage that ensures availability of coverage moving forward.

10. Q. DOES THE STATE OF NEVADA HAVE EXPOSURE TO THE RISK AND RELATED COSTS OF WILDFIRE?

A. Yes. As discussed in the Companies' Natural Disaster Protection Plan filed in Docket No. 23-03003, the Companies' service territories include tier areas of high and elevated wildfire risk.

11. Q. HOW DID THE COMPANIES DETERMINE THE LEVEL OF REASONABLE LIABILITY INSURANCE COVERAGE?

A. The Companies evaluated wildfire claims results from the western United States and purchased available insurance limits that were offered by the insurance companies. Maintaining insurance is a necessary component of operating a utility and managing the risks associated with the business. The Companies endeavor to maintain insurance at sufficient levels to avoid the negative and volatile impact of claims on customer rates. Unfortunately, in the event of a catastrophic wildfire, liabilities can and likely would exceed the insurance coverage limits now available. Chubb's 2024 Liability Large Loss Report demonstrates utilities are underinsured compared to the losses they can experience.[4] The Companies are continuing to try and address this by evaluating available insurance products that can balance coverage with costs, and have made a recent filing seeking an incremental self-insurance alternative to increase the Companies' wildfire coverage to an amount commensurate with the risk they face.

12. Q. HOW DOES THE COMPANY ALLOCATE EXCESS LIABILITY INSURANCE PREMIUMS BETWEEN NEVADA POWER AND SIERRA?

A. Excess liability insurance is currently allocated as 27.92 percent to Sierra and 69.01 percent to Nevada Power.[5] The wildfire liability insurance premiums within the excess liability program are allocated separately as 76 percent to Sierra and 24 percent to Nevada Power. The allocation is based on a multi-factor objectively verifiable methodology.

In Sierra's last rate case, Docket Nos. 24-02026 and 24-02027, the Commission affirmed the Company's proposed allocation methodology, but directed Sierra and Nevada Power to review differences in wildfire risk and exposure between Sierra and Nevada Power for purposes of allocating the excess liability insurance policies

[4] Chubb Bermuda, *Liability Limit Benchmark & Large Loss Profile by Industry Sector 2024: Navigating an ever-escalating liability landscape*, at 29 (May 2024).
[5] An additional allocation of 3.07 percent for excess liability insurance is made for Valmy Generating Station.

that include coverage for wildfire liability.[6] The portion of Companies' excess liability insurance policies that cover wildfire liability have been separately identified and are allocated as 76 percent to Sierra and 24 percent to Nevada Power, thereby addressing the Commission's request.

13. Q. PLEASE EXPLAIN WHY THE ANNUALIZED COST OF FIDUCIARY LIABILITY INSURANCE REMAINED STABLE.

A. The annual cost remains flat due to stable market rates for this specific type of insurance.

14. Q. ARE THE ANNUAL COSTS OF INSURANCE SHOWN ON SCHEDULE H-CERT-22 REFLECTIVE OF NEVADA POWER'S ONGOING ANNUAL INSURANCE COSTS?

A. Yes, they are.

15. Q. WILL SCHEDULE H-CERT-22 BE UPDATED FOR CERTIFICATION?

A Yes, the estimates in Schedule H-CERT-22 will be updated to include actuals as of February 28, 2025.

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

A. Yes, it does.

[6] Docket Nos. 24-02026 and 24-02027, *Modified Final Order*, at 111, ¶ 344.

EXHIBIT COLEMAN-DIRECT-1

QUALIFICATIONS OF WITNESS
Mariya Coleman
Vice President, Corporate Insurance and Claims
Berkshire Hathaway Energy
2755 E Cottonwood Pkwy Ste 300
Salt Lake City, UT 84121

EDUCATION

University of Nevada-Las Vegas, Lee Business School
M.B.A., Finance – 2010
University of Nevada-Las Vegas
B.S.B.A., Finance – 2008

PROFESSIONAL EXPERIENCE

Berkshire Hathaway Energy, Salt Lake City, UT
Vice President, Insurance and Claims, May 2023 – present
Director, Corporate Insurance, July 2017 – May 2023
Manager, Corporate Insurance, January 2015 – July 2017

- Direct the Corporate Insurance function for Berkshire Hathaway Energy Co. reporting directly to the Senior Vice President and General Counsel of BHE
- Responsible for $190 million global insurance program covering $132 billion in assets, $25 billion in revenue, 48,800 miles of natural gas pipelines and 23,600 employees world wide
- Manage NV Energy captive insurance subsidiary
- Coordinate with multiple business units the operating platforms to develop risk and insurance cost forecasts and allocation strategy
- Provide insurance related expertise for all major merger and acquisition activities
- Oversight of claims strategy and administration

NV Energy, Las Vegas, Nevada
Senior Analyst, September 2011– December 2015
Analyst, August 2010 – September 2011

- Supported the restructuring of coverage terms, limits and risk renteion levels generating annual premium spend savings in excess of $5 million vs. 2010 levels
- Participated in the Berkshire Hathaway Energy acquisition integration team
- Principal analyst on renewals of liability, property, worker's compensation and environmental insurance programs
- Provided expertise on contractual risk transfer to multiple Berkshire Hathaway Energy businesses and created a central standard for contractual terms
- Optimized risk reduction efforts within Power Generation team by recreating monthly reporting format for Risk Performance Metric
- Led 2011, 2013 and 2014 General Rate Case submission and testimony development for Corporate Insurance
- Provided industry accepted language improvements to insurance and indemnity provisions in major and minor agreements with counterparties

RELEVANT INDUSTRY/PROFESSIONAL INFORMATION

Graduate Certificate in Renewable Energy, University of Reno, 2014; Associate in Claims (AIC), 2015; Associate in Risk Management (ARM), 2013; Chartered Property Casualty Underwriter (CPCU), 2013; Leadership Henderson Grauduate, 2013; NV Chapter of Risk and Insurance Management Society Board, 2013-2015; AEGIS Loss Control Task Force, 2015-present; Energy Insurance Mutual Insurance Advisory Council 2021-present

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

<u>AFFIRMATION</u>

Pursuant to the requirements of NRS 53.045 and NAC 703.710, MARIYA COLEMAN, states that she 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 her knowledge and belief; and that if asked the questions appearing therein, her answers thereto would, under oath, be the same.

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

Date: February 14, 2025

Mariya Coleman

Mariya Coleman

STEPHEN MARCIANO

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 25-02___
2025 General Rate Case

Prepared Direct Testimony of

Stephen Marciano

Revenue Requirement

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

A. My name is Stephen Marciano. I am the Supervisor, Claims for Nevada Power Company d/b/a NV Energy ("Nevada Power" or the "Company") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and together with Nevada Power, the "Companies"). My business address is 6226 West Sahara Avenue, Las Vegas, Nevada. I am filing testimony on behalf of Nevada Power.

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

A. I have worked at the Company since July 2023, but I have worked in the claims and risk management industry for more than 20 years. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Marciano-Direct-1**.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS CLAIM SUPERVISOR.

A. As the Supervisor, Claims, my responsibilities include directing the Claims Department team of investigators in the resolution of both first- and third-party

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

claims. First-party claims occur when a third party causes damage to Company property and equipment. The Claims Department investigates and documents the cause of the damage along with identifying the responsible party. We then pursue the responsible party and/or their insurance company until collection is made, and all remedies have been exhausted. Third-party claims occur when the Company has caused damage or injury to a third party, and they have presented a claim against the Company.

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

A. Yes. I filed testimony in Sierra's electric general rate case ("GRC"), Docket No. 24-02026.

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

A. I support the costs included in plant in service related to claims.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibits:

Exhibit Marciano-Direct-1 Statement of Qualifications

7. Q. WHAT COSTS ARE INCLUDED IN PLANT IN SERVICE FOR CLAIMS PROJECTS?

A. Since the end of the Certification Period for Nevada Power's 2023 GRC until the end of the Test Period in this GRC, spanning June 1, 2023, through September 30, 2024, the Company experienced $496,732 in uncompensated costs to replace plant that was damaged by third parties.

The Company estimates that an additional $193,787 will be expended during the Certification Period for this case, October 1, 2024, through February 28, 2025. These costs reflect the costs incurred to replace damaged plant, over and above the amounts collected from the individual(s) responsible for damaging the plant.

These costs are included in the plant additions provided by Nevada Power witness Christina Hanshew in Exhibit Hanshew Direct-2 and Direct-3.

8. Q. PLEASE PROVIDE EXAMPLES OF THE TYPES OF CLAIMS THAT ARE INCLUDED IN THE COSTS BEING SOUGHT FOR RECOVERY IN THIS CASE.

A. The costs requested for recovery include any claim where the Company was unable to collect the full amount of the necessary repairs from the responsible party. Some examples of these costs include hit and run accidents (where the responsible party is never identified), car accidents where the responsible party's insurance is insufficient to cover the cost of repairing or replacing damaged equipment, and incidents for which the responsible party is uninsured and has no assets with which to pay the cost of repairing or replacing damaged equipment.

9. **Q. HOW DOES THE COMPANY PURSUE A RESPONSIBLE PARTY WHEN COMPANY EQUIPMENT IS DAMAGED OR DESTROYED?**

A. The Claims Department is notified when a third party causes damage to Company property and equipment. The cause of the damage is documented, and the responsible party is identified. After the repair work is completed and the costs are recorded, an invoice is generated and sent to the responsible party and/or their insurer. The claim is pursued with the responsible party and/or their insurance company until a collection is made. Should collection efforts fail, actions are filed against the responsible party in the appropriate court. The amounts requested for recovery represent the uncollected costs of repairing or replacing damaged Company property or equipment after the reasonable exhaustion of these remedies.

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

A. Yes.

EXHIBIT MARCIANO-DIRECT-1

STEPHEN S. MARCIANO
CLAIMS SUPERVISOR
NV Energy
6226 W. Sahara Avenue
Las Vegas, Nevada 89146
(702) 402-5172

My name is Stephen S. Marciano. My business address is 6226 W. Sahara Avenue, Las Vegas, Nevada. I am the Claims Supervisor for Nevada Power Company d/b/a NV Energy and for Sierra Pacific Power Company d/b/a NV Energy.

I have spent the majority of my career in the financial, risk management, and claims industry working primarily as Corporate Risk Manager for MGM Resorts International, and as a Multi-State Licensed Independent Property and Casualty Adjuster for various government/public entities at both City of Las Vegas and various Nevada and California counties. My previous experience also included credit and financial underwriting. My education includes a Bachelor of Science Degree in Business Administration from National American University .

I have been employed with NV Energy since July 2023, working as their Claims Supervisor.

I am responsible for securing the replacement of capital costs of plant that is damaged by third parties. These costs are associated with the replacement of capital assets where the company is unable to collect 100% from the responsible party. In addition, I work to mitigate financial exposures for claims brought against the company for property damages and injuries.

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

<u>AFFIRMATION</u>

Pursuant to the requirements of NRS 53.045 and NAC 703.710, STEPHEN MARCIANO, 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: February 14, 2025

Stephen Marciano

JENNY NAUGHTON

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 25-02___
2025 General Rate Case

Prepared Direct Testimony of

Jenny Naughton

Revenue Requirement

I. INTRODUCTION

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

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

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

A. I hold a Bachelor of Science degree in Finance, with an emphasis in Accounting from the University of Nevada, Reno. I joined the Companies in 2017 providing comprehensive rate analysis and support for their managed substantial energy use customers in the Major Accounts department. I later transitioned to the Regulatory Pricing and Economic Analysis department as a Pricing Specialist, assumed the role of Revenue Requirement and Federal Energy Regulatory Commission ("FERC") Manager in March 2022, and eventually my current position of Director, Regulatory Accounting and Reporting in May 2024. More details regarding my professional background and experience are set forth in **Exhibit Naughton-Direct-1**.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR OF REGULATORY ACCOUNTING AND REPORTING.

A. As Director, Regulatory Accounting and Reporting, my responsibilities include the oversight of the Companies' revenue requirement calculation in General Rate Cases ("GRC") and regulatory earned rate of return calculations, as well as the preparation of the fuel and purchased power recovery rates and various deferred energy mechanisms. I also oversee the revenue accounting team, which is responsible for the revenue reporting and analysis for the Companies. Additionally, I am responsible for the completion of various Public Utilities Commission of Nevada ("Commission") and FERC reporting requirements.

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

A. Yes. I have previously testified before the Commission in several dockets, which are listed in **Exhibit Naughton-Direct-1**. Most recently, I filed testimony in Sierra's electric and gas GRCs, Docket Nos. 24-02026 and 24-02027, respectively, as well as Nevada Power and Sierra's joint energy supply plan in Docket No. 24-05041.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to address the following:

- In sections III through XII, I sponsor the calculations for specified Statements and Schedules, listed below in the section order, as discussed in the testimony that follows;
- In section XIII, I discuss the Company's inclusion of Construction Work in Progress ("CWIP") for Greenlink West and Greenlink North (together "Greenlink") in its requested revenue requirement and the rate impact analysis as required in the Order from Docket No. 24-05041; and
- In section XIV, I discuss the Company's request to establish a regulatory asset for any decrease in revenue from customers that qualify and enroll in the Company's proposed low-income tariff.

Statements and Schedules

III. Statement H, Statement H CERT and Statement H ECIC

- Statement H – Summary of Results of Operations Before and After Rate Adjustment for the Certification Period ended February 28, 2025, and the Expected Change in Circumstance ("ECIC") Period ending September 12, 2025.
- Statement H CERT – Summary of Results of Operations Before and After Rate Adjustment for the Certification Period ended February 28, 2025.
- Statement H ECIC – Summary of Results of Operations Before and After Rate Adjustment for the ECIC Period ending September 12, 2025.

IV. Schedule H-1 CERT

- Schedule H-1 CERT– Detail of Certification Adjustments and Tax Effects as Set Forth in Statement H.

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V. Certification Schedules H-CERT-02 through H-CERT-07

- Schedule H-CERT-02 – Present Rate Revenue Reconciliation for the Test Period ended September 30, 2024, and for the Certification Period ended February 28, 2025.
- Schedule H-CERT-03 – Fuel & Purchased Power Expense Annualization for the Test Period ended September 30, 2024, and for the Certification Period ended February 28, 2025.
- Schedule H-CERT-04 – Cash Working Capital Calculation Before & After Rate Adjustment for the Test Period ended September 30, 2024, and for the Certification Period ended February 28, 2025.
- Schedule H-CERT-05 – Mill Tax for the Test Period ended September 30, 2024, and for the Certification Period ended February 28, 2025.
- Schedule H-CERT-06 – Interest Synchronization for the Test Period ended September 30, 2024, and for the Certification Period ended February 28, 2025.
- Schedule H-CERT-07 – Uncollectible Accounts Expense for the Test Period ended September 30, 2024, and for the Certification Period ended February 28, 2025.

VI. Schedule H-1 ECIC

- Schedule H-1 ECIC – Detail of ECIC Adjustments and Tax Effects as Set Forth in Statement H - ECIC.

VII. ECIC Schedules H-ECIC-04 through H-ECIC-07

- Schedule H-ECIC-04 – Cash Working Capital Calculation Before & After Rate Adjustment for the ECIC Period ending September 12, 2025.
- Schedule H-ECIC-05 – Mill Tax for the ECIC Period ending September 12, 2025.

- Schedule H-ECIC-06 – Interest Synchronization for the ECIC Period ending September 12, 2025.
- Schedule H-ECIC-07 – Uncollectible Accounts Expense for the ECIC Period ending September 12, 2025.

VIII. Schedule H-CERT-01 ECIC

- Schedule H-CERT-01 ECIC – Summary of Certification Adjustments for the Certification Period ended February 28, 2025, and ECIC Adjustments for the ECIC Period ending September 12, 2025.

IX. ECIC Schedule H-2 Unbundled Revenue Requirement

- Schedule H-2 – Unbundled Revenue Requirement for the Certification Period ended February 28, 2025, and the ECIC Period ending September 12, 2025.

X. Statement I

- Statement I – Summary of Results of Operations Before and After Rate Adjustment as Adjusted through the Certification Period ended February 28, 2025, and the ECIC Period ending September 12, 2025.

XI. H-CERT Schedules Related to Payroll

- H-CERT-17 – Payroll, Benefits & Pension Expense for the Test Period ended September 30, 2024, and for the Certification Period ended February 28, 2025.
- H-CERT-34 – Natural Disaster Protection Plan ("NDPP") Payroll Expense for the Test Period ended September 30, 2024, and for the Certification Period ended February 28, 2025.

XII. H-CERT Schedules Related to Existing Regulatory Assets and Liabilities, New Regulatory Assets and Liabilities, and Additional Certification Adjustments

- H-CERT-20 – Docket No. 21-06001 Incremental 2021 Triennial Resource Plan Costs Regulatory Asset for the Test Period ended September 30, 2024, and for the Certification Period ended February 28, 2025.

- H-CERT-21 – Miscellaneous Adjustments to Test Period Expenses.
- H-CERT-24 – Docket No. 22-06014 Incremental GRC Costs Regulatory Asset the Test Period ended September 30, 2024, and for the Certification Period ended February 28, 2025.
- H-CERT-25 – Docket No. 24-05041 Incremental 2024 Integrated Resource Plan Costs Regulatory Asset for the Test Period ended September 30, 2024, and for the Certification Period ended February 28, 2025.
- H-CERT-32 – Flex Pay Program Implementation Costs Regulatory Asset for the Test Period ended September 30, 2024, and for the Certification Period ended February 28, 2025.
- H-CERT-33 – Reset of Previously Approved Amortizations for the Test Period ended September 30, 2024, and for the Certification Period ended February 28, 2025.
- H-CERT-35 – NDPP Regulatory Asset for the Test Period ended September 30, 2024, and for the Certification Period ended February 28, 2025.
- H-CERT-36 – Business Transformation Stranded Net Book Value ("NBV") Deferred Debit ended September 30, 2024, and for the Certification Period ended February 28, 2025.
- H-CERT-37 – Net Energy Metering ("NEM") AB405 Deferred Debit ended September 30, 2024, and for the Certification Period ended February 28, 2025.
- H-CERT-38 – Reset of Previously Approved Amortizations for the Test Period ended September 30, 2024, and for the Certification Period ended February 28, 2025.
- H-CERT-39 – Inclusion of the Deferred Portion of Reid Gardner Battery Energy Storage System ("RG BESS") for the Test Period ended September 30, 2024.

- H-CERT-40 – Docket No. 23-06008 Depreciation Study Costs Regulatory Asset for the Test Period ended September 30, 2024, and for the Certification Period ended February 28, 2025.
- H-CERT-41 – Regional Transmission Organization ("RTO") Establishment Costs Regulatory Asset for the Test Period ended September 30, 2024, and for the Certification Period ended February 28, 2025.

Other Topics

XIII. Greenlink CWIP in Rate Base

XIV. Regulatory Asset Treatment for Low-Income Program

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibits:

Exhibit Naughton-Direct-1 Statement of Qualifications

Exhibit Naughton-Direct-2 CWIP Rate Impact Analysis

III. STATEMENT H, STATEMENT H CERT AND STATEMENT H ECIC

7. Q. PLEASE EXPLAIN WHY THE COMPANY IS FILING STATEMENT H, STATEMENT H CERT AND STATEMENT H ECIC.

A. The Company is filing these statements to show the impact of the Certification and ECIC adjustments. In prior GRCs, these pages were filed as one statement but, in this case, they are now renamed and reordered into:

- A summary statement, and
- The supporting Certification and ECIC statements.

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8. Q. PLEASE DESCRIBE STATEMENT H – SUMMARY OF RESULTS OF OPERATIONS.

A. Statement H provides a summary of cost of service and resulting revenue requirement based on the Company's proposed rate of return for the Certification and ECIC periods. Moving from left to right, pages one and two summarize by column:

b) Adjusted and allocated results of operations for the Test Period ended September 30, 2024;

c) Certification adjustments;

d) ECIC adjustments;

e) The total Certification and ECIC adjustments;

f) The impact of Certification and ECIC adjustments on the earned rate of return;

g) Additional revenue requirement after Certification adjustments;

h) Additional revenue requirement after ECIC adjustments;

i) Lenzie incentive and Fleet allowed return adjustment;

j) Annualized fuel and purchased power revenue;

k) Revenue requirement for rate design; and

l) Additional revenue requirement.

Page two shows the Federal Income Tax ("FIT") calculations associated with the components listed above.

9. Q. WHAT DOES THE INCENTIVE REVENUE REQUIREMENT IN COLUMN I ON PAGE 1 OF STATEMENT H REPRESENT?

A. There are two elements combined in this column. As provided for in NAC § 704.9484 and in compliance with the Commission's Order in Docket No.

04-6030 (the Second Amendment to Nevada Power's 2003 Integrated Resource Plan ("IRP")), the Company applies a 3 percent enhanced return on equity to its Lenzie generating facility (not including the purchase cost). Additionally, in compliance with the Commission's Order in Docket No. 23-06007 (Nevada Power's 2023 GRC), the Company is reducing the overall return allowed for the fleet vehicles that were purchased based on the analysis that utilized a three percent marginal cost of capital.

Column (i) on page one of Statement H represents the additional revenue requirement necessary to earn the 3 percent enhanced return on the net investment for the Lenzie facility less the revenue requirement reduction for the fleet vehicles. Net investment is measured as gross plant less the accumulated provision for depreciation and accumulated deferred income taxes for liberalized depreciation. Overall, the change in revenue requirement necessary to earn the requested rate of return without incentives is 7.95 percent, as demonstrated in the revenue requirement calculation on page 1 at columns (g) and (h). With the addition of the two adjustments combined, the rate of return with incentives remains 7.95 percent, as shown in column (k).

10. Q. HOW WAS THE REVENUE REQUIREMENT REQUESTED IN THIS PROCEEDING CALCULATED?

A. Additional revenue requirement is the product of the proposed rate base times the difference between the earned and requested rates of return, times a "net to gross" multiplier. The "net to gross" multiplier is a measure of the impacts of revenue driven expenses, such as FIT, mill tax and uncollectible accounts expense. The need to synchronize interest expense and Cash Working Capital makes this calculation more complex. A change in revenue requirement generates a change in FIT, mill tax and uncollectible expense, which in turn causes a change in Cash Working Capital, a component of rate base.

An adjustment to rate base changes the revenue requirement directly by changing the amount of income necessary to earn a specified rate of return, and indirectly by changing synchronized interest expense, and therefore, FIT. As a result, the Statement H model uses a series of synchronous formulas to simultaneously calculate changes in all of the above components. Using the resultant change in revenue requirement as a basis, expense and Cash Working Capital changes are recalculated to verify the accuracy of the formulas. Using this Statement H presentation, the additional revenue requirement reflects the need for additional mill tax recovery, along with uncollectible accounts expense and FIT.

This is the same calculation that has been utilized at Nevada Power in all GRCs since Sierra Pacific Resources (now NV Energy, Inc.) acquired Nevada Power in 1999.

11. Q. PLEASE DESCRIBE STATEMENT H CERT – SUMMARY OF RESULTS OF OPERATIONS FOR THE CERTIFICATION PERIOD.

A. Statement H-CERT provides a summary of cost of service and resulting revenue requirement based on the Company’s proposed rate of return for the Certification Period. Moving from left to right, page one summarizes by column:

b) Adjusted and allocated results of operations for the Test Period ended September 30, 2024;

c) Certification adjustments;

d) The impact of Certification adjustments on the earned rate of return;

e) Additional revenue requirement after certification adjustments;

f) Revenue requirement before incentives;

g) Lenzie incentive;

h) Fleet allowed return adjustment;

i) Revenue requirement with incentives;

j) Annualized fuel and purchased power revenue;

k) Revenue requirement for rate design; and

l) Additional revenue requirement through the Certification Period.

Page two shows the FIT calculations associated with the components listed above and an effective tax rate calculation.

Page three of Statement H-CERT shows the total Company summary results of operations including regulatory adjustments on September 30, 2024, with a breakdown between Nevada Power's retail and FERC jurisdictions.

12. Q. PLEASE DESCRIBE STATEMENT H-ECIC – SUMMARY OF RESULTS OF OPERATIONS FOR THE ECIC PERIOD.

A. Statement H-ECIC is similar to Statement H-CERT but it provides a summary of cost of service and resulting revenue requirement based on the Company's proposed rate of return for the ECIC period ending September 12, 2025. Moving from left to right, page one summarizes by column:

b) Certification revenue requirement before incentives for the Certification Period ended February 28, 2025;

c) ECIC adjustments;

d) ECIC results of operations;

e) Additional revenue requirement before incentives;

f) ECIC revenue requirement before incentives;

g) Lenzie incentive;

h) Fleet allowed return adjustment;

i) ECIC revenue requirement with incentives;

j) Annualized fuel and purchased power revenue;

k) Revenue requirement for rate design; and

l) Additional revenue requirement.

Page two shows the FIT calculations associated with the components listed above and an effective tax rate calculation.

This schedule flows directly into Schedule H-2, Unbundled Revenue Requirement.

13. Q. WHAT DOES THE INCENTIVE REVENUE REQUIREMENT IN COLUMN G AND H ON PAGE 1 OF STATEMENT H-CERT AND STATEMENT H-ECIC REPRESENT?

A. Column (g) represents the enhanced return on equity for the Lenzie generating facility that was previously described. Column (h) represents the allowed return adjustment for the fleet vehicles, also previously discussed.

IV. SCHEDULE H-1 CERT

14. Q. PLEASE DESCRIBE SCHEDULE H-1 CERT.

A. Schedule H-1 is a four-page exhibit that summarizes the Certification adjustments in the H-CERT schedules. The adjustments are grouped by major category (i.e., sales revenue, other operating revenue, other operation and maintenance (“O&M”) expense, etc.), subtotaled, and carried forward to Statement H. The appropriate

"CERT" schedule for each adjustment is referenced in Column (a), and the FIT impacts, if any, are shown in Columns (d) through (f).

V. CERTIFICATION SCHEDULES H-CERT-02 THROUGH H-CERT-07

15. Q. PLEASE DESCRIBE SCHEDULE H-CERT-02.

A. Schedule H-CERT-02 shows the revenue reconciliation, which details the component adjustments necessary to convert total recorded and adjusted revenue to annualized present rate revenue applicable to general rate recovery. The present rate revenues included in this reconciliation are shown in Statement J. This schedule also summarizes revenue credits and provides a placeholder for updating these credits at Certification.

16. Q. PLEASE DESCRIBE SCHEDULE H-CERT-03.

A. Schedule H-CERT-03 removes recorded fuel and purchased power costs from operating expense. In order to arrive at a revenue requirement for rate design purposes, fuel and purchased power costs are later added back at a level equivalent to present Base Tariff Energy Rate ("BTER") revenue. Schedule H-CERT-03 also develops the adjusted fuel and purchased power expense for Cash Working Capital by applying the recorded BTER component percentages to the present rate revenue.

17. Q. PLEASE DESCRIBE SCHEDULE H-CERT-04, CASH WORKING CAPITAL CALCULATION.

A. Schedule H-CERT-04 shows the calculation of the Cash Working Capital Allowance after Certification adjustments and after inclusion of the additional revenue requirement necessary to allow the Company to earn its proposed rate of return. The Cash Working Capital Allowance is calculated using a similar methodology previously approved in prior dockets. For this proceeding, the Company revised the lag-day calculations for long-term debt, most recently utilized by the Company in Docket No. 08-12002 (2008 Nevada Power GRC), which more appropriately reflects the frequency and increased amount of the Company's interest expense obligations. This is addressed further in the testimony of Harold Walker, III. Additionally, as discussed by Company witness Matthew Valentic, the change in lag days has been incorporated into H-CERT-04, rather than Statement N as has been done in prior cases. This does not impact the calculation, but rather isolates and more clearly demonstrates a change to the proposed revenue requirement being made by the Company from the recorded and adjusted results of operations for the Test Period as presented in Statement N.

18. Q. PLEASE EXPLAIN SCHEDULE H-CERT-05, CERTIFICATION ADJUSTMENT – MILL TAX.

A. Schedule H-CERT-05 adjusts the recorded mill tax expense to a level reflecting the assessment rate and present rate revenues on September 30, 2024, as shown on Statement J. While the mill tax is collected only in general rates, mill tax expense is based on total revenue,[1] and as such, revenues for the following must also be reflected in the mill tax calculation: present rate BTER, DEAA, R-BTER, REPR, TRED, EEPR Base and Amortization, EEIR Base and Deferral, NDPP, ESPC and ESDR.

[1] Revenue collected pursuant to the Base Tariff General Rate ("BTGR"), BTER, Renewable-BTER ("R-BTER"), DEAA, and the special purpose Renewable Energy Program Rate ("REPR"), Temporary Renewable Energy Development Rate ("TRED"), Energy Efficiency Program Rate ("EEPR"), and Energy Efficiency Implementation Rate ("EEIR"), Natural Disaster Protection Plan ("NDPP"), Expanded Solar Program Cost ("ESPC") and Expanded Solar Discount Recovery ("ESDR").

For purposes of calculating mill tax, the TRED revenue is the amount paid out of the TRED Trust, not the amount collected through the TRED rate. Similarly, the EEIR revenue is the sum of the base and deferral, which are recognized as revenue. The amortization of the EEIR deferral balance is not considered revenue for purposes of mill tax assessment. Finally, Schedule H-CERT-05 reflects the mill tax expense associated with the additional Certification revenue requirement and the incentive revenue requirement and will be updated at Certification.

19. Q. PLEASE EXPLAIN SCHEDULE H-CERT-06, CERTIFICATION ADJUSTMENT – INTEREST SYNCHRONIZATION.

A. Schedule H-CERT-06 recognizes the impact of changes in rate base and capital structure on the level of interest charges included in the calculation of FIT for the Test Period and the Certification Period. This schedule also reflects the impact of the additional Certification revenue requirement and incentive revenue requirement, which impact Cash Working Capital. Cash Working Capital impacts rate base and rate base impacts interest expense.

Consistent with the Commission's treatment in prior dockets, the sum of the weighted debt components of the proposed rate of return (long- and short-term debt, customer deposits, and where applicable, preferred stock) have been applied to the appropriate rate base to arrive at the interest levels used for the calculation of federal income tax liability in Statement H, page two. Schedule H-CERT-06 will be updated at Certification.

20. Q. PLEASE DESCRIBE SCHEDULE H-CERT-07, CERTIFICATION ADJUSTMENT – UNCOLLECTIBLE ACCOUNTS EXPENSE.

A. Schedule H-CERT-07 adjusts the recorded Uncollectible Accounts Expense for changes in operating revenues as a result of the present rate calculations from Statement J, the additional Certification revenue requirement, and the incentive revenue requirement. Uncollectible Accounts Expense is calculated by applying an Uncollectible Accounts ratio to anticipated operating revenue. The operating revenue is calculated in the same manner as the revenue for the mill tax assessment. H-CERT-07 will also be updated at Certification to include NDPP and ESAP revenue.

The Uncollectible Accounts ratio represents a three-year average of uncollectible expense (FERC Account No. 904) as compared to the associated revenue for the same three-year period. This calculation is consistent with the methodology approved by the Commission in Docket No. 06-11022 and used most recently in Nevada Power's 2023 GRC, Docket No. 23-06007.

VI. SCHEDULE H-1 ECIC

21. Q. PLEASE DESCRIBE SCHEDULE H-1 ECIC.

A. Schedule H-1 is a four-page exhibit that summarizes the ECIC adjustments in the H-ECIC schedules. The adjustments are grouped by major category (i.e., sales revenue, other operating revenue, other O&M expense, etc.), subtotaled, and carried forward to Statement H. The appropriate "ECIC" schedule for each adjustment is referenced in Column (a), and the FIT impacts, if any, are shown in Columns (d) through (f).

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<u>VII. ECIC SCHEDULES H-ECIC-04 THROUGH H-ECIC-07</u>

22. Q. PLEASE DESCRIBE ECIC SCHEDULE H-ECIC-04, CASH WORKING CAPITAL CALCULATION.

A. Schedule H-ECIC-04 shows the calculation of Cash Working Capital Allowance after ECIC adjustments and after inclusion of the additional revenue requirement necessary to allow the Company to earn its proposed rate of return. This schedule starts with the Certification results of operations, adds the ECIC adjustments and calculates the final Cash Working Capital Allowance.

23. Q. PLEASE DESCRIBE ECIC SCHEDULE H-ECIC-05, MILL TAX AND ECIC SCHEDULE H-ECIC-07, UNCOLLECTIBLE ACCOUNTS EXPENSE.

A. Schedule H-ECIC-05 and Schedule H-ECIC-07 mirror the revenue driven adjustments contained in Schedule H-CERT-05 and Schedule H-CERT-07 by adjusting the Certification mill tax expense and uncollectible expense to reflect the ECIC present rate revenues. The ECIC expense levels are then adjusted to reflect the additional revenue requirement including incentives.

24. Q. PLEASE EXPLAIN ECIC SCHEDULE H ECIC-06, ADJUSTMENT – INTEREST SYNCHRONIZATION.

A. Schedule H-ECIC-06 recognizes the impact of changes in rate base and capital structure on the level of interest charges included in the calculation of FIT for the ECIC period. This schedule also reflects the impact of the additional Certification revenue requirement and incentive revenue requirement, which impact Cash Working Capital.

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VIII. SCHEDULE H-CERT-01 ECIC

25. Q. PLEASE DESCRIBE SCHEDULE H-CERT-01 ECIC.

A. Schedule H-CERT-01 ECIC is a 29-page summary of adjustments for both the Certification Period and the ECIC period.

IX. ECIC SCHEDULE H-2 UNBUNDLED REVENUE REQUIREMENT

26. Q. PLEASE DESCRIBE SCHEDULE H-2 – UNBUNDLED REVENUE REQUIREMENT.

A. Schedule H-2 allocates the total Nevada jurisdictional revenue requirement from Statement H, page 1, column (k), to the three basic utility functions – generation, transmission, and distribution. The unbundled revenue requirement serves as the basis for rate design.

Schedule H-2 starts with the recorded results of operations for the 12 months ended September 30, 2024, as allocated in Statement N and summarized on Statement H, page 1, column (b).

Based on the detail provided in Schedules H-CERT-01 and H-ECIC-01, the Certification and ECIC adjustments are added to the recorded numbers. Finally, the additional revenue requirement and the associated adjustments to mill tax, uncollectable accounts expense, interest expense, federal income tax liability, and Cash Working Capital are added. The resulting values shown in column (g) are allocated or unbundled into the three basic functions – generation, transmission, and distribution.

27. Q. HOW WAS THE UNBUNDLED COST OF SERVICE CALCULATED BY FUNCTION?

A. Most capital and a significant portion of the operation and maintenance expenses are directly assigned to a specific function (generation, transmission, or distribution), based on FERC system of accounts classification. Other components, such as general and intangible plant and administrative and general expense, are allocated using one of the 10 allocators shown on page 19 of Schedule H-2. Similar to Statement N, the allocators for each component are indicated next to the component.

X. STATEMENT I

28. Q. WHAT IS THE PURPOSE OF STATEMENT I?

A. Statement I is required by NAC § 703.2351 if the utility's Statement H contains estimated changes beyond the year of testing. Consistent with the Commission's regulations, the Certification filing will be made within 120 days of the end of the Certification Period, February 28, 2025.

XI. H-CERT SCHEDULES RELATED TO PAYROLL

29. Q. PLEASE DESCRIBE SCHEDULE H-CERT-17.

A. In this and prior GRC proceedings, Schedule H-CERT-17 shows the calculation of annualized payroll, benefits and pension expense. The annualizations that are calculated through Schedule H-CERT-17 are intended to ensure that revenue requirement reflects the ongoing costs of payroll, benefits and pension expense.

Pages 1 through 4 of the Annualized Payroll reflect Nevada Power's recorded O&M labor costs for the Test Period, as well as the estimated change in annualized payroll costs attributable to Nevada Power's O&M activities at the end of the Certification Period. Annualized payroll costs reflect staffing and salary changes, overtime estimates and other changes in compensation for regular and temporary employees effective as of February 28, 2025.

Pages 1 and 5 of the Annualized Payroll reflect Nevada Power's recorded O&M benefit and pension expenses for the Test Period, as well as the estimated change in annualized benefit and pension expenses attributable to Nevada Power's O&M activities as of the 12 months ended September 30, 2024. Annualized benefit and pension expenses reflect anticipated increases in 401(k) contributions, health insurance cost changes, and known and measurable 2024 pension costs effective as of February 28, 2025.

30. Q. PLEASE PROVIDE AN OVERVIEW OF THE RESULTS AND DEVELOPMENT OF THE PAYROLL ANNUALIZATION.

A. The payroll annualization results in an increase in payroll expense of $19.512 million estimated as of the end of the Certification Period for the aggregate of Nevada Power, Sierra, and their parent company, NV Energy, Inc., as compared to Test Period results (H-CERT-17, page 3, lines 19 through 28). The overall increase between Test Period and Certification Period was largely generated at Nevada Power and Sierra, with a combined increase of $20.8667 million, and a $1.355 million decrease at the parent company. The $19.512 million overall increase was allocated to Nevada Power, Sierra, and the parent company using each entity's Test Period payroll distribution percentages (*i.e.*, by company and by accounts). The jurisdictional allocated increase, including an estimated payroll tax adjustment, at Nevada Power is $5.843 million (H-CERT-17, page 1, line 22).

31. Q. PLEASE EXPLAIN HOW COMMON FUNCTIONS OR INTERCOMPANY PAYROLL CHARGES IMPACT NEVADA POWER IN THIS SCHEDULE.

A. The payroll annualization schedule takes into account the following practices:

- Due to the utility holding company structure, Nevada Power employees provide services that are either directly charged or allocated to Nevada Power; its sister operating utility, Sierra; and/or its parent company, NV Energy, Inc.; and
- Nevada Power also may receive direct or allocated charges from employees of its sister operating utility and/or parent company as a result of services their employees performed on behalf of Nevada Power.

32. Q. PLEASE EXPLAIN THE CALCULATION OF NV ENERGY, INC., NEVADA POWER AND SIERRA'S ANNUALIZED PAYROLL EXPENSE ADJUSTMENTS.

A. The calculation of each individual company's annualized payroll expense was performed by determining the annualized payroll amount and subtracting the recorded payroll.

Annualized Payroll: The annualized payroll calculation is composed of three parts:

1. The base pay salaries of regular employees were identified by each company as of October 1, 2024. Staffing levels are assumed to remain at that level for purposes of the estimate as of February 28, 2025.
2. Overtime percentages for regular employees were calculated for non-represented and represented employees based on Test Period data. The analysis assumes that the same historic rates of overtime will continue for NV Energy, Inc., Nevada Power, and Sierra's two employee classes going

forward. These overtime percentages are applied to regular employees' base pay salaries by company and employee class to estimate the respective overtime payroll.

3. Estimates of "Other" compensation, not included in base salaries, used the Test Period data of each company. Again, the underlying assumption is that historical occurrences or level of "Other" compensation will continue by NV Energy, Inc., Nevada Power, and Sierra's employees in the future. "Other" compensation includes the adjusted Short-Term Incentive Plan ("STIP") payout in 2023, as that was the payout during the Test Period, as discussed above. Nevada Power expects to update the calculation at Certification to include the 2024 payout instead. Long-Term Incentive Pay is included in the payroll annualization and removed in total through Statement N, and in a separate pro forma, H-CERT-16. Please refer to the prepared direct testimony of Jennifer Oswald for more information regarding the overall compensation and benefits' programs provided to employees.

These components – base pay, overtime and revised historic "Other" compensation – are combined to arrive at the total annualized payroll by company.

<u>Recorded Payroll:</u> The recorded payroll calculation is composed of two parts:

1. The general ledger costs, identified as payroll through a unique resource type ("RT") coding, were compiled by each individual company.

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2. Certain payroll costs that were recorded without a unique RT coding were identified by each individual company as well.

The sum of the parts as described above makes up the recorded and adjusted payroll for the Test Period.

<u>*Calculation:*</u> The calculation of each individual company's annualized payroll expense adjustment is performed by reducing each company's annualized payroll by its recorded and adjusted payroll. The "Grand Total" Payroll increase in the aggregate amount of $19.512 million and the individual company's annualized payroll adjustments are shown in H-CERT-17, page 3, line 38.

33. Q. WERE ANY ADJUSTMENTS MADE TO EXECUTIVE COMPENSATION?

A. Yes. The Vice President, Transmission Development & Energy Market Policy, departed on January 8, 2024. The related 2023 STIP compensation for this retirement was removed.

34. Q. PLEASE EXPLAIN THE ALLOCATION OF EACH INDIVIDUAL COMPANY'S PAYROLL EXPENSE TO NEVADA POWER'S O&M.

A. Each company's Payroll Expense was allocated based on the historical payroll charging patterns of each company by functional grouping. In other words, NV Energy, Inc., Nevada Power and Sierra provide services to one another, and directly charge and/or allocate the associated payroll costs to each other as appropriate. Therefore, just as payroll is not restricted to the originating or "home" company, the Payroll Expense adjustments are not restricted to the home company, and thus

Payroll Expense adjustments are allocated to each of the companies based on the historical charging patterns of each company.

35. Q. WHAT IS THE TOTAL ADJUSTMENT TO NEVADA POWER'S COST OF SERVICE THAT RESULTED FROM THE PAYROLL EXPENSE CERTIFICATION ADJUSTMENTS?

A. The total cost of service increase is $5.454 million, as shown on H-CERT-17, page 1, line 18, column e. The aggregate of NV Energy, Inc., Nevada Power, and Sierra's Payroll Expense adjustment allocated to Nevada Power's O&M and then jurisdictionalized for Nevada is an increase of $5.361 million as shown in H-CERT-17, page 1, line 18, column g. A payroll tax adjustment of $0.482 million, as shown on H-CERT-17, page 1, line 20, is added to the $5.361 million to arrive at a total increase of $5.843 million.[2]

36. Q. PLEASE DESCRIBE THE BENEFITS PORTION OF THE SCHEDULE.

A. Schedule H-CERT-17, on page 5 of 5, adjusts the cost of benefits expense, which are brought forward to H-CERT-17, page 1, lines 25 through 35. Page 5 of Schedule H-CERT-17 aggregates the adjustments for the estimated net change in medical/dental/vision costs ("Health Insurance Costs") and the 401(k) Company matching costs as compared to the recorded costs during the Test Period. This schedule reflects an aggregate increase of $1.675 million, with a Nevada jurisdictional cost of service increase amount of $1.649 million as shown on H-CERT-17, page 1, line 29. Please refer to Ms. Oswald's prepared direct testimony for more information concerning the Companies' overall compensation and benefit plans.

[2] Nevada Power expects to update this schedule at the end of the Certification Period.

37. Q. PLEASE DESCRIBE HOW ESTIMATED HEALTH INSURANCE COSTS WERE DETERMINED FOR H-CERT-17.

A. For purposes of the schedule, health insurance costs were estimated by multiplying the October 2024 accrual amount by five, or the number of months included in the Certification Period, and adding the result to the amount booked for the last seven months of the Test Period. Estimated health insurance costs were then adjusted by the Test Period recorded health insurance costs to determine an increase of $3.831 million, as shown on H-CERT-17, page 5, line 3. This amount was then combined with the 401(k) Company match and allocated to expense as shown on H-CERT-17, page 5, line 9. The combined increase of $1.675 million was brought forward to page 1 where it was then allocated to the Nevada jurisdiction, demonstrating an overall increase of $1.649 million.

38. Q. PLEASE EXPLAIN THE 401(k) COMPANY MATCH ADJUSTMENT.

A. The adjustment for 401(k) Company match is based on the annualized cost of Company matching contributions as compared to the recorded costs during the Test Period. The total decreased amount of $0.598 million is shown on H-CERT-17, page 5, line 5. This amount was then combined with the health insurance increase, allocated to expense as shown on H-CERT-17, page 5, line 9. The combined increase of $1.675 million was brought forward to page 1 where it was then allocated to the Nevada jurisdiction, demonstrating an overall increase of $1.649 million.[3]

[3] The Company expects to update this portion of the adjustment at the end of the Certification Period.

39. Q. PLEASE DESCRIBE THE PENSION PORTION OF THE SCHEDULE.

A. Schedule H-CERT-17 includes the cost of retirement benefits for both active and retired employees. Specifically, the schedule adjusts recorded Test Period costs for Pension Service Costs and Pension Non-Service Costs, as accounted for under Accounting Standards Codification ("ASC") 715-20 and ASC 715-30. Within each pension cost classification, there are pension costs, supplemental executive retirement program ("SERP"), and Other Post-Employment Benefits ("OPEB") as accounted for in ASC 715-60. The schedule shows an aggregate decrease to the Nevada jurisdictional cost of service in the amount of $1.112 million as shown on H-CERT-17, page 1, line 35.

40. Q. PLEASE EXPLAIN THE PENSION COST ADJUSTMENT.

A. The pension cost adjustment represents the difference between the annualized costs of the Company's retirement plan as compared to the recorded costs during the Test Period—in this case, a decrease in cost. The annualized cost, as provided by the consulting actuary, Willis Towers Watson, is Nevada Power's allocated share of NV Energy, Inc.'s Retirement Plan based on the actuarial estimates for 2023 and 2024.

The Pension Service Cost increase is $0.008 million, shown on H-CERT-17, page 5, line 14. This amount was then combined with Pension Service Costs for the restoration and the post-retirement adjustments and allocated to O&M. The result is an increase of $0.004 million as shown on H-CERT-17, page 5, line 22.

The Pension Non-Service Cost decreased $0.913 million, shown on H-CERT-17, page 5, line 26. This amount was then combined with Pension Non-Service Costs for the restoration and the post-retirement adjustments. The entire Pension Non-Service Cost expense is classified as an O&M expense, in compliance with ASC 715-20. The overall result is a decrease of $1.133 million as shown on H-CERT-17, page 5, line 32.

The total adjustments to Pension Service Costs and total Non-Service Pension Costs are summed to calculate a total pension cost decrease of $1.129 million as shown on H-CERT-17, page 5, line 34. This amount is brought forward to page 1, line 35, where it was then allocated to the Nevada jurisdiction for a net decrease of $1.112 million.

In his prepared direct testimony, Daniel Morley explains how pension costs are determined by the Company's actuary, Willis Towers Watson.

41. Q. PLEASE EXPLAIN THE RESTORATION ADJUSTMENT.

A. Consistent with prior dockets, the restoration component of SERP has been included in the calculation of annualized pension costs; however, there were no recorded restoration costs during the Test Period and none expected in the annualized calculation, reflecting no change to pension service costs as shown on H-CERT-17, page 5, line 17. There was a decrease in pension non-service costs of $0.108 million as shown on H-CERT-17, page 5, line 28. These amounts were then combined with the pension and post-retirement adjustments. The pension service costs were allocated to O&M; however, non-service costs were all classified as O&M expense in compliance with ASC 715-20. Nevada Power is not requesting recovery of non-restoration SERP costs in compliance with past Commission orders.

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42. Q. PLEASE EXPLAIN THE OPEB ADJUSTMENT INCLUDED IN THIS SCHEDULE.

A. The OPEB adjustment represents an increase in OPEB costs as a result of the difference between the annualized OPEB costs as compared to the recorded costs during the Test Period. The annualized cost, as provided by the consulting actuaries, Willis Towers Watson, is Sierra's portion of the NV Energy, Inc. Post-Retirement Welfare Plan based on the actuarial estimates for 2023 and 2024.

The annualized OPEB costs are $0.001 million less than recorded, reflecting a small decrease to pension service costs as shown on H-CERT-17, page 5, line 18. The pension non-service costs also decreased by $0.112 million as shown on H-CERT-17, page 5, line 30. These amounts were then combined with restoration and pension adjustments. The pension service costs were allocated to O&M.

In his prepared direct testimony, Mr. Morley explains how pension costs are determined by the Company's actuary, Willis Towers Watson.

43. Q. PLEASE DESCRIBE SCHEDULE H-CERT-34.

A. Schedule H-CERT-17 shows the calculation of annualized payroll, which excludes the payroll related to the NDPP during the Test Period. Therefore, for transparency, H-CERT-34 was created for the corresponding payroll related to NDPP. All incremental labor related to NDPP was properly recorded within the NDPP regulatory asset, and thus no adjustment is needed to exclude any O&M costs incurred in the Test Period. The total recorded payroll in H-CERT-17 and H-CERT-34 combined, equals the total recorded payroll for the Companies during the Test Period

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XII. H-CERT SCHEDULES RELATED TO EXISTING REGULATORY ASSETS AND LIABILITIES, NEW REGULATORY ASSETS AND LIABILITIS, AND CERTIFICATION ADJUSTMENTS

44. Q. PLEASE DESCRIBE SCHEDULE H-CERT-19, DOCKET NO. 23-06007 INCREMENTAL GENERAL RATE CASE COSTS REGULATORY ASSET.

A. This schedule represents the Company's request for the inclusion of the regulatory asset related to the 2023 Nevada Power GRC. While this regulatory asset is considered "new," the Commission has previously authorized the Company to defer incremental costs associated with preparing and presenting to the Commission general rate review and IRP applications. Incremental costs pertain to costs associated with consultants and travel and do not include any labor expense associated with internal employees. No carrying charges are being applied to the balance, pursuant to the Commission's order in Docket No. 22-06014.

The Company incurred and deferred $1.036 million and requests a three-year amortization.

45. Q. PLEASE DESCRIBE SCHEDULE H-CERT-20, DOCKET NO. 21-06001 INCREMENTAL 2021 TRIENNIAL RESOURCE PLAN AND AMENDMENTS COSTS REGULATORY ASSET.

A. This schedule represents the Company's request for the inclusion of the incremental costs in the regulatory asset related to the 2021 IRP Amendments that have been filed since the last Nevada Power GRC in 2023. The Commission has previously authorized the Company to defer incremental costs associated with preparing and presenting to the Commission general rate review and IRP applications. Incremental costs pertain to costs associated with consultants and travel and do not include any labor expense associated with internal employees. No carrying charges are being applied to the balance, pursuant to the Commission's Order in Docket No. 22-06014.

The Company incurred and deferred $0.392 million since the 2023 Nevada Power GRC and requests a three-year amortization.

46. Q. PLEASE DESCRIBE SCHEDULE H-CERT-21, MISCELLANEOUS DEFERRED ADDITIONS AND DEDUCTIONS TO RATE BASE.

A. This schedule estimates the balances of the miscellaneous additions and deductions to rate base as of February 28, 2025, and as of September 30, 2025, where applicable.[4] The balances on September 30, 2024, are updated with estimated activity to arrive at the February 28, 2025, or September 30, 2025, balances, and result in a $14.599 million decrease in rate base additions and a $7.649 million decrease in rate base deductions. The overall result of the schedule is a $6.950 million decrease to rate base. Additionally, this schedule adjusts the amortization expense for regulatory items whose amortizations expired during the Test Period, reducing the expense by $23.709 million. The Company plans to update this schedule in its Certification filing with actual balances as February 28, 2025.

47. Q. PLEASE DESCRIBE SCHEDULE H-CERT-24, ADJUSTMENTS TO TEST PERIOD EXPENSES.

A. Various FERC accounts were analyzed during the preparation of Schedules K-2, K-3, K-4, K-5, K-6 and K-7, sponsored by Company witness Mr. Morley, for this filing. Invoices from vendors providing services for amounts recorded in these

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[4] Docket No. 22-06014, *Order*, at 183-184, ¶¶ 546-549 (Dec. 28, 2022).

schedules were reviewed in detail to determine whether they were valid expenses for the Test Period and properly included in the filing. Expenses for certain non-recurring and other activities identified during this analysis were eliminated from cost of service unless they were appropriately treated as a regulatory asset. Transactions in other accounts were also reviewed to determine if any adjustments needed to be made to Test Period recorded expense. Schedule H-CERT-24 adjusts cost of service for these items. The Company has determined that the remaining Test Period expenses recorded in these schedules that were not adjusted through Schedule H-CERT-24, other schedules and through Certification, are reasonable and should be included in determining the annual revenue requirement.

Overall, $1.069 million of jurisdictionalized O&M expenses were removed from revenue requirement for the following various items:

- Correction of recorded intercompany charges in the amount of $0.980 million;
- Relocation expenses recorded to the incorrect Company of $0.095 million, and
- Adjustments in the net amount of $0.006 million to recoverable expenses for the portion of membership dues attributed to lobbying expenses for Edison Electric Institute and the allocation of dues expense between the Companies for the North American Transmission Forum.

$2,795 of advertising expenses were erroneously recorded to FERC Account 930100 during the Test Period. H-CERT-24 moves those expenses to the more appropriate FERC Account 909000, in accordance with the Bureau of Consumer

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Protection's position in Docket No. 23-06007.[5] The Company believes these costs will continue to be incurred and thus have been included in revenue requirement.

48. Q. PLEASE DESCRIBE SCHEDULE H-CERT-25, DOCKET NO. 24-05041 INCREMENTAL 2024 TRIENNIAL RESOURCE PLAN AMENDMENTS COSTS REGULATORY ASSET.

A. This schedule represents the Company's request for the inclusion of the incremental costs in the regulatory asset related to the 2024 Joint IRP. The Commission has previously authorized the Company to defer incremental costs associated with preparing and presenting general rate review and IRP applications to the Commission. Incremental costs pertain to costs associated with consultants and travel and do not include any labor expense associated with internal employees. No carrying charges are being applied to the balance, pursuant to the Commission's Order in Docket No. 22-06014.

The Company estimates it would have incurred and deferred an estimated $1.412 through the Certification Period and requests a three-year amortization.

49. Q. PLEASE DISCUSS SCHEDULE H-CERT-32, FLEX PAY PROGRAM REGULATORY ASSET.

A. Schedule H-CERT-32 represents the Company's request to include the regulatory asset, discussed and approved in Docket Nos. 14-10019 and 15-11003, containing the implementation costs to establish the Flex Pay Program, in rate base and amortize the balance over 11 years. This amortization period was selected as this is

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[5] Docket No. 23-06007, *Modified Final Order*, at 93, ¶ 289 (February 16, 2024).

the normal book life of the property. This is the Company's first opportunity to request recovery since the completion of the initial pilot program. The Company's justification for recovery and the outcome of the required cost benefit analysis is discussed in more detail in the prepared direct testimony of Company witness Antoine Tilmon. Nevada Power is requesting recovery of $5.634 million in implementation costs and an estimated $2.442 million in carry costs as of the Certification Period.

50. Q. PLEASE DESCRIBE SCHEDULE H-CERT-33, RESET OF PREVIOUSLY APPROVED AMORTIZATIONS.

A. This schedule resets any previous Commission-approved amortizations that would have expired during the rate-effective period, or more specifically December 31, 2026. To avoid overcollection in the event Nevada Power does not file another GRC and put new rates into effect before this date, the amortizations have been extended for another three-year period as of the proposed rate-effective period for this filing, October 1, 2025 – September 30, 2028. A three-year period was selected due to the Companies having to historically file a GRC **at least** (emphasis added) every three years, which would be the maximum amount of time between filings.[6]

51. Q. PLEASE DESCRIBE SCHEDULE H-CERT-35, NDPP REGULATORY ASSET.

A. Schedule H-CERT-35 represents $0.358 million that the Company was ordered to remove from the NDPP Regulatory Asset in Docket No. 24-03006. The Commission determined these costs, which were comprised of legal fees related to

[6] *See* Assembly Bill 524 (2023), codified in NRS 704.110(3).

the NDPP filings and consulting work provided by Applied Analysis, were more appropriate to be recovered through a GRC proceeding, and thus they have been submitted for recovery in this proceeding. The Company is proposing a three-year amortization of $0.119 million per year.

52. Q. PLEASE DESCRIBE SCHEDULE H-CERT-36, BUSINESS TRANSFORMATION STRANDED NBV COSTS DEFERRED DEBIT.

A. This schedule reflects the balance of the miscellaneous deferred debit established to record the stranded NBV of software replaced through Nevada Power's long-term IT transformation strategy initiative as discussed initially by Nevada Power witness Leila Hempen in the Sierra's 2022 GRC.[7] Initially, the Company had placed these stranded NBV balances into a regulatory asset. However, in response to the Commission's Order in Docket No. 24-02026,[8] the costs were transferred into a FERC 186 Account, without carrying charges. At this time, the Company is requesting regulatory asset treatment of the existing balance. The estimated balance at Certification to be included in rate base is $0.214 million and is proposed to be amortized over a three-year period, resulting in an annual amortization amount of $0.071 million.

53. Q. PLEASE DESCRIBE SCHEDULE H-CERT-37, NEM AB 405 DEFERRED DEBIT.

A. This schedule reflects the balance of the miscellaneous deferred debit (recorded to a FERC 186 Account) established to capture the difference between the general rate

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[7] Docket No. 22-06014, Direct Testimony of Leila Hempen, at 4, Q&A 8.

[8] *See* Docket No. 24-02026, *Modified Final Order*, at 116-117, ¶¶ 368-370 (November 12, 2024).

revenues (basic service charge plus BTGR) and the cost-based rates used to establish the NMR-A rate rider, initially approved in Docket Nos. 16-06006, 17-07026, and 19-06002. The Company recognizes the contention surrounding this topic. Nonetheless, an alternate solution has not been established thus far,[9] and thus, the Company is requesting amortization of the balance calculated using the previously approved methodology. This proposal bridges the gap until an alternative solution is approved and embedded in rates. This methodology is consistent with prior requests that have been approved by the Commission and, therefore, familiar to interested parties. The estimated balance at Certification is $27.472 million and is proposed to be amortized over a three-year period, resulting in an annual amortization amount of $9.157 million. The Company is not requesting rate base treatment.

54. Q. PLEASE DESCRIBE SCHEDULE H-CERT-38, PEARSON BUILDING UTILIZATION.

A. The Pearson Building ("Pearson") is Nevada Power's general office building and the corporate home of NV Energy, Inc. In ordering paragraph 156 in Docket No. 08-12002, the Commission stated that "[u]nless the utilization of the Pearson building falls significantly below the current level, the Commission does not expect a need to address this issue in a future general rate case." The employee count at Pearson as of September 30, 2024, had increased to 930 from 835 as of May 31, 2023. Full occupancy was defined as 920 per Docket No. 93-11045, and thus the Company is proposing to remove the adjustments related to Pearson utilization in this case. However, there was an adjustment recorded in Statement N resulting from

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[9] See prepared Direct testimony of Company witnesses Jeff Bohrman and Samantha Prest for the Company's proposal to address this topic. The Commission's order in Docket No. 23-06007, at pg. 109, ⁋ 335, directed Nevada Power to include "a recommendation or recommendations that could address such potential revenue shortfall associated with NEM."

the prior Nevada Power GRC, and thus H-CERT-38 is reversing that adjustment to include all previously disallowed items in their respective categories: an increase to net plant, an increase to depreciation expense, an increase to Pearson lease expense and the amortization of the building and parking lot gain. Additionally, there was a Pearson lease levelized adjustment that ended as of July 2024, which has been normalized for purposes of calculating revenue requirement. The Company plans to update this schedule in its Certification filing with actuals as of February 28, 2025.

55. Q. PLEASE DESCRIBE SCHEDULE H-CERT-39, INCLUSION OF THE DEFERRED PORTION OF RG BESS.

A. This schedule represents the Company's request to include the portion of RG BESS that was deferred in Docket No. 23-06007 by reversing the adjustment that is currently in Statement N. In its Order from the above-referenced docket, the Commission deferred $55.5 million, and the related pro-rata portion of depreciation expense, accumulated depreciation, accumulated deferred income taxes, the investment tax credit, and the amortization of the investment tax credit.[10] The prudency of these costs and the justification for their inclusion in revenue requirement is supported by Company witness Jimmy Daghlian. The full balance of RG BESS is included in schedules H-CERT-12, 13, and 14 and sponsored by Company witness Christina Hanshew. Similarly, the tax impacts are reflected in schedules H-CERT-9,10,11, and 15 and are sponsored by Company witness Deborah Florence.

[10] *See* Docket No. 23-06007, *Modified Final Order*, at 74, ¶¶ 229-230 (February 16, 2024).

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56. Q. PLEASE DESCRIBE SCHEDULE H-CERT-40, DOCKET NO. 23-06008 DEPRECIATION STUDY COSTS REGULATORY ASSET.

A. This schedule represents the Company's request for the inclusion of the regulatory asset related to the 2023 Nevada Power Depreciation Study. Whie the regulatory asset is considered "new," the Commission has previously authorized the Company to defer incremental costs associated with preparing and presenting to the Commission general rate review and IRP applications. Incremental costs pertain to costs associated with consultants and travel and do not include any labor expense associated with internal employees. No carrying charges are being applied to the balance, pursuant to the Commission's Order in Docket No. 22-06014.

The Company incurred and deferred $0.173 million and requests a three-year amortization.

57. Q. PLEASE DESCRIBE SCHEDULE H-CERT-41, RTO IMPLEMENTATION COST REGULATORY ASSET.

A. This schedule represents the Company's request to include the costs, with carry, incurred and deferred into a regulatory asset thus far to develop and join an RTO, as approved in Docket No. 22-09006.[11] The costs have been split 75/25 percent between Nevada Power and Sierra, respectively, in accordance with the Order in Docket No. 22-09006. The estimated balance through the Certification Period is $0.0942 million, and the Company is requesting an annual amortization over three years of $0.260 million. Further details regarding the Company's progress regarding the RTO are provided by Company witness Michael Holland.

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[11] *See* Docket No. 22-09006, *Order*, at 153-154, ¶¶ 391-394 (March 24, 2023).

XIII. GREENLINK CWIP IN RATE BASE AND RATE IMPACT ANALYSIS

58. Q. IS THE COMPANY REQUESTING CWIP IN RATE BASE FOR THE GREENLINK PROJECT? IF SO, PLEASE DISCUSS HOW THAT HAS BEEN INCORPORATED INTO REVENUE REQUIREMENT.

A. Yes. After the Commission's Order in the Companies' 2024 Joint IRP, Docket No. 24-05041, which granted critical infrastructure designation to the remaining Greenlink projects that had not already been designated as such and determined that the GRC process was the appropriate venue to request CWIP in rate base, the Company has included CWIP in its proposed revenue requirement in this GRC. The Company's request is discussed in further detail by Mr. Behrens; the details of the projected balance will be discussed by Company witness Shahzad Lateef, but I will discuss its inclusion in revenue requirement.

Schedule H-CERT-42 reflects the recorded CWIP balance as of September 30, 2024, and the estimated CWIP balance as of February 28, 2025. Column (e) reflects the total estimated CWIP balance through the Certification Period of $347.5 million. This amount is then jurisdictionalized, ultimately leading to a $289.1 million inclusion in rate base. The "Construction Work in Progress" row in Statement H reflects that as of the end of the Test Period, the balance previously included in rate base was $0, and, thus, further represents the inclusion through a Certification adjustment.

59. Q. WHAT ADDITIONAL ITEMS DID THE COMMISSION REQUIRE TO BE INCLUDED WITH ANY REQUEST FOR CWIP IN RATE BASE.

A. In the Order from the 2024 Joint IRP, the Commission stated "[a]ny such request is required to include all financial impacts associated with the request, including a rate impact analysis that specifies the rate impact of any such proposal on each rate class."[12] To satisfy this requirement, the Company has utilized the Statement J format presented in this case and in several prior proceedings to show the impact by rate class. Rates with and without the inclusion of CWIP for Greenlink have been compared to one another, through both the Certification and ECIC periods and have been included as **Exhibit Naughton-Direct-2**. The Company is not including balances for CWIP through the ECIC period but has provided a rate impact analysis for transparency and consistency, which correlates to filed Statement J's in this case, as further discussed in the Direct testimony of Bonnie Hughey.

60. Q. WHAT IS THE AVERAGE IMPACT BY CUSTOMER?

A. As stated before, full details by rate class are found in **Exhibit Naughton-Direct-2**. Results by broader rate classifications are shown in **Table Naughton-Direct-1**.

Table Naughton-Direct-1

	per NRS			ECIC	
Customer Class	**$ Impact per month**	**% Impact per month**		**$ Impact per month**	**% Impact per month**
Residential	$ 3.57	1.2%		$ 3.69	1.2%
Non-Residential	$ 7.49	1.0%		$ 7.59	1.0%
Distribution Only Service (DOS)	$ (319.28)	-2.0%		$ (270.08)	-1.7%
All Classes	**$ 2.19**	**1.1%**		**$ 2.19**	**1.1%**

[12] Docket No. 24-05041, *Order*, at 362-63, ¶ 976 (Dec. 27, 2024).

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XIV. REGULATORY ASSET TREATMENT FOR LOW-INCOME PROGRAM

61. Q. PLEASE SUMMARIZE THE COMPANY'S LOW-INCOME RATE PROPOSAL.

A. As further discussed in the prepared direct testimony of Company witness Hank Will, Nevada Power, in compliance with the Commission's Order from Docket No. 23-06007, is proposing a low-income discount for eligible residential customers. The discount would result in a 100 percent reduction to the Basic Service Charge ("BSC") for customers with an income limit of 150 percent of the Federal Poverty Level, which is also the eligibility criteria for the State of Nevada's Energy Assistance Program ("EAP"). As an example, for a residential single-family customer, it is estimated this would provide an approximate 12.05 percent discount, or $18.50 per month.[13]

62. Q. WHAT ARE THE INHERENT REVENUE SHORTFALLS THAT ARISE FROM THE COMPANY'S PROPOSAL?

A. At the very minimum, the intent of the program is to reduce the overall costs for qualifying low-income customers, even though the overall costs for the Company to serve those customers remains the same. The proposal made by the Company naturally produces a revenue under-collection from the very first customer that enrolls, and subsequently increases as the outreach of the program does.

Additionally, the Company anticipates program implementation and administration costs ("program costs") which include the following:

- Participant processing to include income verification;

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[13] *See* Prepared Direct Testimony of Hank Will at Table Will-Direct-1

- Outreach costs to include additions to and of Company webpages;
- Updates to the Company's billing system to account for and track participating customers;
- Customer assistance expenses to include training as appropriate; and
- Compliance tracking costs.

Utilizing the ESAP program as a proxy, the Company estimates a range of $1.93 per customer per month at 30 percent participation to $1.07 per customer per month at 100 percent participation, to implement the program.[14]

63. Q. HOW DOES THE COMPANY PROPOSE TO RECOVER THE REVENUE SHORTFALL ARISING FROM CUSTOMERS PARTICIPATING IN THE PROGRAM AND THE ASSOCIATED PROGRAM COSTS?

A. The Company proposes to record both the difference between the full BSC and the discounted BSC per participating customer and any associated program costs incurred into separate regulatory assets with carry. The balance of the regulatory assets would be included in rate base, to be amortized over an appropriate period as proposed in the Company's next GRC.

64. Q. HOW DOES THE COMPANY'S PROPOSAL IMPACT CUSTOMERS?

A. As proposed, once the regulatory asset is placed into rates in the subsequent GRC, all customers, including both participating customers as well as Distribution Only Service ("DOS") customers, would be subject to recovery of this revenue shortfall. A major consideration of this proposal and the potential impact to customers is the participation levels and the overall outreach achieved. The estimated cost per

[14] *See* Exhibit Will-Direct-2 for estimates of Program Implementation Costs by participation rate scenario.

kilowatt hour ("kWh") ranges from $0.00038 per kWh (total cost of $9.527 million) for all customers at 30 percent participation of eligible customers and increases to $0.00121 per kWh (total cost of $30.155 million) for all customers at 100 percent participation of eligible customers.[15] These per kWh costs contemplate both the regulatory asset for the program costs, as well as the regulatory asset for revenue shortfall.

65. Q. IS THE COMPANY'S COST RECOVERY PROPOSAL REASONABLE?

A. Yes. As discussed in the Commission's Order in Docket No. 17-07026, "the purpose of a regulatory asset is to acknowledge a potential liability for a utility's ratepayers and to provide a type of safety net for utilities and investors."[16] At this point, the Company has little indication as to how popular such a program as proposed would be. Considering the large swing in costs driven by the number of participants, the utilization of a regulatory asset, especially during the onset, serves to do just as the Commission previously acknowledged – protect the ratepayers by deferring a potentially large liability ***and*** the utility and its shareholders by preventing a drastic under-collection. The Commission further discussed in that Order, "[w]hile it maybe speculative a to whether and how much NV Energy may under-collect, …, fairness swings both ways. The PUCN has a legal duty to ensure NV Energy has an opportunity to earn a fair rate of return on its investment and be kept financially viable, especially as energy goals and technologies in Nevada evolve and grow."[17] If the Company's proposal is accepted, further discussions

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[15] *See* Exhibit Will-Direct-2.

[16] Docket No. 17-07026, *Order Granting in Part and Denying in Part Joint Application by NV Energy om Assembly Bill 405*, at 13 (Sept. 1, 2017).

[17] *Id.*

surrounding cost recovery would be welcomed as the program evolves and more real time recovery, through potentially a balancing account could be pursued.

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

A. Yes.

EXHIBIT NAUGHTON-DIRECT-1

STATEMENT OF QUALIFICATIONS

Jenny Naughton
Director, Regulatory Accounting & Reporting
NV Energy
6100 Neil Road
Reno, Nevada 89511-1137
(775) 834-4222

Ms. Naughton has been an employee of NV Energy since 2017, where she has spent time in the Major Accounts and Regulatory Pricing & Economic Analysis departments but transitioned to the Revenue Requirement & Regulatory Accounting group in March 2022. She has since assumed the role of Director, Regulatory Accounting & Reporting. Her responsibilities include monthly, quarterly, and annual fuel and purchased power and deferred energy recovery mechanisms and their corresponding rate development and required filings, along with the preparation of regulatory earned rate of return and revenue requirement calculations. She also oversees the preparation of various regulatory filings with both the Public Utilities Commission of Nevada ("PUCN") and the Federal Energy Regulatory Commission ("FERC"), as well all revenue accounting for the Companies.

Prior to joining the Company, Ms. Naughton worked in various finance & accounting functions across different industries and was most recently employed by KP Aviation, an aftermarket aviation component retailer, as the Controller.

Professional Experience

NV Energy, Reno, NV
Director, Regulatory Accounting & Reporting
May 2024 - Present
Revenue Requirement & FERC Manager, Revenue Requirement & Regulatory Accounting
March 2022 to May 2024

- Oversee the preparation of fuel and purchased power recovery and various deferred energy mechanisms and their required filings
- Oversee the preparation of regulatory earned rate of return and revenue requirement calculations in compliance with regulations and Commission directives for state and FERC jurisdictional filings
- Responsible for the completion of various state and FERC reporting requirements

Pricing Specialist, Regulatory Pricing & Economic Analysis
April 2021 to March 2022

- Conducted research and provided analytical support and guidance for internal and external customers
- Coordinated with several departments to gather data and perform the customer weighting factor study
- Prepared analysis and support for alternative rate options for inquiries by large customers

Major Accounts Specialist, Major Accounts
Senior Major Accounts Analyst, Major Accounts
November 2017 to April 2021

- Performed analysis of rates, market and growth trends, energy demand and usage, budgeting, billing, load profiling, and usage/cost drivers for substantial energy use customers
- Provided analysis and presentations used in the Company's large customer retention efforts
- Developed and performed initial monthly calculations of Market Price Energy and other rates
- Managed and prepared large customer contracts for standby service and gas transportation

KP Aviation, Reno, NV
Controller, Finance & Accounting
Operations Analyst, Finance & Accounting
January 2016 to November 2017

- Responsible for the preparation of the Company's financial reporting and statements
- Prepared and monitored project budgets, projections, and performance reporting
- Designed and managed the migration and implementation of new finance & accounting software

Ruby Seven Studios, Reno, NV
Finance Manager
August 2015 to December 2015

- Managed all day-to-day business operations of the company, including all accounting functions, human resources, payroll, and compliance

Klondex Mining, Reno, NV
Staff Accountant
May 2015 to August 2015

- Preparing journal entries, account reconciliations, and supporting schedules for the corporate ledger and other business units
- Maintained the daily log for ore production and prepared monthly accrual entries accordingly

Sutton Place Limited, Reno, NV
Staff Accountant
March 2013 to May 2015

- Prepared and presented quarterly and annual projections, budgets, financial statements, reconciliations, and adjusting journal entries with all supporting schedules and documentation for various clients, including the company, for a high-net worth family office
- Performed weekly cash flow statements and managed all cash transactions, accounts payable, accounts receivable, and payroll for all applicable clients

West Coast Contractors of Nevada, Inc., Reno, NV
Staff Accountant
April 2012 to March 2013

- Provided support for Operations by including job set-up, cost management, producing and analyzing projects projections and forecasts.
- Managed all project's accounts payable & receivable
- Prepared monthly adjusting journal entries, reconciliations, and quarterly and annual financial statements, with all supporting schedules and documentation

Caesars Entertainment, Las Vegas, NV
Operations Accountant, Accounts Receivable
May 2011 to March 2012

- Managed and maintained 20 hotel wholesale accounts and various other City Ledger accounts for 26 properties nationwide by applying all daily payments received, performing all necessary adjustments, and submitting all invoices on a weekly basis

Prior Testimony Before the Public Utilities Commission of Nevada

22-06014	22-09002	23-03005	23-03006	23-03007	23-06007	23-09003
24-02026	24-02027	24-03003	24-03004	24-03005	24-05041	

Education

University of Nevada, Reno
Bachelor of Science in Finance, Emphasis in Accounting, May 2011

EXHIBIT NAUGHTON-DIRECT-2

NEVADA POWER COMPANY
d/b/a NV Energy
Greenlink CWIP in Ratebase Impact To Customers, per NRS
For The Twelve Months Ended September 30, 2024
(In Thousands)

Ln	(a) Rate Schedule		(b) Annualized kWh	(c) Revenues Proposed Rate - No CWIP	(d) Revenues Proposed Rate - CWIP	(e) [(d)-(c)] Change - Proposed vs Present Dollar	(f) [((d)-(c))/(c) *100] Change - Proposed vs Present Percent	(g) Annualized Customer Count	(h) Proposed Monthly INC/(DECR)	Ln
1	Residential - Single Family	RS	6,565,462,070	$ 956,604	$ 968,750	$ 12,146	1.27 %	5,954,088	$ 2.04	1
2	Residential - Multi-Family	RM	2,159,281,303	292,540	295,606	3,066	1.05 %	3,430,020	0.89	2
3	Residential - Large Single Family	LRS	35,162,020	4,265	4,331	66	1.55 %	2,351	28.07	3
4	Residential - Single Family - Flexpay	RS-FLEX	147,821,235	21,703	21,976	273	1.26 %	127,056	2.15	4
5	Residential - Multi-Family - Flexpay	RM-FLEX	108,326,851	14,750	14,904	154	1.04 %	139,776	1.10	5
6	Residential - Single Family - Net Metering	RS-NEM	578,910,284	110,379	111,450	1,071	0.97 %	1,283,940	0.83	6
7	Residential - Multi-Family - Net Metering	RM-NEM	4,657,408	680	686	6	0.88 %	11,616	0.52	7
8	Residential - Large Single Family - Net Metering	LRS-NEM	504,467	88	88	-	- %	240	-	8
9	Residential - Large Single Family - Flexpay	LRS-FLEX	-	-	-	-	- %	-	-	9
10	Total Residential - Non-TOU		9,600,125,638	1,401,009	1,417,791	16,782	1.20 %	10,949,087	1.53	10
11										11
12	Residential - Single Family - TOU	ORS-TOU	31,898,967	4,512	4,567	55	1.22 %	26,904	2.04	12
13	Residential - Single Family - TOU - Net Metering	ORS-NEM	8,690,909	2,080	2,119	39	1.88 %	16,055	2.43	13
14	Residential - Single Family - TOU - EVRR	ORS-TOU EVRR	80,040,495	11,303	11,453	150	1.33 %	50,472	2.97	14
15	Residential - Single Family - TOU - EVRR - Net Metering	ORS-NEM EVRR	21,832,529	3,588	3,629	41	1.14 %	26,796	1.53	15
16	Residential - Multi-Family - TOU	ORM-TOU	1,870,342	257	260	3	1.17 %	3,060	0.98	16
17	Residential - Multi-Family - TOU - Net Metering	ORM-NEM	5,847	-	-	-	- %	24	-	17
18	Residential - Single Family - TOU Critical Peak	ORS-TOU CPP	279,133	33	34	1	3.03 %	65	15.38	18
19	Residential - Single Family - TOU Critical Peak - Net Metering	ORS-NEM CPP	3,479	-	-	-	- %	6	-	19
20	Residential - Multi-Family - TOU - EVRR	ORM-TOU EVRR	2,555,468	323	327	4	1.24 %	2,616	1.53	20
21	Residential - Multi-Family - TOU - EVRR - Net Metering	ORM-NEM EVRR	25,069	3	3	-	- %	36	-	21
22	Residential - Multi-Family - TOU - Daily Demand	ORM-TOU DDP	7,208	1	1	-	- %	8	-	22
23	Residential - Large Single Family - TOU - EVRR	OLRS-TOU EVRR	321,110	38	39	1	2.63 %	24	41.67	23
24	Total Residential - TOU		147,530,556	22,138	22,432	294	1.33 %	126,066	2.33	24
25										25
26	Residential - Private Area Lighting	RS-PAL	546,732	69	67	(2)	(2.90)%	6,876	(0.29)	26
27										27
28	**Total Residential**		**9,748,202,926**	**$ 1,423,216.00**	**$ 1,440,290.00**	**$ 17,074.00**	**1.20 %**	**11,082,029**	**$ 3.57**	28
29										29
30	General Service	GS	594,785,365	$ 69,823	$ 70,505	$ 682	0.98 %	951,108	$ 0.72	30
31	General Service - Net Metering	GS-NEM	2,485,899	249	252	3	1.20 %	1,788	1.68	31
32	General Service - TOU	OGS-TOU	26,864,136	2,714	2,727	13	0.48 %	31,860	0.41	32
33	General Service - TOU EVRR	OGS-TOU EVRR	18,545	3	3	-	- %	48	-	33
34	General Service - Private Area Lighting	GS-PAL	2,133,900	253	249	(4)	(1.58)%	23,772	(0.17)	34
35	Total General Service		626,287,845	73,042	73,736	694	0.95 %	1,008,576	0.69	35
36										36
37	Large General Service - 1	LGS-1	4,318,766,609	417,354	422,781	5,427	1.30 %	421,236	12.88	37
38	Large General Service - 1 - Net Metering	LGS-1 NEM	79,200,054	8,241	8,353	112	1.36 %	4,764	23.51	38
39	Large General Service - 1 - SSR	SSR-III LGS-1	1,155,426	124	126	2	1.61 %	48	41.67	39
40	Large General Service - 1 - TOU	OLGS-1 TOU	122,638,709	10,989	11,124	135	1.23 %	11,040	12.23	40
41	Total Large General Service - 1		4,521,760,798	436,708	442,384	5,676	1.30 %	437,088	12.99	41
42										42
43	Large General Service - 2: Primary	LGS-2P	58,582,191	5,325	5,354	29	0.54 %	264	109.85	43
44	Large General Service - 2: Secondary	LGS-2S	2,548,457,427	233,225	235,818	2,593	1.11 %	15,312	169.34	44
45	Large General Service - 2: Transmission	LGS-2T	-	-	-	-	- %	-	-	45
46	Large General Service - 2: Transmission - LSR	LSR-I LGS-2T	9,678,986	923	931	8	0.87 %	60	133.33	46
47	Large General Service - 2: Secondary EVCCR	LGS-2S EVCCR	17,773,190	1,867	1,889	22	1.18 %	180	122.22	47
48	Total Large General Service - 2		2,634,491,794	$ 241,340	$ 243,992	$ 2,652	1.10 %	15,816	$ 167.68	48

NEVADA POWER COMPANY
d/b/a NV Energy
Greenlink CWIP in Ratebase Impact To Customers, per NRS
For The Twelve Months Ended September 30, 2024
(In Thousands)

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	
						[(d)-(c)]	[((d)-(c))/(c) *100]		Proposed	
			Annualized	Revenues		Change - Proposed vs Present		Annualized	Monthly	
Ln	Rate Schedule		kWh	Proposed Rate - No CWIP	Proposed Rate - CWIP	Dollar	Percent	Customer Count	INC/(DECR)	Ln
1	Large General Service - 3: Primary	LGS-3P	1,500,729,636	$ 134,850	$ 135,878	$ 1,028	0.76 %	1,260	$ 815.87	1
2	Large General Service - 3: Secondary	LGS-3S	803,476,991	70,254	71,041	787	1.12 %	1,596	493.11	2
3	Large General Service - 3: Transmission	LGS-3T	284,330,980	24,918	25,013	95	0.38 %	60	1,583.33	3
4	Large General Service - 3: Primary - HLF	OLGS-3P-HLF	288,999,735	23,860	24,039	179	0.75 %	120	1,491.67	4
5	Large General Service - 3: Primary - LSR	LSR-II LGS-3P	27,849,839	2,616	2,637	21	0.80 %	36	583.33	5
6	Large General Service - 3: Transmission - LSR	LSR-II LGS-3T	102,556,841	9,311	9,363	52	0.56 %	84	619.05	6
7	Total Large General Service - 3		3,007,944,022	265,809	267,971	2,162	0.81 %	3,156	685.04	7
8										8
9	Total Large General Service - 1,2 & 3		10,164,196,614	943,857	954,347	10,490	1.11 %	456,060	23.00	9
10										10
11	Market Place Energy	MPE	798,176,757	50,885	51,065	180	0.35 %	432	416.67	11
12										12
13	Street Lighting	SL	121,573,220	12,521	12,201	(320)	(2.56)%	7,224	(44.30)	13
14										14
15	LGS - Water Pumping -2: Primary	LGS-2P-WP	12,560,968	1,071	1,069	(2)	(0.19)%	108	(18.52)	15
16	LGS - Water Pumping -2: Secondary	LGS-2S-WP	25,032,927	2,621	2,626	5	0.19 %	324	15.43	16
17	Total LGS - Water Pumping -2		37,593,895	3,692	3,695	3	0.08 %	432	6.94	17
18										18
19	LGS - Water Pumping -3: Primary	LGS-3P-WP	16,526,677	1,294	1,289	(5)	(0.39)%	60	(83.33)	19
20	LGS - Water Pumping -3: Secondary	LGS-3S-WP	4,500,897	320	315	(5)	(1.56)%	24	(208.33)	20
21	Total LGS - Water Pumping -3		21,027,574	1,614	1,604	(10)	(0.62)%	84	(119.05)	21
22										22
23	Total LGS - Water Pumping - 2 & 3		58,621,469	5,306	5,299	(7)	(0.13)%	516	(13.57)	23
24										24
25	**Total Non-Residential**		**11,768,855,905**	**1,085,611**	**1,096,648**	**11,037**	**1.02 %**	**1,472,808**	**7.49**	25
26										26
27	**Total - all classes**		**21,517,058,831**	**$ 2,508,827**	**$ 2,536,938**	**$ 28,111**	**1.12 %**	**12,554,837**	**$ 2.24**	27
28										28
29	General Service - DOS	GS DOS	82,918	$ 4	$ 4	$ -	- %	156	$ -	29
30	Large General Service - 1 - DOS	LGS-1 DOS	8,672,488	129	131	2	1.55 %	264	7.58	30
31	Large General Service - 2: Primary - DOS	LGS-2P DOS	8,431,837	124	121	(3)	(2.42)%	24	(125.00)	31
32	Large General Service - 2: Secondary - DOS	LGS-2S DOS	75,841,035	888	896	8	0.90 %	288	27.78	32
33	Large General Service - 2: Transmission - DOS	LGS-2T DOS	-	-	-	-	- %	-	-	33
34	Large General Service - 3: Primary - DOS	LGS-3P DOS	1,478,384,759	16,825	16,648	(177)	(1.05)%	636	(278.30)	34
35	Large General Service - 3: Secondary - DOS	LGS-3S DOS	94,516,144	1,071	1,087	16	1.49 %	168	95.24	35
36	Large General Service - 3: Transmission - DOS	LGS-3T DOS	630,316,111	5,145	4,878	(267)	(5.19)%	144	(1,854.17)	36
37	Large General Service - X: Primary - DOS	LGS-XP DOS	278,848,028	4,884	4,851	(33)	(0.68)%	24	(1,375.00)	37
38	Large General Service - X: Secondary - DOS	LGS-XS DOS	8,063,845	140	142	2	1.43 %	-	-	38
39	Large General Service - X: Transmission - DOS	LGS-XT DOS	161,079,724	1,336	1,267	(69)	(5.16)%	12	(5,750.00)	39
40	LGS - Water Pumping -2: Secondary - DOS	LGS-2S-WP DOS	2,958,403	66	66	-	- %	24	-	40
41	LGS - Water Pumping -2: Transmission - DOS	LGS-2T-WP DOS	2,102,874	35	34	(1)	(2.86)%	12	(83.33)	41
42	LGS - Water Pumping -3: Primary - DOS	LGS-3P-WP DOS	70,439,777	907	848	(59)	(6.50)%	96	(614.58)	42
43	LGS - Water Pumping -3: Secondary - DOS	LGS-3S-WP DOS	25,595,953	295	268	(27)	(9.15)%	96	(281.25)	43
44	LGS - Water Pumping -3: Transmission - DOS	LGS-3T-WP DOS	50,386,239	528	500	(28)	(5.30)%	48	(583.33)	44
45	Total DOS		2,895,720,135	32,377	31,741	(636)	(1.96)%	1,992	(319.28)	45
46										46
47	**Total - all classes with Distribution Only Service**		**24,412,778,966**	**$ 2,541,204**	**$ 2,568,679**	**$ 27,475**	**1.08 %**	**12,556,829**	**$ 2.19**	47
48										48
49	Notes:									49
50	a) kWh sales and revenues do not include unbilled									50

NEVADA POWER COMPANY
d/b/a NV Energy
Greenlink CWIP in Ratebase Impact To Customers, ECIC
For The Twelve Months Ended September 30, 2024
(In Thousands)

Ln	(a) Rate Schedule		(b) Annualized kWh	(c) Revenues Proposed Rate - No CWIP	(d) Revenues Proposed Rate - CWIP	(e) [(d)-(c)] Change - Proposed vs Present Dollar	(f) [((d)-(c))/(c) *100] Change - Proposed vs Present Percent	(g) Annualized Customer Count	(h) Proposed Monthly INC/(DECR)	Ln
1	Residential - Single Family	RS	6,565,462,070	$ 965,021	$ 977,167	$ 12,146	1.26 %	5,954,088	$ 2.04	1
2	Residential - Multi-Family	RM	2,159,281,303	296,254	299,104	2,850	0.96 %	3,430,020	0.83	2
3	Residential - Large Single Family	LRS	35,162,020	4,305	4,365	60	1.39 %	2,351	25.52	3
4	Residential - Single Family - Flexpay	RS-FLEX	147,821,235	21,891	22,165	274	1.25 %	127,056	2.16	4
5	Residential - Multi-Family - Flexpay	RM-FLEX	108,326,851	14,937	15,080	143	0.96 %	139,776	1.02	5
6	Residential - Single Family - Net Metering	RS-NEM	578,910,284	111,787	112,858	1,071	0.96 %	1,283,940	0.83	6
7	Residential - Multi-Family - Net Metering	RM-NEM	4,657,408	688	694	6	0.87 %	11,616	0.52	7
8	Residential - Large Single Family - Net Metering	LRS-NEM	504,467	88	89	1	1.14 %	240	4.17	8
9	Residential - Large Single Family - Flexpay	LRS-FLEX	-	-	-	-	- %	-	-	9
10	Total Residential - Non-TOU		9,600,125,638	1,414,971	1,431,522	16,551	1.17 %	10,949,087	1.51	10
11										11
12	Residential - Single Family - TOU	ORS-TOU	31,898,967	4,554	4,610	56	1.23 %	26,904	2.08	12
13	Residential - Single Family - TOU - Net Metering	ORS-NEM	8,690,909	2,111	2,149	38	1.80 %	16,055	2.37	13
14	Residential - Single Family - TOU - EVRR	ORS-TOU EVRR	80,040,495	11,428	11,579	151	1.32 %	50,472	2.99	14
15	Residential - Single Family - TOU - EVRR - Net Metering	ORS-NEM EVRR	21,832,529	3,625	3,665	40	1.10 %	26,796	1.49	15
16	Residential - Multi-Family - TOU	ORM-TOU	1,870,342	260	263	3	1.15 %	3,060	0.98	16
17	Residential - Multi-Family - TOU - Net Metering	ORM-NEM	5,847	-	-	-	- %	24	-	17
18	Residential - Single Family - TOU Critical Peak	ORS-TOU CPP	279,133	34	34	-	- %	65	-	18
19	Residential - Single Family - TOU Critical Peak - Net Metering	ORS-NEM CPP	3,479	-	-	-	- %	6	-	19
20	Residential - Multi-Family - TOU - EVRR	ORM-TOU EVRR	2,555,468	327	331	4	1.22 %	2,616	1.53	20
21	Residential - Multi-Family - TOU - EVRR - Net Metering	ORM-NEM EVRR	25,069	3	4	1	33.33 %	36	27.78	21
22	Residential - Multi-Family - TOU - Daily Demand	ORM-TOU DDP	7,208	1	1	-	- %	8	-	22
23	Residential - Large Single Family - TOU - EVRR	OLRS-TOU EVRR	321,110	39	39	-	- %	24	-	23
24	Total Residential - TOU		147,530,556	22,382	22,675	293	1.31 %	126,066	2.32	24
25										25
26	Residential - Private Area Lighting	RS-PAL	546,732	68	67	(1)	(1.47)%	6,876	(0.15)	26
27										27
28	**Total Residential**		**9,748,202,926**	**1,437,421**	**1,454,264**	**16,843**	**1.17 %**	**11,082,029**	**3.69**	28
29										29
30	General Service	GS	594,785,365	70,737	71,348	611	0.86 %	951,108	0.64	30
31	General Service - Net Metering	GS-NEM	2,485,899	253	256	3	1.19 %	1,788	1.68	31
32	General Service - TOU	OGS-TOU	26,864,136	2,741	2,750	9	0.33 %	31,860	0.28	32
33	General Service - TOU EVRR	OGS-TOU EVRR	18,545	3	3	-	- %	48	-	33
34	General Service - Private Area Lighting	GS-PAL	2,133,900	251	248	(3)	(1.20)%	23,772	(0.13)	34
35	Total General Service		626,287,845	73,985	74,605	620	0.84 %	1,008,576	0.61	35
36										36
37	Large General Service - 1	LGS-1	4,318,766,609	420,455	426,054	5,599	1.33 %	421,236	13.29	37
38	Large General Service - 1 - Net Metering	LGS-1 NEM	79,200,054	8,305	8,421	116	1.40 %	4,764	24.35	38
39	Large General Service - 1 - SSR	SSR-III LGS-1	1,155,426	125	127	2	1.60 %	48	41.67	39
40	Large General Service - 1 - TOU	OLGS-1 TOU	122,638,709	11,064	11,203	139	1.26 %	11,040	12.59	40
41	Total Large General Service - 1		4,521,760,798	439,949	445,805	5,856	1.33 %	437,088	13.40	41
42										42
43	Large General Service - 2: Primary	LGS-2P	58,582,191	5,341	5,373	32	0.60 %	264	121.21	43
44	Large General Service - 2: Secondary	LGS-2S	2,548,457,427	234,717	237,202	2,485	1.06 %	15,312	162.29	44
45	Large General Service - 2: Transmission	LGS-2T	-	-	-	-	- %	-	-	45
46	Large General Service - 2: Transmission - LSR	LSR-I LGS-2T	9,678,986	926	934	8	0.86 %	60	133.33	46
47	Large General Service - 2: Secondary EVCCR	LGS-2S EVCCR	17,773,190	1,879	1,899	20	1.06 %	180	111.11	47
48	Total Large General Service - 2		2,634,491,794	242,863	245,408	2,545	1.05 %	15,816	160.91	48

NEVADA POWER COMPANY
d/b/a NV Energy
Greenlink CWIP in Ratebase Impact To Customers, ECIC
For The Twelve Months Ended September 30, 2024
(In Thousands)

Ln	(a) Rate Schedule		(b) Annualized kWh	(c) Revenues: Proposed Rate - No CWIP	(d) Revenues: Proposed Rate - CWIP	(e) [(d)-(c)] Change - Proposed vs Present: Dollar	(f) [((d)-(c))/(c) *100] Change - Proposed vs Present: Percent	(g) Annualized Customer Count	(h) Proposed Monthly INC/(DECR)	Ln
1	Large General Service - 3: Primary	LGS-3P	1,500,729,636	$ 135,410	$ 136,449	$ 1,039	0.77 %	1,260	$ 824.60	1
2	Large General Service - 3: Secondary	LGS-3S	803,476,991	70,694	71,439	745	1.05 %	1,596	466.79	2
3	Large General Service - 3: Transmission	LGS-3T	284,330,980	24,923	25,043	120	0.48 %	60	2,000.00	3
4	Large General Service - 3: Primary - HLF	OLGS-3P-HLF	288,999,735	23,946	24,125	179	0.75 %	120	1,491.67	4
5	Large General Service - 3: Primary - LSR	LSR-II LGS-3P	27,849,839	2,627	2,649	22	0.84 %	36	611.11	5
6	Large General Service - 3: Transmission - LSR	LSR-II LGS-3T	102,556,841	9,316	9,379	63	0.68 %	84	750.00	6
7	Total Large General Service - 3		3,007,944,022	266,916	269,084	2,168	0.81 %	3,156	686.95	7
8										8
9	Total Large General Service - 1,2 & 3		10,164,196,614	949,728	960,297	10,569	1.11 %	456,060	23.17	9
10										10
11	Market Place Energy	MPE	798,176,757	50,739	50,973	234	0.46 %	432	541.67	11
12										12
13	Street Lighting	SL	121,573,220	12,364	12,121	(243)	(1.97)%	7,224	(33.64)	13
14										14
15	LGS - Water Pumping -2: Primary	LGS-2P-WP	12,560,968	1,071	1,070	(1)	(0.09)%	108	(9.26)	15
16	LGS - Water Pumping -2: Secondary	LGS-2S-WP	25,032,927	2,625	2,630	5	0.19 %	324	15.43	16
17	Total LGS - Water Pumping -2		37,593,895	3,696	3,700	4	0.11 %	432	9.26	17
18										18
19	LGS - Water Pumping -3: Primary	LGS-3P-WP	16,526,677	1,290	1,287	(3)	(0.23)%	60	(50.00)	19
20	LGS - Water Pumping -3: Secondary	LGS-3S-WP	4,500,897	318	314	(4)	(1.26)%	24	(166.67)	20
21	Total LGS - Water Pumping -3		21,027,574	1,608	1,601	(7)	(0.44)%	84	(83.33)	21
22										22
23	Total LGS - Water Pumping - 2 & 3		58,621,469	5,304	5,301	(3)	(0.06)%	516	(5.81)	23
24										24
25	**Total Non-Residential**		**11,768,855,905**	**1,092,120**	**1,103,297**	**11,177**	**1.02 %**	**1,472,808**	**7.59**	25
26										26
27	**Total - all classes**		**21,517,058,831**	**2,529,541**	**2,557,561**	**28,020**	**1.11 %**	**12,554,837**	**2.23**	27
28										28
29	General Service - DOS	GS DOS	82,918	4	4	-	- %	156	-	29
30	Large General Service - 1 - DOS	LGS-1 DOS	8,672,488	132	134	2	1.52 %	264	7.58	30
31	Large General Service - 2: Primary - DOS	LGS-2P DOS	8,431,837	123	121	(2)	(1.63)%	24	(83.33)	31
32	Large General Service - 2: Secondary - DOS	LGS-2S DOS	75,841,035	894	899	5	0.56 %	288	17.36	32
33	Large General Service - 2: Transmission - DOS	LGS-2T DOS	-	-	-	-	- %	-	-	33
34	Large General Service - 3: Primary - DOS	LGS-3P DOS	1,478,384,759	16,865	16,702	(163)	(0.97)%	636	(256.29)	34
35	Large General Service - 3: Secondary - DOS	LGS-3S DOS	94,516,144	1,081	1,092	11	1.02 %	168	65.48	35
36	Large General Service - 3: Transmission - DOS	LGS-3T DOS	630,316,111	4,965	4,752	(213)	(4.29)%	144	(1,479.17)	36
37	Large General Service - X: Primary - DOS	LGS-XP DOS	278,848,028	4,898	4,867	(31)	(0.63)%	24	(1,291.67)	37
38	Large General Service - X: Secondary - DOS	LGS-XS DOS	8,063,845	142	143	1	0.70 %	-	-	38
39	Large General Service - X: Transmission - DOS	LGS-XT DOS	161,079,724	1,287	1,232	(55)	(4.27)%	12	(4,583.33)	39
40	LGS - Water Pumping -2: Secondary - DOS	LGS-2S-WP DOS	2,958,403	66	65	(1)	(1.52)%	24	(41.67)	40
41	LGS - Water Pumping -2: Transmission - DOS	LGS-2T-WP DOS	2,102,874	34	33	(1)	(2.94)%	12	(83.33)	41
42	LGS - Water Pumping -3: Primary - DOS	LGS-3P-WP DOS	70,439,777	868	822	(46)	(5.30)%	96	(479.17)	42
43	LGS - Water Pumping -3: Secondary - DOS	LGS-3S-WP DOS	25,595,953	280	259	(21)	(7.50)%	96	(218.75)	43
44	LGS - Water Pumping -3: Transmission - DOS	LGS-3T-WP DOS	50,386,239	504	480	(24)	(4.76)%	48	(500.00)	44
45	Total DOS		2,895,720,135	32,143	31,605	(538)	(1.67)%	1,992	(270.08)	45
46										46
47	**Total - all classes with Distribution Only Service**		**24,412,778,966**	**$ 2,561,684**	**$ 2,589,166**	**$ 27,482**	**1.07 %**	**12,556,829**	**$ 2.19**	47
48										48

49 Notes: 49
50 a) kWh sales and revenues do not include unbilled 50

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, JENNY NAUGHTON, states that she 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 her knowledge and belief; and that if asked the questions appearing therein, her answers thereto would, under oath, be the same.

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

Date: February 14, 2025

Jenny Naughton

Jenny Naughton

MATTHEW VALENTIC

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 25-02___
2025 General Rate Case

Prepared Direct Testimony of

Matthew Valentic

Revenue Requirement

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

A. My name is Matthew Valentic. My current position is Revenue Requirement and Federal Energy Regulatory Commission ("FERC") Manager for Nevada Power d/b/a NV Energy ("Nevada Power" or the "Company") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra," and together with Nevada Power, the "Companies"). My business address is 6100 Neil Road in Reno, Nevada. I am filing testimony on behalf of Nevada Power.

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

A. I graduated from the University of Nevada, Reno with a bachelor's degree in mathematics and obtained master's degrees in accountancy and business administration. I have been employed by the Companies since 2017, with most of my time spent in the Revenue Accounting department, of which my duties included the preparation of Statement J for both Nevada Power and Sierra, Exhibit G in support of the quarterly Deferred Energy Accounting Adjustment ("DEAA") filings, and other projects. I have since assumed the role of Revenue Requirement

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and FERC Manager in May 2024. **Exhibit Valentic-Direct-1** contains additional information regarding my qualifications.

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

A. As Revenue Requirement and FERC Manager, my responsibilities include the oversight of the preparation of the fuel and purchased power recovery rates and various deferred energy mechanisms, along with the regulatory earned rate of return and revenue requirement calculations.

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

A. Yes. I have previously testified before the Commission in Sierra's 2022 general rate case ("GRC") filing, Docket No. 22-06014, Nevada Power's 2023 GRC, Docket No. 23-06007, and Sierra's 2024 GRCs, Docket Nos. 24-02026 and 24-02027.

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

A. In Section II, my testimony supports the following Statements and Schedules:

- Statement G – Summary of Rate Base:
  - Schedule G-1 – Plant in Service Summary;
  - Schedule G-2 – Accumulated Provision of Depreciation Summary;
  - Schedule G-4 – Thirteen Month Balances of Fuel, Materials and Supplies, and prepayments for the Test Period ended September 30, 2024;
  - Schedule G-5 – Cash Working Capital Calculation.
- Statement K – Operation and Maintenance Expense.

   - Schedule K-1 – Operations and Maintenance Expenses by Component.
- Statement L – Depreciation and Amortization Expense.
- Statement N – Departmental and Jurisdictional Cost of Service Study for the Twelve Months ended September 30, 2024.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibits:

Exhibit Valentic-Direct-1 Statement of Qualifications

Exhibit Valentic-Direct-2 Cost Allocation Methodology

II. STATEMENTS AND SCHEDULES

7. Q. PLEASE DESCRIBE STATEMENT G AND SCHEDULES G-1, G-2, G-4 AND G-5.

A. Statement G is a summary of total electric rate base components for the test period ending September 30, 2024 ("Test Period"), estimated for both the certification period ending February 28, 2025 ("Certification Period") and the Expected Change in Circumstance ("ECIC") period ending September 12, 2025. As a summary, Statement G pulls together information from subordinate Schedules G-1, G-2, G-4 and G-5. I co-sponsor Schedules G-1 and G-2 with Christina Hanshew, who is responsible for the plant accounting function at Nevada Power.

- Schedule G-1 summarizes the balances and activity for plant-in-service by functional area (i.e., production, transmission, distribution, general and intangible plant) as recorded and adjusted for the Test Period and estimated for the Certification Period.

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- Schedule G-2 summarizes the balances and activity in accumulated depreciation, also by functional area, as recorded and adjusted through the Test Period and estimated for the Certification Period.
- Schedule G-4 summarizes the 13-month average balances of fuel, materials and supplies and prepayments recorded for the Test Period.
- Schedule G-5 reflects the recorded Nevada jurisdictional Cash Working Capital for the Test Period and estimated for the Certification Period. Cash working capital is a component of rate base representing the cash required to meet the utility's current obligations. A standard methodology for calculating cash working capital is to perform a detailed lead/lag study that measures the amount of time ("Expense Lead") before expenses must be paid and the amount of time ("Revenue Lag") before revenues are received. A lead/lag study provides a measurement of the cash needed to operate the business. A new lead/lag study was performed by Nevada Power witness Harold Walker III to determine the cash working capital allowance. The results of Mr. Walker's analysis are reflected in Statement H.

8. Q. PLEASE DESCRIBE STATEMENT K, OPERATIONS AND MAINTENANCE EXPENSE.

A. This statement is co-sponsored with Daniel Morley. Statement K is a seven-page statement. The first page depicts the Company's total recorded operations and maintenance ("O&M") expense for the Test Period, by functional classifications of primary accounts. The first page also reflects a summary of Statement N adjustments and the additions of certification adjustments. Pages two, four and six comprise monthly recorded expenses by primary accounts, grouped into their functional classifications. Pages three, five and seven show the O&M amounts starting with recorded data, Statement N regulatory adjustments, and conclude with the addition of certification adjustments and ECIC adjustments.

9. Q. PLEASE DESCRIBE SCHEDULE K-1, ANALYSIS OF LABOR COSTS.

A. This schedule is also co-sponsored with Mr. Morley. Schedule K-1 categorizes the recorded O&M expenses reported in Statement K into labor expense and other expenses. Page one begins with recorded data, adds in Statement N regulatory adjustments, and concludes with the addition of certification adjustments. Page two shows the recorded Test Period expenses by month by functional classifications.

10. Q. PLEASE DESCRIBE STATEMENT L.

A. Statement L provides a summary of the Company's plant depreciation and amortization expense by functional classifications through the Test Period, the Certification Period, and the ECIC period. This statement is also co-sponsored with Ms. Hanshew.

11. Q. PLEASE DESCRIBE THE INFORMATION CONTAINED IN STATEMENT N.

A. Statement N shows the Company's adjusted and allocated results of operations for the 12 months ending September 30, 2024. Statement N will not be updated at certification, unless there is a material change required to the allocators.

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Statement N illustrates the flow of data starting with recorded numbers and finishing with the jurisdictional electric amounts. Each page includes:

- The recorded values from Nevada Power's books and records,

- Adjustments to reflect regulatory treatment that is not otherwise recorded on the books, and
- The allocation of Nevada Power's electric results of operations adjusted to reflect regulatory treatment not otherwise recorded on the books between Nevada and FERC jurisdictions.

12. Q. PLEASE DESCRIBE THE NEVADA JURISDICTIONAL PORTION OF STATEMENT N.

A. The results of operations and rate of return calculations for Nevada Power's Nevada and Federal electric jurisdictions are shown on Statement N. As in prior general rate review filings, the allocation methodology used in this schedule closely follows the methodology recommended by the National Association of Regulatory Utility Commissioners in its Cost Allocation Manual and is more fully set forth in **Exhibit Valentic-Direct-2**, with one minor adjustment as discussed next.

13. Q. WHAT ADJUSTMENT WAS MADE TO THE RECORDED PERIOD ALLOCATORS IN STATEMENT N?

A. All known long-term firm transmission contracts that are expected to change prior to the rate effective date of October 1, 2025, were normalized to the new contract load to align transmission demand more closely with the rate effective period. Similarly, contracts that are due to end prior to the beginning of the rate effective period were removed from the allocation. This methodology is consistent with adjustments that were made to Statement N in Nevada Power's last general rate review, Docket No. 23-06007 and in Sierra's general rate review Docket No. 24-02026.

This adjustment to the retail transmission allocator causes it to increase from 81.851 percent to 82.687 percent, slightly increasing the Nevada jurisdictional Test Period costs.

14. Q. DID THE COMPANY COMPLY WITH DIRECTIVES 6 AND 7 FROM DOCKET NO. 23-06007 TO MEET AND CONFER WITH THE REGULATORY OPERATIONS STAFF REGARDING THE TRANSMISSION ALLOCATOR PRIOR TO FILING THIS GRC?

A. Yes. The transmission allocator was discussed in a meeting with the Regulatory Operations Staff on January 14, 2025.

15. Q. WERE ANY OTHER CHANGES MADE TO STATEMENT N FOR THIS FILING COMPARED TO THE LAST GRC PROCEEDING?

A. Yes. In previous GRCs, the updated cash working capital calculation from Schedule G-5 was included in Statement N. In this case, the update to cash working capital presented on Schedule G-5 is not included in Statement N but instead included in Schedule H-CERT-04 and H-ECIC-04. This has no impact on the calculation.

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

A. Yes.

EXHIBIT VALENTIC-DIRECT-1

STATEMENT OF QUALIFICATIONS
Matthew Valentic
Revenue Requirement and FERC Manager
NV Energy
6100 Neil Rd.
Reno, NV 89511

Matthew Valentic has been with NV Energy in various capacities since 2017, primarily focused on recording, analyzing, and reporting revenue. Mr. Valentic has prepared statements, reports, and data responses for regulators and interveners.

EMPLOYMENT HISTORY

May 2024 to present **NV Energy** ***Revenue Requirement and FERC Manager***
Manage the preparation of fuel and purchased power recovery and various deferred energy mechanisms and their required filings. Oversee the preparation of regulatory earned rate of return and revenue requirement calculations in compliance with regulations and Commission directives for state and FERC jurisdictional filings. Responsible for the completion of various state and FERC reporting requirements.

2020 to May 2024 **NV Energy** ***Revenue and Regulatory Accounting Manager***
Direct staff in the performance of various corporate and regulatory functions, including preparation of regulatory statements, adjustments, and analysis. Direct implementation of appropriate accounting procedures to comply with regulatory orders and developments. Oversee accounting and reporting for revenue and responsible for preparation of the internal component of tariff and ensuring proper accounting for rate changes.

2019 to 2020 **NV Energy** ***Senior Revenue and Regulatory Analyst***
Reviewed and analyzed revenue data, recorded journal entries, and identified revenue related issues. Prepared estimates of monthly unbilled revenue and sales. Prepared statements and schedules for reporting to the Public Utilities Commission of Nevada ("PUCN"). Led process improvement for the revenue and regulatory team and responsible for the internal component of tariff.

2017 to 2019 **NV Energy** ***Revenue and Regulatory Analyst***
Reviewed and analyzed revenue data, recorded journal entries, and identified revenue related issues. Prepared estimates of monthly unbilled revenue and sales. Assisted in the preparation of statements and schedules for reporting to the PUCN.

2010 to 2017 **Verizon Wireless** ***Solution Specialist***

2008 to 2010 **Peace Corps** ***Peace Corps Volunteer – Math Teacher***

2005 to 2008 **Enterprise Rent-A-Car** ***Management Assistant***

EDUCATION

University of Nevada, Reno
Master of Accountancy – 2017
University of Phoenix
Master of Business Administration – 2014
University of Nevada, Reno
BA in Mathematics – 2005

EXHIBIT VALENTIC-DIRECT-2

NEVADA POWER COMPANY
d/b/a NV Energy
COST ALLOCATION METHODOLOGY

1. Nevada Power Company ("Nevada Power") is a regulated public utility engaged primarily in the generation, purchase, transmission, distribution and sales of electricity in Nevada. The electric utility department operates under the jurisdiction of the Public Utilities Commission of Nevada ("PUCN") and the Federal Energy Regulatory Commission ("FERC").

2. Nevada Power maintains its accounting records in accordance with the uniform system of accounts for such utilities as prescribed by Code of Federal Regulations ("CFR").

3. In its "Preface" to the 1973 National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual, the Subcommittee on cost allocation states:

> A uniform method of cost allocation for electric utilities operating under the jurisdiction of more than one regulatory agency is required if neither the public or the utility is to suffer by reason of inconsistent or incompatible action. A reasonable method should be agreed upon by the several regulatory jurisdictions and implemented by the utility in each area. The sum of the jurisdictional pieces allocated by a reasonable method should equal the jurisdictional total -no more and no less.

The allocation methodology described herein has been submitted to and accepted by the PUCN and closely follows the methodology recommended by NARUC.

4. Under the allocation methodology described herein, costs are classified into the basic components demand, energy, customer, or some composite thereof, for allocation purposes. Demand-related costs are those costs which relate to peak usage of electricity. These costs are generally referred to as fixed costs because they remain constant regardless of the amount of energy delivered by the system. Energy-related costs are those which vary directly with the quantity of energy produced and delivered. Customer-related costs are those which vary with the number of customers served.

5. These three dimensions, demand, energy and customers, provide the basis for the jurisdictional allocation of the majority of the Electric Department costs, both capital and operating. The jurisdictional responsibility for demand-related costs is based on the contribution to twelve monthly peaks. Transmission Demand is the sum of twelve monthly transmission system loads and Production demand is the sum of the twelve monthly system peaks. The jurisdictional responsibility for energy-related costs is determined by the sum of twelve months recorded sales and their relationship to output to lines for the same period. Because Nevada Power is a retail energy provider solely within the State of Nevada, customer-

related costs are directly assigned to the Nevada Retail jurisdiction. These ratios are primary allocation ratios and the combination of two or more of these primary ratios are a composite ratio.

6. All costs do not fall neatly into the three classifications listed above. Generally, such costs are allocated only after all basic costs have been apportioned to the appropriate jurisdiction. These costs fall into a category which follows proportionately the direct initial allocation of functional costs. Allocation ratios calculated as the sum of specific previously allocated accounts are secondary ratios.

7. Net Production Plant and related operating expense for steam and other power production, with the exception of fuel, is classified as demand-related. Other power supply expenses, excluding energy costs for purchased power, are also demand- related. The Production Demand allocator is contribution to system peak. Fuel, energy costs for purchased power and all production maintenance expense are energy-related.

8. Net Transmission Plant, its associated operation and maintenance expense (with the exception of Account No. 565), and depreciation expense are classified as demand-related. The Transmission allocation is based on the Transmission System Load as described in the NV Energy Operating Companies Open Access Transmission Tariff ("OATT"). Transmission System Load is the sum of the contribution to peak of all Network Customers (including Nevada Power's native load) plus the contract demands of all long-term firm point-to-point customers. The four coincident peaks of June, July, August, and September ("4CP") are used to calculate the transmission demand allocator. Short-term and non-firm transmission transactions are treated as revenue credits. Account No. 565, Transmission by others, is associated with Account No. 555, Purchased Power, and is recovered in Deferred Energy Accounting.

9. Net Distribution Plant and its associated operation and maintenance expense and depreciation expense are Nevada jurisdictional.

10. Net General Plant and depreciation expense are allocated jurisdictionally on a ratio based on functionalize labor expense.

11. Net Intangible Plant and depreciation expense are allocated jurisdictionally on a ratio based on functionalized labor expense.

12. Other additions and deductions to rate base are allocated based on the items that give rise to them. For example, Materials and Supplies-Fuel is allocated on energy, as is Fuel Expense.

13. Customer Accounts Expense and Customer Service and Information Expense are assigned to the Nevada jurisdiction.

14. Administrative and General Expenses are allocated to jurisdictions using secondary allocation ratios based on Plant and/or Expenses. Regulatory Commission Expense and Resource Planning Expenses are directly assigned.

15. Allocation of Taxes other than Income Taxes, Deferred Income Taxes, Investment Tax Credits, and Schedule M Tax Adjustments are based on the item which gives rise to the tax or tax adjustment.

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, MATTHEW VALENTIC, 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: February 14, 2025

Matthew Valentic

BONNIE HUGHEY

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

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 25-02___
2025 General Rate Case

Prepared Direct Testimony of

Bonnie Hughey

Revenue Requirement

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

A. My name is Bonnie Hughey. My current position is Revenue and Regulatory Accounting Manager for Nevada Power d/b/a NV Energy ("Nevada Power" or the "Company") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra," and together with Nevada Power, the "Companies"). My business address is 6100 Neil Road in Reno, Nevada. I am filing testimony on behalf of Nevada Power.

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

A. I have been employed by the Companies for more than seven years. My regulatory duties have included the preparation of Statement J for both Nevada Power and Sierra, Exhibit G in support of the quarterly Deferred Energy Accounting Adjustment ("DEAA") filings, and other projects. I graduated from Lawrence Technological University with a bachelor's degree in business administration and later obtained a master's degree in information resource management from Central Michigan University. **Exhibit Hughey-Direct-1** contains additional information regarding my qualifications.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS REVENUE AND REGULATORY ACCOUNTING MANAGER.

A. As Revenue and Regulatory Accounting Manager, my responsibilities include the accounting and reporting of revenue for the Company, effective rate checks, the preparation and review of Statement J for this case and Exhibit G filed in other cases. In addition, I direct Company personnel in the preparation of regulatory statements, adjustments, and financial analysis.

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

A. Yes, I testified in Sierra's 2019 general rate case, Docket No. 19-06002.

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

A. The purpose of my testimony is to sponsor the following Schedules and Statements:

- Statement J – Total Recorded, Present Rate & Proposed Rate Revenues for the Test Period Ended September 30, 2024.
    - Schedule J-1 – Present & Proposed Rate Revenue: BTER & BTGR for the Test Period Ended September 30, 2024.
    - Schedule J-2 – Present & Proposed Rate Revenue: BTGR for the Test Period Ended September 30, 2024.
    - Schedule J-3 – Present Rate Revenue by Rate Schedule for the Test Period Ended September 30, 2024.
    - Schedule J-4 – Proposed Rate Revenue by Rate Schedule for the Test Period Ended September 30, 2024.
    - Schedule J-5 – Recorded Revenue by Rate Schedule for the Test Period Ended September 30, 2024.

  - Schedule J-6 – Operating Revenues, Sales and Customers for the Test Period Ended September 30, 2024.
  - Schedule J-7 – Annualized kWh with Weather Normalization Contribution for the Test Period Ended September 30, 2024.
  - Schedule J-8 – Present Rate Revenue: Impact of Weather Normalization for the Test Period Ended September 30, 2024.
  - Schedule J-9 – Summary of Recorded and Annualized Sales and Bills for the Test Period Ended September 30, 2024.
  - Schedule J-10 – Typical Bill Calculation.
- Statement J ECIC - Total Recorded, Present Rate & Proposed Rate Revenues for the Test Period Ended September 30, 2024.
  - Schedule J-1 through J-10 as listed above for Statement J.
- Statement J Daily Demand Pricing - Total Recorded, Present Rate & Proposed Rate Revenues for the Test Period Ended September 30, 2024.
  - Schedule J-1 through J-10 as listed above for Statement J.
- Statement J ECIC Daily Demand Pricing - Total Recorded, Present Rate & Proposed Rate Revenues for the Test Period Ended September 30, 2024.
  - Schedule J-1 through J-10 as listed above for Statement J.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibits:

Exhibit Hughey-Direct-1 Statement of Qualifications

7. Q. PLEASE DESCRIBE STATEMENT J.

A. Statement J and the related schedules present the change in the revenue requirement for each individual rate class. It provides a comparison of recorded revenues,

revenues at present rates and revenues at proposed rates. Present and proposed rate revenues are developed by applying the appropriate rates to annualized and weather normalized billing determinants for the Test Period ending September 30, 2024, to each customer class. The present rates used in preparing Statement J are the rates in effect on January 1, 2025. The development of the proposed rates based on the results of Statement J is discussed in the pre-filed direct testimony of Nevada Power witness, Samantha Prest.

Statement J also addresses the level and treatment of "other" Nevada jurisdictional revenues that I address below. The present rate revenue from these calculations is the starting point for the revenue requirement calculations. Finally, Statement J provides a separate verification that the proposed rates calculated in Statement O generate the requested revenue requirement.

8. Q. PLEASE DESCRIBE THE DIFFERENCES BETWEEN THE FOUR VERSIONS OF STATEMENT J.

A. Four versions of Statement J were filed, Statement J per the Nevada Revised Statutes ("NRS"). Statement J with ECIC changes per NRS, Statement J with Daily Demand Pricing for Residential customers per NRS, and Statement J with Daily Demand Pricing for Residential customers and ECIC changes per NRS.

9. Q. PLEASE DESCRIBE THE KEY RESULTS OF STATEMENT J.

A. Statement J per NRS shows that the impact of the proposed rates on all residential customers is a 9.71 percent increase over present rates. For non-residential customers, the increase is 5.49 percent and for distribution only service ("DOS") customers an increase of 51.70 percent.

Statement J with ECIC changes per NRS shows that the impact of the proposed rates on all residential customers is a 10.76 percent increase over present rates. For non-residential customers, the increase is 6.13 percent and for DOS customers an increase of 51.01 percent.

Statement J with daily demand pricing for residential customers per NRS shows that the impact of the proposed rates on all residential customers is a 9.78 percent increase over present rates. For non-residential customers, the increase is 5.41 percent and for distribution only service ("DOS") customers an increase of 51.21 percent.

Statement J with daily demand pricing for residential customers and ECIC changes per NRS is a 10.84 percent increase over present rates. For non-residential customers, the increase is 6.05 percent and for distribution only service ("DOS") customers an increase of 50.56 percent.

10. Q. WERE WEATHER-NORMALIZED SALES USED TO PRODUCE STATEMENT J?

A. Yes. Weather normalization of historic consumption and revenue data is an accepted practice in Nevada. The weather normalization methodology used in this case is discussed by Tim Pollard in his direct testimony.

11. Q. WHAT IS THE IMPACT OF WEATHER NORMALIZATION ON PRESENT RATE REVENUE?

A. Weather normalization decreased present rate Base Tariff General Rate ("BTGR") by $30.0 million, Base Tariff Energy Rate ("BTER") by $31.3 million and reduced

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the Deferred Energy Accounting Adjustment ("DEAA") and all other components by $5.5 million, netting to a combined total decrease of $66.8 million.

12. Q. PLEASE DESCRIBE THE CHANGES TO THE PRESENTATION OF STATEMENT J.

A. Statement J has been updated to reduce duplicate information and the number of filed workpapers. In previous filings, revenue for various programs including Renewable Energy Program ("REPR"), Energy Efficiency ("EE"), Natural Disaster Protection Plan ("NDPP"), Expanded Solar Project Costs ("ESPC"), and Expanded Solar Discount Recovery ("ESDR") were presented on separate schedules. The revenues for these programs have been consolidated and included in the revised Schedules J-3 and J-4.

13. Q. PLEASE BRIEFLY DESCRIBE SCHEDULES J-1 THROUGH J-10.

A. Schedule J-1 shows present and proposed BTGR and BTER revenues.

Schedule J-2 compares present and proposed BTGR revenue for only the BTGR component calculated from the annualized billing determinants shown in column (b). In addition to BTGR per kilowatt-hour ("kWh"), BTGR revenue includes basic service, demand, facility and power factor charges.

Schedule J-3 shows the annualized present rate revenues by rate schedule for the test period ending September 30, 2024. The revenues are separated into BTGR, BTER, DEAA, REPR/EE/NDPP and other revenue categories.

Schedule J-4 shows the annualized proposed rate revenues by rate schedule for the test period ending September 30, 2024. The revenues are separated into BTGR, BTER, DEAA, REPR/EE/NDPP and other revenue categories.

Schedule J-5 shows the recorded revenues by rate schedule for the test period ending September 30, 2024. The revenues are separated into BTGR, BTER, DEAA, REPR/EE/NDPP and other revenue categories.

Schedule J-6 shows recorded customers, sales and revenues by month for the test period. Included in this schedule are adjustments for unbilled sales and other special items that occurred during the test period. Other Revenues – Nevada are also shown along with revenue credits and adjustments from Statement N, Nevada jurisdiction. The revenues from this table appear in Statement H and Statement N, Nevada jurisdiction as recorded revenues.

Schedule J-7 shows changes in recorded kWh due to adjustments, annualizations and weather normalization. Annualization increased test period volumetric consumption by 584,933,258 kWh and weather normalization decreased test period volumetric consumption by 621,109,149 kWh for a net decrease to test period volumetric consumption of 36,175,891 kWh or .15 percent.

Schedule J-8 shows the impact on total revenue of non-weather adjustments and annualizations, as well as the incremental impact of weather normalization.

Schedule J-9 summarizes the recorded and annualized sales and bills for the test period for each rate classification. The table portrays the effects of annualization and weather normalization with respect to recorded sales. As shown in the table, annualized sales for the test period total 24,412,779 megawatt-hours ("MWh"), a decrease of .15 percent over recorded sales of 36,176 MWh. Average annualized bills, excluding Street and Private Area Lighting services, total 12,556,829, an increase of 1.33 percent during the test period total of 12,391,589 bills.

Schedule J-10 shows the typical bill calculation for residential single and multi-family rates using the updated average usage.

14. Q. PLEASE DESCRIBE THE PRIMARY STEPS INVOLVED IN DEVELOPING THE ANNUALIZED BILLING DETERMINANTS.

A. For all classes other than Street and Private Area Lighting, annualized billing determinants are developed in four steps:

1. Recorded billing determinants are summarized by existing customer classes. These billing determinants are comprised of the number of customers, separate meters, kWh sales, KW demand, facility demand, and billed kilovolt ampere-reactive hours (kVARh), which pertain to power factor charges. For classes with time of use ("TOU") billing, the kWh and kW determinants are also detailed by TOU period. Some classes also have contract demand determinants, and customer-specific facility charges.

2. The recorded billing determinants are adjusted, as necessary. Reasons for adjustments to recorded amounts include:

a) Moving usage reflected in the recorded data into the correct month or seasonal period; and

b) Correcting recorded entries that are the result of manual input errors, misclassification of customers in the Company's customer information system, or bill corrections made after the recorded entries. Also, any special adjustments or changes, usually for larger customers, are individually reviewed to ensure the most representative monthly sales level.

3. The resulting adjusted monthly kWh sales by class are then weather normalized, based upon the monthly weather-related adjustments to recorded sales estimated as described above. Only kWh billing determinants are weather adjusted. The kWh sales for certain classes such as street lighting, private area lighting, standby energy use, water pumping, and certain distribution-only schedules are not weather adjusted because, as discussed above, their loads are insensitive to weather.

4. The adjusted determinants (and in the case of kWh sales, the adjusted and weather normalized billing determinants) are then annualized. For example, kWh sales for each class other than street and private area lighting are annualized by using the following methodology:

a) Average kWh sales per customer is calculated for each month during the test period and by TOU period as applicable;

b) Monthly average kWh sales per month are multiplied by the customer count at the end of the test period; and,

c) Revised kWh for each month is then summed together to obtain the annual sales for the test period.

This same annualization methodology is also used for the kW demand (by TOU period as applicable), the non-customer specific facilities kW, and billed kVARh (power factor) determinants. As indicated, the annualized customer count is the number of customers in the class in the last month of the test period.

15. Q. ARE SPECIAL ADJUSTMENTS OR CHANGES IN METHODS USED TO ANNUALIZE SALES FOR LARGER CUSTOMERS?

A. Yes. Based on changes in usage during the test period, one customer in the Large Customer Market Price Energy ("LCMPE") tariff has been annualized with a projection for increased usage. Additionally, a customer who requested and qualified for the new tariff has been transferred from the LGS-3P to the OLGS-3P-HLF customer class.

16. Q. PLEASE EXPLAIN HOW LIGHTING REVENUES WERE ANNUALIZED.

A. The General Service ("GS") and Residential Service ("RS") Private Area Lights ("PAL") are flat-rate lighting services. The kWh sales to flat-rate lighting customers were derived in two steps:

i. For each class, the test period ending lamp (or bulb) count is multiplied by 12 to get the annualized number of lamps in the class and;

ii. The "rated" monthly kWh consumption for each class for the type of lamp is multiplied by the annualized number of lamps.

The sum of kWh sales calculated for each class is the total annualized kWh for the respective RS and GS PAL classes. The present rate BTER annualized revenues for the RS-PAL and GS-PAL classes were then computed as the product of the annualized kWh determinants and the present BTER. Similarly, present rate BTGR revenues were calculated for each lighting class as the product of the annualized number of lamps and the present BTGR monthly rate per lamp.

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B. Flat-rate Street Lighting Services were annualized in the same manner as the PAL lighting services.

17. Q. PLEASE DESCRIBE HOW YOU DEVELOPED THE "OTHER REVENUES" USED IN THE PRESENT AND PROPOSED RATE CALCULATIONS.

A. The following annualized adjustments have been made to "Other Revenues":

1. Account 450000, Forfeited Discounts, contains the revenue from late charges on overdue bills.

2. Account 454000, Rental Income, contains miscellaneous customer charges and has been annualized to include late billings.

3. Account 456001, Other Electric Rev-Adjust, contains miscellaneous billing adjustments.

4. Account 456002, Other Elec Misc. Rev, has been annualized to include ongoing amortizations and to include amortizations calculated on H-Cert-37.

5. Account 456003, Other Elec Rev-Amort & Special Charges, has been annualized to remove all test period revenue. All continuing amortizations will be included as revenue in appropriate distribution-only service classes.

6. Account 456006, Other Elec Rev-Rate Correction contains miscellaneous billing corrections.

7. Account 456025, Other Elec Rev-Pole Applic contains pole rental charges to customers and has been annualized to include late billings.

18. Q. IS THE COMPANY REQUESTING CONFIDENTIAL TREATMENT OF CERTAIN INFORMATION?

Nevada Power Company
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A. Yes. Confidential information is included in the executable versions of Statement J.

19. Q. PLEASE DESCRIBE THE CONFIDENTIAL MATERIAL.

A. Portions of Statement J contain information regarding the annual billing units, kWh usage, and other revenue for individual customers. To maintain the confidentiality of the customers' information, Nevada Power has designated this information as confidential pursuant to NRS § 703.196 and NAC § 703.5274.

20. Q. WILL STATEMENT J, STATEMENT J ECIC AND SUPPORTING SCHEDULES BE UPDATED FOR CERTIFICATION?

A. Yes. The Company will update the Statement J and supporting schedules at the end of the Certification Period for customer and sales information for the twelve-month period from March 1, 2024, through February 28, 2025.

21. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF THE COMMISSION'S REGULATORY OPERATIONS STAFF ("STAFF") OR THE NEVADA ATTORNEY GENERAL'S BUREAU OF CONSUMER PROTECTION ("BCP") TO PARTICIPATE IN THIS DOCKET?

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

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

A. Yes.

EXHIBIT HUGHEY-DIRECT-1

STATEMENT OF QUALIFICATIONS OF
Bonnie Hughey
Revenue and Regulatory Accounting Manager
NV Energy
6100 Neil Rd.
Reno, NV 89511

Bonnie Hughey has more than seven years of experience in various capacities at NV Energy, primarily focused on recording, analyzing, forecasting and reporting revenue. Ms. Hughey has prepared statements, reports, and data responses for regulators and interveners.

EMPLOYMENT HISTORY

2024 to Present — **NV Energy** — ***Revenue and Regulatory Accounting Manager***

Direct staff in the performance of various corporate and regulatory functions, including preparation of regulatory statements, adjustments, and analysis. Direct implementation of appropriate accounting procedures to comply with regulatory orders and developments. Oversee accounting and reporting for revenue and responsible for preparation of the internal component of tariff and ensuring proper accounting for rate changes.

2022 to 2024 — **NextEra Energy Resources** — ***Business Services Manager***

Direct staff in the execution of compliance-related activities, including adherence to internal policies, procedures, and controls to mitigate risks, safeguard assets, and ensure the accuracy of records. Oversee the internal controls testing process and the documentation of identified weaknesses in business processes. Lead efforts to recommend and implement corrective actions to address findings related to SOX, Corporate, or business division requirements.

2021 to 2022 — **NV Energy** — ***Business Systems and Data Analysis Manager***

Directed financial data management activities to support short-term and long-term forecasting and reporting requirements. Core responsibilities included extracting, transforming, and loading data from multiple sources into financial reporting platforms. Mapped and integrated key data sources within financial planning software to facilitate complex forecast calculations, management reporting, regulatory compliance, and other critical business initiatives.

2018 to 2022 — **NV Energy** — ***Revenue and Regulatory Specialist***

Conducted interim duties as Revenue and Regulatory Accounting Manager. Led process improvements for the forecast, revenue and regulatory teams.

2015 to 2018 — **NV Energy** — ***Senior Financial Analyst***

Oversaw company-wide consolidated reporting for both short-term and long-term planning. Key responsibilities included internal reporting, forecasting, data analysis, data management, ensuring integration and alignment with key financial business requirements.

2006 to 2015 — **LVI Global LLC** — ***Controller***

2001 to 2006 — **DTE Energy** — ***Senior Financial Analyst***

<u>EDUCATION</u>

Central Michigan University
MS in Information Resource Management – 1999

Lawrence Technological University
BS in Business Administration – 1993

Nevada Power Company
and Sierra Pacific Power Company
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AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, BONNIE HUGHEY, states that she 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 her knowledge and belief; and that if asked the questions appearing therein, her answers thereto would, under oath, be the same.

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

Date: February 14, 2025

Bonnie Hughey

ANTOINE TILMON

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

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 25-02___
2025 General Rate Case

Prepared Direct Testimony of

Antoine Tilmon

Revenue Requirement

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

A. My name is Antoine Tilmon. My current position is Vice President of Customer Operations for Nevada Power Company d/b/a NV Energy ("Nevada Power" or the "Company") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies"). My business address is 6226 W. Sahara Ave., Las Vegas, NV 89146. I am filing testimony on behalf of Nevada Power.

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

A. I have been employed by the Companies since April 7, 1997. I have more than 27 years of experience in the electric utility industry, including 27 years as a direct employee with the Companies. All my time employed with the Companies has been in the area of customer operations. In 2002, I participated in the implementation of the Companies' customer information system ("CIS") known as Banner. Over the last 20 years of this system, I have managed and maintained this system including developing new processes that improved and extended the life of Banner. Prior to becoming the Vice President, Customer Operations I served in many leadership roles, most recently as Director, Billing and Credit Operations, as set forth in my Statement of Qualifications, included as **Exhibit Tilmon-Direct 1**.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS VICE PRESIDENT OF CUSTOMER OPERATIONS.

A. As Vice President of Customer Operations my responsibilities include overseeing the following six customer operation departments:

1. Call Centers North and South- responsible for taking calls, chat, and email communication from the Companies' customers
2. Billing and Credit Operations – responsible for billing the Companies' customers and the credit and delinquency management of the billed customers.
3. Customer Programs and Services – responsible for managing customer programs and services, as well as tracking and managing the Companies' surveys to help improve customer service.
4. Customer Information Systems – responsible for the management and controls for Companies' CIS, known as Banner.
5. Workforce Optimization - responsible for workforce management, quality assurance, training and development.
6. Integrated Energy Services – responsible for delivery of the Companies' residential and commercial demand side management ("DSM") programs, transportation electrification programs, clean energy programs, and energy services customer engagement.

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

A. Yes. Most recently, I filed testimony with the Commission in Docket No. 23-06007, Nevada Power's 2023 General Rate Case ("GRC").

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

A. The purpose of my testimony is to discuss the Flex Pay Program ("Flex Pay"), as developed from Docket Nos. 14-10019 and 15-11003, and the Companies' request to recover the Flex Pay program implementation regulatory asset.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibits:

Exhibit Tilmon-Direct-1	Statement of Qualifications
Exhibit Tilmon-Direct-2	Flex Pay Cost Benefit Analysis
Exhibit Tilmon-Direct-3	Flex Pay Growth Analysis

7. Q. PLEASE EXPLAIN THE FLEX PAY PROGRAM.

A. Flex Pay is a voluntary prepaid energy program that empowers customers to better plan their energy usage based on their lifestyle, schedule, and budget. To be eligible for Flex Pay, residential electric and gas customers must have:

- a smart meter with remote connect/disconnect capabilities,
- internet access, and
- two verified communication channels for important account notifications via email, text, and voice messages.

Since Flex Pay is a prepaid service, a minimum $50 initial payment is required within five calendar days of enrollment to participate. The daily cost of customers' energy usage is deducted from this amount, including the daily fraction of monthly charges, such as customer fees and taxes. NV Energy engages in consistent communication with the customers – through their preferred communications methods – when their account balance approaches zero days remaining, giving them numerous notices and ample time to recharge their account as they see fit. They can make payments using any of NV Energy's payment methods, including more than 4,000 Authorized Payment Locations such as Smith's, Walmart and other Western Union pay sites. This allows customers to better manage both their energy usage and budget, as they can see in nearly "real-time" the cost of their home energy behavior. If a customer wants to participate in Flex pay, but they have a past due balance, they must pay at least 25 percent of the past-due balance within five days to establish a Flex Pay account (in addition to the $50 start-up cost). Customers who enroll in Flex pay are not required to maintain a deposit with the Companies. Customers with an existing deposit on their account who enroll in Flex pay will have their deposit applied to their Flex Pay account. The deposit is first used to pay any outstanding balances, and any remaining funds will be used as a credit on their Flex Pay account. The remaining 75 percent of any past due balance is paid down over time as funds are added to the account. The cost of customers' energy usage is deducted from this amount. When it is time to add funds to the account, customers may "reload" with any amount of their choice. After depositing funds into their account, their balance is reduced as they use energy, allowing customers to better manage both their energy usage and budget. Customers participating in Flex Pay are not eligible for payment arrangements. However, customers can pay off outstanding balances over time with 80 percent of each payment going towards a credit on their Flex Pay account and the remaining 20 percent towards any deferred balance until fully repaid. Once the customer's past-due balance reaches $0, all funds added to their Flex Pay account are used for future energy usage.

8. Q. PLEASE BRIEFLY DISCUSS THE HISTORY OF THE FLEX PAY PROGRAM.

A. In Nevada Power's 2014 GRC, Docket No. 14-05004, the Company requested to establish an optional prepayment program known as "Flex Pay." As part of the Stipulation in that Docket, Nevada Power withdrew its request and the signatories requested that an investigatory docket and subsequent rulemaking docket be opened if the program was approved, resulting in Docket No. 14-10019.[1] A proposed cost recovery methodology was presented in that docket and was accepted by the Commission in its Order, dated August 31, 2015 After initial Commission approval of the program, the Companies made the appropriate tariff filings with the Commission requesting to establish the Optional Flexible Prepayment ("OFP") tariff for electric and gas customers in both service territories.[2] The applications to establish these tariffs were approved in the Commission's Order dated May 31, 2016, in Docket Nos. 15-11003, 15-11004, and 15-11005.

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[1] Investigation and rulemaking to review and evaluate the merits of a prepayment program for electric services.

[2] Docket No. 15-11003, Application of Nevada Power Company d/b/a NV Energy filed under Advice Letter No. 459 to revise Tariff No. 1-B to establish an Optional Flexible Payment Program; Docket No. 15-11004, Application of Sierra Pacific Power Company d/b/a NV Energy filed under Advice Letter No. 577-E to revise Electric Tariff No. 1 to establish an Optional Flexible Payment Program; Docket No. 15-11005, Application of Sierra Pacific Power Company d/b/a NV Energy filed under Advice Letter No. 315-G to revise Gas Tariff No. 1 to establish an Optional Flexible Payment Program.

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9. Q. PLEASE DISCUSS THE COST RECOVERY METHODOLOGY THAT WAS APPROVED IN DOCKET NOS. 14-10019 AND 15-11003.

A. The Companies supported a cost recovery methodology that was built upon concepts advanced by the Regulatory Operations Staff ("Staff"). It was proposed that fixed costs of the program would be recorded as a regulatory asset in Federal Energy Regulatory Commission ("FERC") Account 182.3. If the program net benefits at the end of the five years exceeded program operating costs,[3] the Companies would be allowed to recover the fixed costs plus carrying charges recorded to the regulatory asset by including it in rate base in a GRC and amortizing it over a period consistent with the normal book life of the property. If the net benefits at the end of the five years did not exceed the program's operating costs, carry charges would not be sought for recovery, and the Companies would write-off the pro-rata proportion of the net benefits to the costs. This amount would also be included in a GRC, but not placed in rate base, and amortized over three years. The five-year period for meeting the program thresholds was to commence on January 1, 2017, or the first date the program was made available for customer enrollment. Company witness Jack McGinley testified in Docket Nos. 15-11003 and 15-11004 that the determination of the benefits ratio would be based upon the comparison of benefits to costs of the last 12 months' performance, which ultimately was May 2023 – April 2024.[4]

[3] Operating costs as defined by the Companies in their Supplemental Filing made on February 13, 2015, in Docket No. 14-10019.
[4] Docket Nos. 15-11003 and 15-11004, Direct Testimony of John McGinley, p. 4-5.

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10. Q. WHAT CRITERIA WAS TO BE CONSIDERED IN THE ANNUAL BENEFITS CALCULATION?

A. As proposed by the Companies, there were six measurable components specifically identified as being considered in the Annual Benefits calculation:[5]

- Reduction to paperless billing: Enrollment in Flex Pay requires paperless billing participation, thereby avoiding printing and mailing expenditures;
- Elimination of paper notices: Additional printing and mailing costs are avoided as notices and messaging are delivered through customers' preferred electric communication channels;
- Contact center reductions: Communications with participants are proactive and frequent, thus reducing the number of calls made by those customers to ask questions about account balances, terminations, past due balances and payment arrangements;
- Reduction in write-offs: Flex Pay prevents participating customers from building significant past due balances, reducing bad debt write-offs;
- Write-off recovery fees savings: The reduction in write-offs reduces the fees paid by the Companies, and subsequently their customers, for tracking and recovering bad debt made by the Companies and their collection agencies; and
- "Shop and Pay" transaction fee reduction: More frequent payments are expected, thus reducing the per transaction cost for all payments.

Ultimately, the Commission accepted these benefit calculations as proposed by the Companies with modifications made by Staff. In particular, Staff recommended that the estimate of the bad debt write-off reduction benefit per Flex Pay customer

[5] Docket Nos. 15-11003 and 15-11004, Direct Testimony of Anita Castledine, Ph.D., p. 22-24.

should be quantified as the difference between the current write-off rate for the non-Flex Pay Program group (non-Flex Pay Program account write-offs divided by number of non-Flex Pay Program customers) and the current write-off rate for the Flex Pay Program group (Flex Pay Program account write-offs divided by number of Flex Pay Program customers).[6] The total write-off benefits are the benefits per Flex Pay customer multiplied by the number of Flex Pay customers.

11. Q. DID THE COMPANY MEET THOSE CONDITIONS AS PRESCRIBED? IF NOT, PLEASE DISCUSS WHY THE COMPANY IS STILL SEEKING RECOVERY.

A. The Company achieved some of the conditions, but not all of them. However, as discussed below, the Company believes the costs were prudently incurred and still provide ample value to the customers that have utilized Flex Pay, as well as the Companies' non-participating customers. Thus, the Company is requesting full recovery of the program's costs, as presented in H-CERT-32, which I co-sponsor with Company witness, Jenny Naughton.

12. Q. SHOULD THE COMPANY ONLY LOOK TO THE PRESCRIBED BENEFITS CALCULATION.

A. No, in Docket Nos. 15-11003, 15-11004, and 15-11005, the Commission encouraged the Companies to propose other benefit calculation methodologies for bad debt write-offs.[7] This analysis of other benefit calculation methods is important, because it provides a more complete a holistic understanding of the program and the benefits it delivered under the program versus relying only on the

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[6] *Id*. at p. 11.
[7] Docket Nos. 15-11003, 15-11004, and 15-11005, *Order* dated May 31, 2016, at 54, ¶ 137.

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prescribed benefits calculation. This is especially important when rolling out a new program.

13. Q. DOES THE COMPANY FEEL THAT THE PRESCRIBED BENEFITS CALCULATION IS CORRECT?

A. No, the Company believes the bad debt write-off savings calculation component of the calculation contains incorrect assumptions. It includes costs incurred before customers enrolled in Flex Pay, rather than focusing on changes after enrollment. Tilmon-Direct-2" "Scenario 1" shows the inclusion of outstanding balances predating customers enrolling in the program. It is not appropriate to include outstanding or past due balances on customer accounts that were in place before they enrolled in the Flex Pay program, because it incorrectly inflates the past due amount at the time of bad debt write-off being attributed to the Flex Pay program. For example: if a customer enrolled in Flex Pay and had a past due balance currently on their account of $1,000 and over the course of being in the Flex Pay program paid down the past due balance by $700 (leaving just $300 in the prior past due account), that should be a net benefit to participating in the Flex Pay program, but under the currently model it reflects a $300 dollar past due balance attributed to the Flex Pay program.

To address this, the Company proposes a revised calculation, shown in "Scenario 2" that excludes pre-enrollment amounts and only considers amounts collected or increases after enrollment in Flex Pay. This is a more accurate and equitable calculation, because it evaluates customer behavior and benefits for the time customers were actually participating in the program. When evaluating impact while customers were actually participating in the program, versus including past

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due balances that were in place before the customer enrolled in Flex Pay, the benefits of the program exceed the operating cost by $674,451 dollars, thus supporting full cost recovery through rate base inclusion and amortization over the assets' typical lifespan.

14. Q. DID THE COMPANY MEET THE PARTICIPATION RATE AS WAS PROPOSED AND PROJECTED BY THE COMPANIES IN THE ORIGINAL DOCKETS? IF NOT, PLEASE EXPLAIN WHY.

A. No. During the pre-COVID period, NV Energy experienced strong growth in customer participation in the Flex Pay program. The program grew from 80 customers in January of 2019 to 10,802 by December of 2019. The program showed continued growth in 2020, increasing enrollment by 10 percent, however that growth was hampered by COVID-19 and all the uncertainty during that time frame. Exhibit Tilmon Direct – 3 shows the program growth. The challenges of engaging customers and promoting the program during the pandemic slowed the momentum that had previously driven participation growth, and many customers were taking advantage of Company and government sponsored programs to assist with bills during this time, which along with the moratorium of disconnects likely stalled participation. Despite these setbacks, the Flex Pay program has demonstrated resilience, achieving an average growth rate of 10.47 percent through 2024, as shown in Exhibit Tilmon Direct - 3 Flex Pay Growth Analysis. Moving forward, the Company remains committed to expanding the program through enhanced marketing and customer education initiatives. Additionally, the proposed revised calculations reveal cost benefits. This will enable the Company to expand and grow the Flex pay program organically, like other payment options the Company offers.

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15. **Q. DID THE FLEX PAY PROGRAM DELIVER COST BENEFITS TO CUSTOMERS IN EXCESS OF PROGRAM COSTS**

A. Yes. The benefits of the program, using the proposed past due calculation method identified in Tilmon 2 results in a benefit totaling $686,448 versus a cost of $11,997 which is a net benefit of $674,451.

16. Q. DOES THIS PROGRAM PROVIDE ADDITIONAL BENEFITS FOR CUSTOMERS? IF SO, PLEASE EXPLAIN WHY.

A. Yes. The Flex Pay program provides several benefits for customers, particularly those looking for greater control over their energy usage and costs. Notably, the key benefits for participation are:

- Enhanced budget control with Pay-As-You-Go flexibility (customers can pay for electricity in smaller, more manageable increments instead of receiving a large bill at the end of the month).
- Avoiding late fees (because customers pay upfront, there is no risk of late payment fees or overdue balances).
- Real-time awareness of energy usage, immediate feedback (Flex Pay provides tools to enrollees that allow them to monitor their energy usage and costs as quickly as the next day, demonstrating how far their dollar goes before their account needs to be replenished, thereby leading to more conscious energy habits).
- Usage alerts (customers are notified when their balance is low, helping them manage their consumption proactively).
- No surprise bills (eliminates the uncertainty of monthly bills as customers only use what they have already paid for, avoiding unexpected charges).

- No deposit requirement or credit check for new customers (increasing access to safe and reliable service for lower-income customers).

Additionally, Flex Pay benefits non-participating customers by reducing uncollectible expense, which is shared by all customers.

17. **Q.** **SHOULD THE FLEX PAY PROGRAM BE CONTINUED?**

A. Yes, the Flex Pay program should be continued and remain an option for those that want to utilize it. Customers have expressed the need for more flexibility and more options when it comes to paying their energy bills, and the Company does not want to eliminate any programs that help customers pay their bills. Utilities offering prepay across the country report energy savings ranging from 5 percent to 14 percent due to prepay, according to E Source.[8] Salt River Project, North America's oldest and largest prepay program, reports conservation rates of 12% for its roughly 150,000 enrolled customers, or 15 percent of its residential customer base. SRP also reports that these customers accounted for 26 percent of the company's annual aggregate energy savings, and 55 percent of its demand reduction in 2024.[9] Additional benefits accrue to all customers as the Flex Pay program reduces write-offs and bad debt and reduces the Companies' cost to meet peak demand.

18. **Q.** **WHAT MEASURES WILL THE COMPANY TAKE TO PROMOTE FLEX PAY AND CREATE FURTHER BENEFITS?**

A. Customers are enrolling in the program, but many are dropping out within the first 60 days. Data shows that Flex Pay customers stay enrolled 61 percent longer once

[8] "Using behavioral strategies to improve prepay and demand-side management," E Source, July 2023, https://www.esource.com/system/files/esource-behavior_exchange_july_2023.pdf, slide 21.
[9] SRP Annual Report 2023, https://www.srpnet.com/assets/srpnet/pdf/grid-water-management/sustainability-environment/2024-ENG-Customer-Programs-Report.pdf , p. 11.

the customer makes it past the first 60 days. The data shows that the Company's churn of 40 percent occurs within the first 60 days, which is much higher than other utilities. Therefore, the Company will use several tactics to reduce the churn, effectively promote Flex Pay, and maximize its benefits for customers. The Company proposes to:

- Offer tutorials, seminars, or workshops to educate customers about how Flex Pay works, emphasizing its advantages like budget control, no deposits, and real-time monitoring;
- Leverage social media, email newsletters and advertisements to highlight success stories and testimonials from current Flex Pay users;
- Focus on specific demographics (e.g., renters, students, or budget-conscious households) who benefit the most from prepaid programs;
- Ensure the app or online portal is intuitive, providing customers with real-time energy usage, low-balance alerts, and easy payment options;
- Use chatbots or live support for immediate responses to balance inquiries or payment needs;
- Demonstrate Flex Pay's relation to sustainability by showcasing how it encourages customers to reduce energy waste, benefiting both their wallets and the environment;
- Use surveys and focus groups to understand what features customers value most and what barriers they face when using Flex Pay;

By implementing these measures, the Company can drive adoption of Flex Pay and ensure it delivers significant benefits to customers, creating a positive loop of satisfaction and trust.

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

A. Yes.

EXHIBIT TILMON-DIRECT-1

ANTOINE M. TILMON
VICE PRESIDENT, CUSTOMER OPERATIONS
NV Energy, Inc.
6226 West Sahara Avenue
Las Vegas, NV 89146
(702) 402-5673

Antoine has more than 27 years of experience in the electrical utility industry, including 27 years of direct employment with NV Energy. In 2002 Antoine participated in the implementation NV Energy's customer information system known as Banner. Over the last 20 years of this system, he has managed as an end user and has been responsible for controls and have designed new processes that improved the functionality and extended the life of Banner. Prior to becoming the Vice President, Customer Operations in January 2021 he served in many leadership roles starting in January of 2000 with the last being Director, Billing and Credit Operations.

Employment History

NV Energy, Las Vegas, NV — Dec 2014 - 2020
Director Billing & Credit South Ops

- Directed daily operation of the development of Billing and Credit personnel to ensure timely and accurate billing and collection of customers.
- Directed MV90, Billing Expert and the Meter Data Management System
- Ensure compliance with business controls and regulations related to Billing and Credit compliance to PUCN Tariffs, Nevada Administrative Codes, and Sox compliance
- Ensure compliance with business controls and regulations related to Billing and Credit compliance to PUCN Tariffs, Nevada Administrative Codes, and Sox compliance.
- Developed and monitored performance against the annual division budget.

NV Energy, Las Vegas, NV — Dec 2006 - 2014
Supervisor Billing & Credit South Ops

- Oversee daily operation of the development of Billing and Credit personnel to ensure timely and accurate billing and collection of customers.
- Oversee MV90, Billing Expert and the Meter Data Management System
- Ensure compliance with business controls and regulations related to Billing and Credit compliance to PUCN Tariffs, Nevada Administrative Codes, and Sox compliance
- Supervises and participates in developing, implementing and evaluating plans, work processes, systems and procedures to achieve annual goals, objectives and work standards of MPAT and Bargaining Unit Employees.

Nevada Power Company, Las Vegas, NV Aug 2003 - Dec 2006
Team Leader Credit NPC

- Ensure compliance with business controls and regulations related to Credit compliance to PUCN Tariffs, Nevada Administrative Codes, and Sox compliance.
- Monitor Credit Performance metrics and implemented appropriate measures to ensure frontline employees achieve performance targets.
- Monitors collections of utility billings; takes or recommends action to maximize collections; reviews periodic reports of delinquent accounts; assists staff in resolving the more difficult and complex collections and credit cases; recommends and/or takes action on delinquent accounts.

Nevada Power Company, Las Vegas, NV Feb 2000 – Aug 2003
Team Leader Telephone Service Operations NPC

- Responsible for supervising teams of customer service representatives engaged in providing a variety of customer account, collections and credit services to Nevada Power Company's diverse customer base.
- Plans, organizes, controls, integrates and evaluates the work of assigned staff; with staff, develops, implements and monitors work plans to achieve goals and objectives
- Supervises and participates in developing, implementing and evaluating plans, work processes, systems and procedures to achieve annual goals, objectives and work standards.

Nevada Power Company, Las Vegas, NV Oct 1997 to Feb 2000
Energy Consultant, II

Consistently earn highest rating in customer service for quality surveys

Coordinated and responded to complex customer high bill complaints, resulting in increased customer satisfaction.

Promoted corporate-wide participation and support of residential conservation programs

Provided training to customers effectively helping them conserve energy.

Provided energy efficiency and conservation solutions that met residential customer needs.

Education

A.A.S. degree in Applied Sciences Jan 1990
Pikes Peak Community College, Colorado Springs CO

Continuing Education

NV Energy
Customer Relations, Diversity Training, Public Utilities Report Guide, 7 Habits of Highly Effective People, Project Management, Mutual Gains, Process Redesign, Crystal Reports Info Desktop & Report Writer, Instructional System Design, Leadership Training 'Your Role As Coach', MARC Leadership Training, Systems Development Life Cycle, Power Principles Basic Power Plant Operations.

COMPUTER SKILLS

MS Office (Word, Excel, PowerPoint), Microsoft Project, Flowcharting 3, VISIO, Crystal Reports, People Soft.

EXHIBIT TILMON-DIRECT-2

FlexPay Recovery Analysis - Nevada Power Company

Scenario 1		**Per Order in Docket 15-11003**	**Benefit Ratio**
Net Benefit/(Cost)	$	(1,176,898)	
Operating Costs without Additional Journaled Labor[1]		(11,997)	0.00%
Overall Benefit/(Cost)	$	(1,188,895)	

Scenario 2		**Alternate Method (Reduction in Write-Offs)**	**Benefit Ratio**
Net Benefit/(Cost)	$	686,448	
Operating Costs without Additional Journaled Labor[1]		(11,997)	100.00%
Overall Benefit/(Cost)	$	674,451	

Notes

1. Net amount after participation revenue ($2.50 fee) factored in

FlexPay Cost/Benefit Analysis Calculation	Amount
Paperless Billing	
Inputs	
Total # of customers enrolled in FlexPay who were NOT enrolled in Paperless Billing prior to enrollment in FlexPay	26,212
The residential Cost of Bill Creation	$ 0.07
The corporate metered postage rate used for physical mailings	$ 0.64
Calculated Benefit	$ 18,611
Elimination of Paper Notices	
Total Customers Enrolled in the FlexPay program	24,920
Total eligible customers NOT enrolled in FlexPay program	601,741
Total 10 day and 48 hour notices sent out for FlexPay customers during the calculation month	919
Total 10 day and 48 hours notices sent out of Non-FlexPay customers during the calculation month	788,634
Total generation cost for 10 day and 48 hour notices including printing and postage	$ 0.71
Calculated Benefit	$ 22,536
Contact Center Call Reductions	
Total customers enrolled in the FlexPay program	24,920
Total eligible customers NOT enrolled in FlexPay program	601,741
Total contacts(represents all contacts related to payment arrangments and disconnect for non-payment) for FlexPay customers during the calculation	9,138
Total contacts(represents all contacts related to payment arrangments and disconnect for non-payment) for Non-FlexPay customers during the calculation	152,834
The average cost per contact center contact	$ 8.13
Calculated Benefit	$ (22,834)
Reduction in Write-Offs (per Order)	
Total customers enrolled in the FlexPay program	24,920
Total eligible customer NOT enrolled in the FlexPay program	601,741
Total past due write off amounts for FlexPay customers during the calculation month (includes amounts that were bro	2,025,463
Total past due write off amounts for Non-FlexPay customer during the calculation month	20,484,294
Calculated Benefit	$ (1,177,143)
Write-Off Recovery Fees Savings	
Total customers enrolled in the FlexPay program	24,920
Total eligible customers NOT enrolled in the FlexPay program	601,741
Total write off recovery fee amount paid for FlexPay customers during the calculation month	40,548
Total write off amount recovery fee amount for Non-FlexPay customers during the calculation month	542,852
Calculated Benefit	$ (18,066)

Shop and Pay Transaction Fee Reduction	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24
The monthly total transaction count from Shop & Pay	33,677	34,378	35,568	37,090	34,152	33,313	31,914	31,066	30,853	30,276	31,921	30,296
The number of monthly transactions required to reach the lowest price per transaction fee	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000
The lowest cost per transaction tier structure of the Shop & Pay contract with NV Energy	$ 0.62	$ 0.62	$ 0.62	$ 0.62	$ 0.62	$ 0.62	$ 0.62	$ 0.62	$ 0.62	$ 0.62	$ 0.62	$ 0.62
The highest cost per transaction tier strucutre of the Shop & Pay contract with NV Energy	$ 0.66	$ 0.66	$ 0.66	$ 0.66	$ 0.66	$ 0.66	$ 0.66	$ 0.66	$ 0.66	$ 0.66	$ 0.66	$ 0.66
Calculated Benefit												

Total	$ (1,176,898)

FlexPay Cost/Benefit Analysis Calculation	Amount
Paperless Billing	
Inputs	
Total # of customers enrolled in FlexPay who were NOT enrolled in Paperless Billing prior to enrollment in FlexPay	26,212
The residential Cost of Bill Creation	$ 0.07
The corporate metered postage rate used for physical mailings	$ 0.64
Calculated Benefit	$ 18,611
Elimination of Paper Notices	
Total Customers Enrolled in the FlexPay program	24,920
Total eligible customers NOT enrolled in FlexPay program	601,741
Total 10 day and 48 hour notices sent out for FlexPay customers during the calculation month	919
Total 10 day and 48 hours notices sent out of Non-FlexPay customers during the calculation month	788,634
Total generation cost for 10 day and 48 hour notices including printing and postage	$ 0.71
Calculated Benefit	$ 22,536
Contact Center Call Reductions	
Total customers enrolled in the FlexPay program	24,920
Total eligible customers NOT enrolled in FlexPay program	601,741
Total contacts(represents all contacts related to payment arrangments and disconnect for non-payment) for FlexPay customers during the calculation	9,138
Total contacts(represents all contacts related to payment arrangments and disconnect for non-payment) for Non-FlexPay customers during the calculation	152,834
The average cost per contact center contact	$ 8.13
Calculated Benefit	$ (22,834)
Reduction in Write-Offs (Alternative Approach)	
Total customers enrolled in the FlexPay program	24,920
Total eligible customer NOT enrolled in the FlexPay program	601,741
Total past due write off amounts for FlexPay customers during the calculation month (only amount accumulated while	162,117
Total past due write off amounts for Non-FlexPay customer during the calculation month	20,484,294
Calculated Benefit	$ 686,202
Write-Off Recovery Fees Savings	
Total customers enrolled in the FlexPay program	24,920
Total eligible customers NOT enrolled in the FlexPay program	601,741
Total write off recovery fee amount paid for FlexPay customers during the calculation month	40,548
Total write off amount recovery fee amount for Non-FlexPay customers during the calculation month	542,852
Calculated Benefit	$ (18,066)

Shop and Pay Transaction Fee Reduction	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24
The monthly total transaction count from Shop & Pay	33,677	34,378	35,568	37,090	34,152	33,313	31,914	31,066	30,853	30,276	31,921	30,296
The number of monthly transactions required to reach the lowest price per transaction fee	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000
The lowest cost per transaction tier structure of the Shop & Pay contract with NV Energy	$ 0.62	$ 0.62	$ 0.62	$ 0.62	$ 0.62	$ 0.62	$ 0.62	$ 0.62	$ 0.62	$ 0.62	$ 0.62	$ 0.62
The highest cost per transaction tier strucutre of the Shop & Pay contract with NV Energy	$ 0.66	$ 0.66	$ 0.66	$ 0.66	$ 0.66	$ 0.66	$ 0.66	$ 0.66	$ 0.66	$ 0.66	$ 0.66	$ 0.66
Calculated Benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Total	$ 686,448

Project ID	0010007823
Period	(Multiple Items)

Sum of Actual Amount	Column Labels														
	2023								2024				Grand Total		
Row Labels	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**1**	**2**	**3**	**4**			
Flexpay OMAG South	**90,274**	**15,632**	**32,688**	**96,076**	**31,178**	**33,374**	**107,581**	**96,110**	**1,323**	**33,954**	**65,472**	**92,387**	**696,049**		
Labor	**1,276**	**1,000**	**959**	**1,483**	**815**	**881**	**592**	**520**	**945**	**1,024**	**640**	**589**	**10,725**		
Labor incl OHs (Programs and Svcs)	1,092	915	869	1,483	815	881	592	520	945	1,024	640	589	10,366	Directly Charged	
Labor incl OHs (Billing)	184	85	90										359	Directly Charged	
Non-Labor	**88,998**	**14,632**	**31,729**	**94,593**	**30,363**	**32,493**	**106,988**	**95,590**	**378**	**32,930**	**64,832**	**91,798**	**685,324**		
Monthly License Fees	39,860	14,632	31,729	30,141	30,363	32,493	34,928	44,931	378	32,930	64,832	34,778	391,994	Directly Charged	
Non Labor_Customer Payments	10,534			22,194			25,753	15,348				14,957	88,786	Charged through Manual Journal	
Non Labor_Kubra	38,605			42,258			46,307	35,311				42,064	204,544	Charged through Manual Journal	
Grand Total	**90,274**	**15,632**	**32,688**	**96,076**	**31,178**	**33,374**	**107,581**	**96,110**	**1,323**	**33,954**	**65,472**	**92,387**	**696,049**		
Manual Journals	49,138	-	-	64,452	-	-	72,060	50,659	-	-	-	57,020	293,330		
Manual Journals Referring to:	**Q1-2023**			**Q2-2023**			**Q3-2023**	**Q4-2023**				**Q1-2024**			
Adjustment to subtract Q1 2023 Journal	(49,138)	-	-	-	-	-	-	-	-	-	-	-	(49,138)		
Adjusted Total Costs	**41,136**	**15,632**	**32,688**	**96,076**	**31,178**	**33,374**	**107,581**	**96,110**	**1,323**	**33,954**	**65,472**	**92,387**	**646,911**		
Revenue Offset at 2.50 per Participant	**(51,732)**	**(49,645)**	**(49,574)**	**(45,643)**	**(46,491)**	**(49,043)**	**(52,072)**	**(54,724)**	**(57,061)**	**(58,290)**	**(59,742)**	**(60,897)**	**(634,914)**	Source: Matthew Valentic	98.1%
Net of Costs and Revenue	**(10,596)**	**(34,013)**	**(16,886)**	**50,433**	**(15,313)**	**(15,669)**	**55,509**	**41,385**	**(55,737)**	**(24,337)**	**5,730**	**31,490**	**11,997**		
	20,693	19,858	19,830	18,257	18,597	19,617	20,829	21,890	22,824	23,316	23,897	24,359			
	62,078	59,573	59,489	54,771	55,790	58,851	62,486	65,669	68,473	69,948	71,691	73,077	761,896		

EXHIBIT TILMON-DIRECT-3

FlexPay Month End								
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
January		9	80	11,589	12,147	21,540	25,613	29,113
February		8	109	12,350	12,584	22,172	25,810	29,906
March		7	132	12,354	13,526	22,646	26,108	30,553
April		7	162	12,712	13,929	23,058	24,737	30,886
May		8	197	12,272	14,257	22,774	24,178	30,765
June		13	256	11,508	14,274	21,863	24,179	29,324
July		14	255	10,876	14,829	21,369	23,325	27,274
August		17	543	10,327	15,784	21,588	23,815	25,824
September		18	4,789	10,507	17,117	22,447	25,083	25,372
October		41	6,994	11,252	18,922	23,859	26,878	25,047
November	8	65	9,870	11,631	20,191	24,946	27,676	26,106
December	8	**81**	**10,802**	**11,886**	**20,840**	**25,537**	**28,402**	**27,732**
Percentage of Growth		912.50%	13235.80%	10.04%	75.33%	22.54%	11.22%	-2.36%
Average Percentage of Growth				**Average Growth 2022 -2024**			**10.47%**	

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, ANTOINE TILMON, 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: February 14, 2025

Antoine Tilmon

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

MICHAEL HOLLAND

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

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 25-___
2025 General Rate Case

Prepared Direct Testimony of

Michael Holland

Revenue Requirement

I. INTRODUCTION

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

A. My name is Michael Holland. My current position is Vice President, Resource Optimization for Nevada Power Company d/b/a NV Energy ("Nevada Power" or the "Company") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies"). My business address is 6226 West Sahara Avenue, Las Vegas, Nevada. I am filing testimony on behalf of Nevada Power.

2. Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A. My experience includes more than 16 years in the energy sector with positions in several areas, including power and natural gas trading and the oversite of energy trading activities in multiple markets. I have been in various leadership roles overseeing activities related to energy trading, retail natural gas and electric supply, origination and market operations. More details regarding my background and experience are provided in **Exhibit Holland 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 Department. Resource Optimization is responsible for a number of activities, including, but not limited to, all power and natural gas trading activities, coal procurement, participation in the Western Energy Imbalance Market ("EIM"), renewable resource origination, contract management, and wholesale market design efforts.

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

A. No.

5. Q. WHAT IS THE PURPOSE OF YOUR PREPARED DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe the status of current day-ahead market initiatives and to identify the activities that contributed to the expenses recorded in the regulatory asset for these initiatives. Additionally, based on the results of the activities performed thus far, the Company is also requesting to establish a separate regulatory asset for the implementation of the Extended Day-Ahead Market ("EDAM") costs.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibits:

Exhibit Holland-Direct-1 Statement of Qualifications

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

II. <u>STATUS OF MARKET DEVELOPMENT AND EXISTING REGULATORY ASSET</u>

7. Q. WHAT IS THE STATUS OF DAY-AHEAD MARKET DEVELOPMENT?

A. Based on the success of the Western Energy Imbalance Market ("EIM"), the California Independent System Operator ("CAISO") initiated a stakeholder process in November 2021 to expand its market services by extending day-ahead market participation to EIM participants. Following a stakeholder process, on August 22, 2023, the CAISO submitted its Day-Ahead Market Enhancement and EDAM tariff amendment to the Federal Energy Regulatory Commission ("FERC"). In its December 20, 2023, order, FERC accepted in part, subject to condition, and rejected in part the tariff revisions.[1] The CAISO made the required compliance filing in Docket No. ER23-2686 on February 16, 2024. With respect to the transmission rate for EDAM, the part of the initial filing rejected by FERC without prejudice, the CAISO made a subsequent filing in Docket No. ER24-1746 that was accepted by FERC on April 30, 2024. In addition, PacifiCorp filed proposed modifications to its Open Access Transmission Tariff ("OATT") with FERC to implement EDAM in Docket No. ER25-573 on November 26, 2024. In addition, PacifiCorp filed proposed modifications to its Open Access Transmission Tariff to implement EDAM at FERC in Docket No. ER25-951 on January 16, 2025.

PacifiCorp, Portland General Electric ("PGE"), the Balancing Authority of Northern California ("BANC"), and the Los Angeles Department of Water and Power have EDAM Implementation Agreements with CAISO. In a letter dated March 21, 2024, Idaho Power stated it was "currently leaning towards

[1] *Cal. Indep. Sys. Operator Corp.*, 185 FERC ¶ 61,210.

EDAM."[2] Public Service Company of New Mexico and BHE Montana have also expressed an intent to participate in EDAM.[3] PacifiCorp and PGE anticipate going live in 2026. Given an approximately 18-month period for onboarding new participants, the earliest entry date for additional participants is expected to be Spring 2027. Several other entities, including Arizona G&T Cooperatives and Seattle City Light, are studying EDAM participation.

The Southwest Power Pool ("SPP") introduced its Markets+ initiative during a November 17, 2021, webinar.[4] Following a stakeholder process, SPP released "A Proposal for Southwest Power Pool's Westen Day-Ahead Market Services" on November 30, 2022.[5] The Companies and 23 other entities executed the Phase 1 Funding Agreement that supported SPP's costs in further developing the Markets+ design and incorporating it into a tariff to be filed at FERC.[6] The Phase 1 work was accomplished by 10 committees and work groups.[7] The Companies participated in each of these bodies. On March 29, 2024, in FERC Docket No. ER24-1658, SPP filed the Markets+ tariff with FERC. SPP initially requested FERC issue an order by July 31, 2024. On that day, however, FERC

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[2] *See* https://www.caiso.com/Documents/Idaho-Power-EDAM-Letter.pdf.
[3] *See* https://www.westerneim.com/Pages/ExtendedDayAheadMarket.aspx.
[4] See https://spp.org/documents/66073/11172021%20markets%20plus%20information%20session%20presentation.pdf.
[5] The proposal can be accessed at: https://www.spp.org/documents/69346/spp%20markets%20plus%20proposal.pdf.
[6] Thirty-one entities had voting rights in Phase 1. See https://spp.org/news-list/spp-s-development-of-marketsplus-underway-with-funding-and-participation-from-diverse-western-stakeholders/. Participants in Phase 1 included: American Clean Power Association; Arizona Electric Power Cooperative, Inc.; Arizona Public Service; Black Hills Colorado Electric, LLC; Black Hills Power, Inc.; Bonneville Power Administration; Chelan County Public Utility District; Cheyenne Light, Fuel and Power Company; Clean Energy Buyers Association; Grant County Public Utility District; Interwest Energy Alliance; Liberty Utilities (CalPeco Electric), LLC; Municipal Energy Agency of Nebraska; Northwest and Intermountain Power Producers Coalition; NV Energy, Inc.; Pattern Energy; Powerex Corp.; Public Generating Pool; Public Power Council; Puget Sound Energy; Renewable Northwest Project; Salt River Project; Snohomish County Public Utility District; Tacoma Power; The Energy Authority; Tri-State Generation and Transmission Association; Tucson Electric Power Company; Western Energy Freedom Action; Western Power Trading Forum; Western Resource Advocates; and Xcel Energy – Colorado.
[7] *See* https://www.spp.org/western-services-documents/?id=371697.

issued a Deficiency Letter. SPP provided the requested information on September 20, 2024. In an order issued January 16, 2025, FERC conditionally approved the SPP tariff subject to a compliance filing in 30 days. SPP continues to work with participants on development of protocols for the new market. On November 4, 2022, Powerex expressed its intent to join Markets+.[8] More recently, in November 2024, Arizona Public Service Company, Salt River Project, Tucson Electric Power and UniSource Electric indicated that they plan to join Markets+.[9] Bonneville Power Administration ("BPA") has also expressed its intent to issue a draft policy letter in March 2025 on whether to adopt the BPA staff recommendation to participate in Markets+.[10] The Companies expect that many of the other Phase 1 participants will continue to support the build-out of Markets+ in Phase 2.

8. Q. PLEASE DISCUSS THE COMPANIES' CURRENT DECISION-MAKING PROCESS REGARDING JOINING A MARKET.

A. The decision to join a day-ahead market is a significant event that will require quantitative and qualitative showings in a future filing. And while it is not impossible to exit a market, it is far better to get the decision correct the first time. It is for that reason the Companies have taken a methodical approach and have performed due diligence on both day-ahead market options. The Companies have been an active participant in the development of the two day-ahead market options in the West and have worked with other utilities on

[8] *See* https://powerex.com/sites/default/files/2022-11/Powerex%20Commits%20to%20Markets%2B.pdf.
[9] *See* https://www.aps.com/en/About/Our-Company/Newsroom/Articles/AZ_Utilities_Plan_to_Join_Markets_Plus_to_Strengthen_Grid_Reliability_and_Resilience.
[10] *See* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/20241231-response-to-or-wa-senators.pdf. The April 2024 Staff recommendation can be accessed at: https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/02-day-ahead-market-attachment-1-staff-recommendation.pdf.

several studies evaluating potential benefits associated with the different market designs and possible footprints. Based on a holistic view of these qualitative and quantitative factors, including but not limited to the governance changes resulting from the West-Wide Governance Pathway Initiative, the Companies expressed their intent to request authorization from the Commission to participate in EDAM.[11] As the second participant in the EIM, the Companies have experienced significant economic, reliability, and environmental benefits. Having developed a market that includes more than 80 percent of load in the Western Electricity Coordinating Council, the Companies would hope to preserve as much of that size and diversity as possible while expanding the scope of the organized market services. Critical to the Companies' decision is the expected EDAM footprint. The anticipated participation by CAISO, PacifiCorp, BANC, Los Angeles Department of Water and Power, PGE, Idaho Power and Public Service Company of New Mexico, provides a significant degree of interconnectivity and supports a diversity of resources. This is illustrated in Figure Holland-Direct-1.

[11] See Docket No. 24-05021, Narrative, p. 29.

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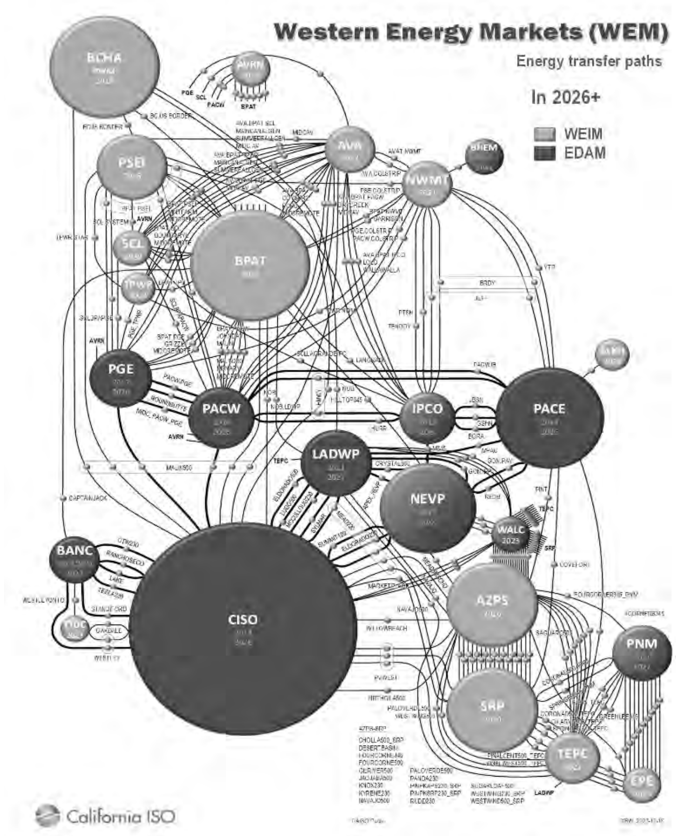
FIGURE HOLLAND-DIRECT-1



9. Q. PLEASE DISCUSS THE EXISTING MARKET DEVELOPMENT REGULATORY ASSET.

A. In the March 24, 2023, Order in Docket No. 22-09006, the Commission partially accepted the Companies' request for a regulatory asset to recover the costs of joining a Regional Transmission Organization ("RTO"). The Commission considered the Companies' proposal to participate in the development of both day-ahead market options (CAISO and SPP) a "reasonable strategy to maintain optionality as various day-ahead markets develop."[12] The Commission generally supported continued development of such markets, "which could potentially reduce energy costs for customers and help better integrate renewables in

[12] Docket No. 22-09006, *Order*, at 153, ¶ 392 (Mar. 24, 2023).

Nevada."[13] Nevertheless, the Commission approved the establishment of a regulatory asset only for costs, "directly related to fees required to fund the two day-ahead markets (CAISO and SPP) being developed as incremental steps towards a full RTO" and limited "NV Energy to recovering market development costs through 2025."[14] As a further compliance requirement, the Commission determined that in the 2024 Joint Integrated Resource Plan ("IRP"), the Companies' were to provide "a comprehensive plan to meet SB 448's requirement to join an RTO by 2030, including another proposal for cost recovery for costs related to market development."[15]

10. Q. WHAT COSTS HAVE BEEN BOOKED TO THE REGULATORY ASSET?

A. The regulatory asset and its inclusion in revenue requirement is discussed in the direct testimony of Jenny Naughton, but its contents are comprised of payments to SPP to support the Companies' voting participation in the Phase 1 design of Market+ and preparation of the FERC tariff filing. In accordance with the Phase 1 Funding Agreement, the Companies were responsible for a load ratio share of 9.8 percent of SPP's initial $9.7 million budget for a total of $953,122. After the expenditure of these funds, SPP charged Phase 1 participants ongoing costs of $500,000/month. Following the withdrawal of Western Area Power Administration Desert Southwest and Arizona Electric Power Cooperative, Inc., the Companies' share increased to 10.1 percent.

Following the Companies' internal determination to participate in EDAM, they submitted their Notice of Intent to Terminate to SPP on May 24, 2024. In

[13] *Id.*
[14] *Id*. at 153, ¶¶ 391-92.
[15] *Id*. at 154, ¶ 394.

accordance with the Phase 1 Funding Agreement, the Companies submitted a final letter of termination on June 23, 2024, 30 days after the Notice of Intent. The Companies' termination from Markets+ Phase 1 cost responsibilities was effective June 23, 2024.

11. Q. IF THE COMPANIES HAVE BEEN EXPLORING BOTH DAY-AHEAD MARKET OPTIONS, WHY WERE NO COSTS BOOKED FOR THE COMPANIES' PARTICIPATION IN EDAM?

A. The CAISO did not charge market participants separately for the costs associated with development of EDAM. The Commission's Order in Docket No. 22-09006 specifically excluded any staff or labor costs of the Companies. Accordingly, there were no EDAM-related expenditures of the Companies' labor included in the market regulatory asset.

III. <u>NEW EDAM IMPLEMENTATION COSTS REGULATORY ASSET PROPOSAL</u>

12. Q. PLEASE DESCRIBE THE PURPOSE OF THE PROPOSED EDAM IMPLEMENTATION COSTS REGULATORY ASSET, AND WHY IT IS APPROPRIATE TO APPROVE THE REGULATORY ASSET IN THIS RATE CASE?

A. In the 2024 Joint IRP, the Companies announced their intention to seek authorization from the Commission to expand the Companies' current participation in the EIM to the new EDAM. Pursuant to the criteria adopted by the Commission in Docket No. 23-10019, topics in an application by the Companies requesting permission to join EDAM must include but are not limited to: (1) costs of utility participation in the [EDAM], including fees, metering and software requirements; and (2) an applicable timeline for joining the market. The Company hopes to be in a position to submit the application to the Commission by July 2025. However, in order to: (1) develop the information required by the Commission and (2) develop initial budget and schedule estimates for EDAM implementation, the Companies need to perform a “Gap Analysis” – a study that examines what changes to current systems and personnel will be needed to transition from EIM participation to joining EDAM.

This Gap Analysis will help fulfill the filing requirements. This study needs to be accomplished to gather the relevant information necessary for the request to join EDAM. The Companies have retained Utilicast, an energy and utilities consulting service, who has done similar work for other potential EDAM participants, to perform the Gap Analysis. Utilicast will review the EDAM tariff and the current state of EDAM implementation and evaluate the impacts of the proposed rules on company staff, processes, and technologies to identify gaps. Once these gaps are identified, a cost-estimating model will be used to determine potential cost ranges. An implementation schedule will also be provided to support future planning.

13. Q. WHAT TYPES OF INCREMENTAL COSTS AND ACTIVITIES WOULD BE DEFERRED INTO THE NEW REGULATORY ASSET?

A. The Companies propose to include the following items in the regulatory asset specific to EDAM implementation:

- CAISO Implementation agreement;
- Utilicast, costs; and
- Software, metering, telecommunications.

Costs would be allocated between Nevada Power and Sierra in the same manner as was ordered by the Commission for the RTO regulatory asset, thus 75 percent to Nevada Power and 25 percent to Sierra.

14. Q. DOES PARTICIPATION IN A DAY-AHEAD MARKET MEET THE REQUIREMENTS OF SENATE BILL 448? [16]

A. No. As the Companies explained in the February 16, 2024, response in FERC investigatory Docket No. ER23-10019, the Companies support participation in an organized day-ahead market to capture additional customer benefits, beyond those currently being realized through the Companies' participation in the EIM. A day-ahead market may serve as a pathway to the Companies joining an RTO in the future.

15. Q. DO THE COMPANIES CURRENTLY HAVE ANY VIABLE OPTIONS TO JOIN AN RTO?

A. No. Senate Bill 448 ("SB448") recognized the potential for RTO participation to bring benefits to Nevada, if such participation is: (1) viable and (2) in the best interests of the Companies and customers. The Companies understand that, to be viable, the RTO must meet all of the identified statutory criteria,[17] including the requirement that governance be independent.[18] Viability also includes interconnectivity – the Companies must have sufficient transmission interchange with a footprint of sufficient size and resource diversity to secure

[16] Senate Bill 448 (2021) is codified at NRS 704.79881-704.7989.

[17] NRS 704.79882.

[18] NRS 704.79882(7) states: "Has a structure of governance or control that is independent of the users of the transmission facilities, and no member of its board of directors has an affiliation with a user or with an affiliate of a user during the member's tenure on the board so as to unduly affect the regional transmission organization's performance."

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the potential benefits of coordinated dispatch. "Best interests" includes reliability, economic, and environmental regulatory compliance components.

The CAISO's Board of Governors, selected by the Governor of California, is not independent. While the Companies have participated in the West-Wide Governance Pathway's Initiative, it is uncertain that the end result will be an RTO with full independent governance that the Companies can join. However, it is certainly possible that additional services performed by CAISO (for example co-optimization of ancillary service procurement or use of financial rather than physical rights for transmission service) could be added to the EIM/EDAM platform under the auspices of the revised governance structure.

In addition, the Companies lack direct connectivity with the current SPP RTO and the expected footprint of SPP's anticipated RTO West expansion.[19] Furthermore, the Companies understand that Markets+ and RTO West will not be combined in a single optimization at the start of their operations. Thus, it is unclear if the Markets+ participants will choose to expand market services within the separate Markets+ governance and operating regime rather than combine with SPP's existing RTO operations, including RTO West. It is also undetermined what those expanded services might include and if they will meet the SB448 criteria.

[19] At this time, the entities expected to participate in RTO West include Basin Electric Power Cooperative, Colorado Springs Utilities, Deseret Power Electric Cooperative, Municipal Energy Agency of Nebraska, Platte River Power Authority, Tri-State Generation and Transmission Association, and Western Area Power Administration (Upper Great Plains-West region, Colorado River Storage Project, and Rocky Mountain region). RTO West is projected to commence operation in 2026. https://www.spp.org/western-services/rto-expansion/

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

16. Q. WITHOUT A VIABLE OPTIONS TO JOIN AN RTO, HOW THE COMPANIES INTEND TO PROCEED?

A. The Companies have proposed to proceed along the following roadmap:

First, the Companies will make a filing to propose participation in a day-ahead market. While the Companies will provide the full evidentiary basis for its selection in that filing, the Companies anticipate seeking permission for the Commission to expand its current EIM participation to EDAM. The positive experience with EIM has generated significant economic, reliability, and environmental benefits for customers according to studies conducted by Brattle[20] and Energy and Environmental Economics.[21] The Companies interconnectivity with announced EDAM participants, and comparison of the core market design elements are among the factors that will support the request.

Second, the Companies will execute the required implementation agreement with CAISO and begin the systems upgrade and development work necessary for EDAM participation. The Companies will also proceed with the required modifications to their OATT. In all of these activities, the Companies will seek to benefit from the experience of the first movers and other EDAM participants.

Third, the Companies will continue to explore western market enhancements with respect to EDAM and other western initiatives. FERC-jurisdictional RTOs share a number of common characteristics including:

[20] Information on the Brattle study can be found on NV Energy's OASIS under the Western Market Development tab at https://www.oasis.oati.com/NEVP/.

[21] Information on the Western Markets Exploratory Group study can be found on NV Energy's OASIS under the Western Market Development tab at https://www.oasis.oati.com/NEVP/.

(1) Independent governance;
(2) Operate a real-time market;
(3) Operate a day-ahead market;
(4) Operate a market for co-optimized, ancillary services;
(5) Offer flow-based transmission with financial transmission rights;
(6) Depancake transmission access charges for service within the RTO's footprint;
(7) Perform joint transmission planning and utilize a defined cost allocation methodology;
(8) Implement a common resource adequacy program; and
(9) Serve as the Reliability Coordinator

EIM and EDAM meet characteristics (2) and (3) and partially (5) and (6). The Western Power Pool's Resource Adequacy Program partially satisfies (8) and NorthernGrid partially satisfies (7). It is likely that the day-ahead market operators will consider adding additional services. Given the potential savings from better utilization of the existing transmission structure as a means of achieving decarbonization objectives at the lowest reasonable cost, further regional market expansion is necessary.

Fourth, the Companies will regularly inform the Commission, the Regulatory Operations Staff, customers, and other stakeholders of ongoing Western Market activities. In compliance with the March 23, 2023, Order in Docket No. 22-09006, the Companies set up a webpage on the Companies' OASIS site that displays the Companies' Western Market Development and participation efforts.

Fifth, as January 1, 2027, approaches, the Companies will consider whether the Companies are in a position to join an RTO that conforms with the criteria provided for in NRS 704.79882,[22] or whether to seek a waiver or delay. Events in the West are too fluid and the requirements dates still far enough out to make any judgments about the Companies' ability to meet the January 1, 2030 requirement. As it has with respect to the development of EDAM, Markets+, the Western Resource Adequacy Program, the West-Wide Governance Pathway Initiative and any other proposed expansion of organized Western wholesale electric market participation, the Companies will continue to make all reasonable efforts to comply with the SB448 mandate.

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

A. Yes.

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[22] NRS 704.79882 states: "Regional transmission organization" means an entity established for the purpose of coordinating and efficiently managing the dispatch and transmission of electricity among public utilities on a multistate or regional basis that:

(1) Is approved by the Federal Energy Regulatory Commission;
(2) Effectuates separate control of transmission facilities from control of generation facilities;
(3) Implements, to the extent reasonably possible, policies and procedures designed to minimize pancaked transmission rates;
(4) Improves service reliability within this State;
(5) Achieves the objectives of an open and competitive wholesale electric generation marketplace, elimination of barriers to market entry and preclusion of control of bottleneck electric transmission facilities in the provision of retail electric service;
(6) Is of sufficient scope or otherwise operates to substantially increase economical supply options for customers;
(7) Has a structure of governance or control that is independent of the users of the transmission facilities, and no member of its board of directors has an affiliation with a user or with an affiliate of a user during the member's tenure on the board so as to unduly affect the regional transmission organization's performance;
(8) Operates under policies that promote positive performance designed to satisfy the electricity requirements of customers;
(9) Has an inclusive and open stakeholder process that does not place unreasonable burdens on or preclude meaningful participation by any stakeholder group;
(10) Promotes and assists new economic development in this State; and
(11) Is capable of maintaining real-time reliability of the transmission system, ensuring comparable and nondiscriminatory access and necessary service, minimizing system congestion and further addressing real or potential transmission constraints.

EXHIBIT HOLLAND-DIRECT-1

STATEMENT OF QUALIFICATIONS

Michael Holland
Vice President, Resource Optimization
NV Energy
6226 West Sahara Avenue
Las Vegas, NV 89151
702.321.0796
Michael.Holland@NVEnergy.com

Professional Experience

NV Energy, Las Vegas, NV
Vice President, Resource Optimization, December 2024-Present

- Responsible for directing the development and execution of strategies to maximize the value of NV Energy's portfolio of energy supply resources through oversight of NV Energy's day ahead and real time operations analytics and trading activities around power, natural gas, carbon credit allowances, and coal
- Oversight of NV Energy's renewable origination activities
- Oversight of the contract management tasks for NV Energy's owned and contracted resources

BHE Renewables, Des Moines, IA
Director, Energy Trading, August 2022-December 2024

- Managed a team of power traders responsible for a generation portfolio spread across six markets
- Managed a team of natural gas traders responsible for retail and gas generation supply
- Responsible for trading capacity and renewable energy credits in multiple markets across the United States
- Directed teams responsible for onboarding new generation and coordinating market integration
- Provided due diligence expertise in both pricing and transmission for potential acquisitions and projects

NV Energy, Las Vegas, NV
Manager, Power and Gas Trading, July 2021-August 2022

- Managed a team of power traders responsible for managing both the short and long-term power positions

- Managed a team of gas traders responsible for the procurement of natural gas to supply both power plants and end-use customers
- Responsible for multiple Requests for Proposals (RFPs) yearly to ensure power and natural gas needs are met at the best price

Senior Power Trader, June 2018-July 2021

- Optimized NV Energy's generation portfolio and executed day-ahead power transactions consistent with the Company's risk management guidelines
- Administered multiple RFPs to fill seasonal power needs

Macquarie Energy, Houston. TX
Senior Real-Time Trader, November 2010-June 2018

- Traded hourly physical and virtual power in PJM, MISO, CAISO, SWPP, ERCOT, MIDC, and NYISO markets

Ameren UE, St. Louis, MO
Real-Time Power Trader, May 2008- October 2010

- Utilized various generation assets, physical trades, and virtual bids and offers to actively manage the real-time position to maximize profits and mitigate risk.

Education

Tulane University, Freeman School of Business, New Orleans, LA
Master of Business Administration – 2008

United States Naval Academy, Annapolis, MD
Bachelor of Science, English - 1999

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, MICHAEL HOLLAND, 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: February 14, 2025

Michael Holland

HAROLD WALKER III

NEVADA POWER COMPANY D/B/A NV ENERGY
LAS VEGAS, NEVADA

DIRECT TESTIMONY
OF
HAROLD WALKER, III

CONCERNING
LEAD-LAG STUDY
FOR DETERMINATION OF CASH WORKING CAPITAL

JANUARY 2025

Prepared by:

GANNETT FLEMING

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 25-02____
2025 General Rate Case

Revenue Requirement

Prepared Direct Testimony of

Harold Walker III

TABLE OF CONTENTS

I. INTRODUCTION

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

A. My name is Harold Walker, III. My business address is 1010 Adams Avenue, Audubon, Pennsylvania, 19403. I am filing testimony on behalf of Nevada Power Company d/b/a NV Energy ("Nevada Power" or the "Company").

2. Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Gannett Fleming Valuation and Rate Consultants, LLC, as Manager, Financial Studies.

3. Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND EMPLOYMENT EXPERIENCE?

A. My educational background, business experience and qualifications are provided in **Exhibit Walker-Direct-1**.

II. SCOPE OF TESTIMONY

4. Q. WHAT IS THE SCOPE OF YOUR TESTIMONY

A. The purpose of my testimony is to recommend the appropriate electric revenue lag days and expense lead days for the determination of the cash working capital allowance on which Nevada Power should be afforded an opportunity to earn as part of its rate base for its Nevada jurisdictional electric service operations.[1]

[1] The Company's expense lead days include lead days for operations and maintenance ("O&M") expenses, taxes and interest expense.

My recommendation is based upon the results of a lead-lag analysis conducted for Nevada Power's electric service operations. My testimony is supported by **Exhibit Walker-Direct-2**.

III. PRINCIPLES OF WORKING CAPITAL

5. Q. PLEASE EXPLAIN THE RATEMAKING PRINCIPLES CONCERNING THE INCLUSION OF WORKING CAPITAL AS AN ELEMENT OF RATE BASE.

A. The working capital allowance is a component of rate base. A utility's need to recover the cost of working capital was first recognized in the noted U.S. Supreme Court case, *Smyth v. Ames*.[2] Among the many benchmarks established in the case was the "property devoted to public use doctrine" as a basis for fixing rates. The case recognized that among the matters to be considered in determining the value of property used was "the sum required to meet operating expenses."[3] Since that time, working capital required to meet operating expenses has generally been recognized as a proper item to be included in the rate base on which a utility is entitled to earn a return.

The rationale for the inclusion of operating working capital in rate base is to compensate investors for the use of that amount of their funds over and above their investment in plant. Operating working capital bridges the gap between the time funds are provided by investors to meet operating expenses incurred to provide service to customers and the time the revenue is received from those customers as reimbursement for the costs of these services.

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[2] *Smyth v. Ames*, 169 U.S. 466 (1898), overruled on other grounds by *Fed Power Comm'n v. Nat. Gas Pipeline Co. of Am.*, 315 U.S. 575, 586 (1942). Specifically, *Fed. Power Comm'n* departed from the holding in *Smyth* that fair market value in cost of service ratemaking must be used and instead concluded that "[t]he Constitution does not bind rate-making bodies to the service of any single formula or combination of formulas."
[3] *Id*. at 547.

IV. SUMMARY OF WORKING CAPITAL

6. Q. WHAT ARE THE COMPONENTS OF THE COMPANY'S WORKING CAPITAL?

A. Nevada Power's working capital is comprised of materials and supplies, prepayments and "other" elements. My testimony presents the revenue lag days and expense lead days used to determine the cash working capital component of the Company's total working capital. The materials and supplies, prepayments and "other" elements of Nevada Power's working capital are included in the direct testimony of various Company witnesses. My recommended revenue lag days and expense lead days are based upon the results of a lead-lag analysis conducted for Nevada Power's electric service operations. A summary of Nevada Power's revenue lag days and expense lead days is shown on page 2 of **Exhibit Walker-Direct-2**.

V. LEAD-LAG STUDY

7. Q. WHAT DOES A LEAD-LAG STUDY MEASURE AND HOW IS IT MEASURED?

A. The lead-lag study in this testimony measures the level of funding required to operate on a day-to-day basis in providing for the cost of O&M expenses, taxes and interest expense. This is measured by calculating the net lag between the amount of time elapsed between when a company provides a service to its customers and when the company receives payments from its customers, and the amount of time elapsed between when a company receives goods and services and when the company pays its suppliers for those goods and services. The difference between these two elapsed periods of time is known as the "net lag."

The net lag is multiplied by the average daily cost of O&M expenses, taxes and interest expense items to determine the cash working capital. Cash working capital for O&M expenses, taxes and interest expense is included in rate base to compensate investors for the use of their funds over and above their investment in plant, and to provide investors with a return on the funds required by a company for daily operations.

8. Q. WHAT ARE THE COMPONENTS OF A LEAD-LAG STUDY?

A. There are two primary elements of a lead-lag analysis: revenue lags and expense leads. The revenue lag is the sum of two distinct components: the service period lag and the payment lag.[4] The revenue lag is the elapsed time between the delivery of a company's product to its customers and when a company receives payment for the delivery of the product. Investor-provided funds are required to keep a company running during the revenue lag time period, when the revenue stream is temporarily insufficient to finance daily operational needs.

The expense lead is the sum of two distinct factors: the service lead and the payment lead. The expense lead is the elapsed time between when a good or service is provided to a company and when a company pays its supplier for the good or service. During the expense lead time period, cash received from customers may temporarily exceed a company's payments to its suppliers for goods or services, and the excess may be used to repay investor-provided funds. The net difference between the revenue lag and expense lead denotes a company's cash working capital requirement.

9. Q. WHAT TIME PERIOD DOES YOUR LEAD-LAG STUDY ENCOMPASS?

[4] The payment lag includes the billing lag and the collection lag.

A. The lead-lag study in this case analyzed the revenues and the associated cost of O&M expenses, taxes and interest expense during the 12 months ended September 30, 2024 ("Test Year") to derive the appropriate lag (lead) days. While the lead and lag days were calculated from Test Year results, the expenses that they are applied to are for the Company's Certification Period ended February 28, 2025.

10. Q. WAS THE LEAD-LAG STUDY THAT YOU CONDUCTED FOR THE COMPANY PREPARED USING SIMILAR METHODS AND TECHNIQUES IN PRIOR FILINGS?

A. Yes. The methodology used in the lead-lag study is fundamentally the same as that used in the Company's prior lead-lag studies filed with the Public Utilities Commission of Nevada ("Commission").

11. Q. WHAT DATA SET DID YOU UTILIZE IN YOUR LEAD-LAG STUDY?

A. The lead-lag study reflects information provided by the Company. Once the data was provided, data validation was performed by comparing an actual invoice or a bill with data from Nevada Power's systems to ensure accuracy.

The revenue lag data set was developed from each rate schedule. For rate schedules with the largest customer counts, such as residential and general service, a statistical sample was taken of random accounts selected using a computer model that queried the database containing customer billing information for each month of the test year. The revenue lags for all other rate schedules were determined by analyzing the individual lag days for all customers served under each rate schedule during the Test Year.

The expense lead data sets were developed in a similar method and reflect the service beginning and ending dates, the amount purchased, and the date of payment. For the largest expense item (goods and services), a statistical sample was taken of random accounts selected using a computer model that queried the database containing vendor billing information for each month of the Test Year. The expense leads for all other expense items were determined by analyzing the individual lead days for all vendors in the account during the Test Year to reflect the service beginning and ending dates, the amount purchased and the date of payment.

VI. RESULTS OF THE LEAD-LAG STUDY

12. Q. WHAT ARE THE RESULTS OF THE LEAD-LAG STUDY?

A. Page 2 of **Exhibit Walker-Direct-2** sets forth the results of the lead-lag study and summarizes the revenue lag days and the expense lead days. The revenue lag days were determined to be 38.72 days and the various expense lead days, determined by line item, range from negative -13.71 days to 350.96 days.

13. Q. PLEASE EXPLAIN THE PROCEDURES USED TO DETERMINE THE REVENUE LAG.

A. Page 3 of **Exhibit Walker-Direct-2** (Schedule I) summarizes the development of the 38.72 revenue lag days. The lag days for revenue is comprised of the service period lag and the payment lag.

14. Q. PLEASE EXPLAIN THE PROCEDURES USED TO DETERMINE THE SERVICE PERIOD LAG DAYS FOR REVENUE.

A. The service period lag is the average time between actual meter readings of 30.42 days based on monthly billing (365 days ÷ 12 months). The average time between meter readings, 30.42 days, is divided by two to produce a midpoint—a service period lag of 15.21 days. A midpoint is used because it is assumed service is provided evenly over the service period.

15. Q. PLEASE DESCRIBE THE PROCEDURE USED TO CALCULATE THE PAYMENT LAG PORTION OF THE REVENUE LAG.

A. The payment lag is the average number of days from the meter read date and the date customers' payments are received. This was determined for each customer or each customer sampled and produced an average payment lag of 23.51 days for the Company.

16. Q. PLEASE SUMMARIZE THE TOTAL REVENUE LAG.

A. The total revenue lag of 38.72 lag days for Nevada Power is shown on page 3 of **Exhibit Walker-Direct-2** (Schedule I). It includes a 15.21-day service period lag and a payment lag of 23.51 days.

17. Q. PLEASE EXPLAIN THE CALCULATION OF EXPENSE LEAD DAYS SHOWN ON PAGE 2 OF EXHIBIT WALKER-DIRECT-2.

A. The expense lead days shown on page 2 are comprised of three major sub-accounts: O&M expenses, taxes, and interest expense. For the expense items shown, the lead days were generally calculated for each invoice or account based on the midpoints of the service periods to the dates the Company paid the invoices or accounts.[5]

18. Q. HOW WERE THE LEAD DAYS DETERMINED FOR THE OTHER O&M EXPENSES SHOWN ON PAGE 2 OF EXHIBIT WALKER-DIRECT-2?

A. For the other O&M expenses shown, the lead days were determined for each invoice or account sampled based on the midpoints of the service periods to the dates the Company paid the invoices or accounts based on the actual data or a sampling of data.[6]

For example, the weighted average lead days for natural gas and natural gas transportation equal 39.86 days and is developed on page 6 of **Exhibit Walker-Direct-2**. The lead days for natural gas and natural gas transportation expense were calculated for each invoice examined based on the midpoints of the service periods to the dates the Company paid the invoices.

Similar analyses were conducted for other expense items: purchased power lead days of 35.26 days are developed on page 7; goods and services (Nevada) lead days of 35.77 days are developed on page 8; and labor lead days of 10.59 days are developed on page 14.

19. Q. PLEASE EXPLAIN HOW THE LEAD DAYS WERE DETERMINED FOR THE GOODS AND SERVICES EXPENSE SHOWN ON PAGE 2 OF EXHIBIT WALKER-DIRECT-2.

A. The goods and services expense line item lead days include a sampling of Nevada

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[5] As was the case with the revenue service period, a midpoint was generally used for the service lead because it is assumed service is provided evenly over the service period.

[6] For goods and services expenses, a statistical sample was taken of random accounts selected using a computer model that queried the database containing vendor billing information for each month of the test year.

Power invoices that were not included in the other O&M expense line items. The supporting information used to determine the 35.77 lead days is shown on pages 8-13 and reflects the sampling process described previously. The lead days for goods and services were calculated as the difference between the payment date and the actual beginning and ending service date for each voucher analyzed in order to calculate lead days in accordance with Commission's Order in Docket No. 08-12002.

20. Q. HOW WERE THE LEAD DAYS DETERMINED FOR THE TAX EXPENSES SHOWN ON PAGE 2 OF EXHIBIT WALKER-DIRECT-2?

A. For most of the taxes, the lead days were calculated based on the midpoint of the tax liability period to the payment date, weighted by the actual amount paid. The exception to this was income taxes, where the lead days were calculated based on the midpoint of the tax period to the payment date, weighted by the percent of the payment required. The taxes line items shown on page 2 include: mill tax lead days of 138.21 days (developed on page 15); possessory interest tax (Navajo) lead days of 86.52 days (developed on page 16); Nevada use tax on Purchasing Card (P Card) lead days of 15.30 days (developed on page 17); property tax (Arizona) lead days of 212.71 days (developed on page 18); unemployment tax lead days of 76.38 days (developed on page 19); Nevada modified business tax lead days of 36.71 days (developed on page 20); FICA lead days of 11.00 days (developed on page 21); franchise tax Nevada counties lead days of 350.96 days (developed on page 22); federal income tax lead days of 28.39 days (developed on page 23); and Nevada commerce tax lead days of 228.17 days (developed on page 26).

21. Q. HOW WERE THE LEAD DAYS DETERMINED FOR THE INTEREST EXPENSES SHOWN ON PAGE 2 OF EXHIBIT WALKER-DIRECT-2?

A. For the interest expense line items shown, the lead days were calculated based on the midpoint of the interest liability period to the payment date. The interest expense line items shown on page 2 include: long-term debt lead days of negative -13.71 days (developed on page 24); deposits lead days of 105.00 days (developed on page 25); and leases lead days of negative -6.14 days (developed on page 27).

22. Q. PLEASE DESCRIBE THE METHODOLOGY USED TO CALCULATE LEAD DAYS FOR LONG-TERM DEBT EXPENSE SHOWN ON PAGE 2 OF EXHIBIT WALKER-DIRECT-2.

A. The lead days for long-term debt expense was determined for each interest payment made during the test period using a two-step process which combined (added) the service lead days and the payment lead days, weighted by the percentage of the interest payment required.

23. Q. IS THE LONG-TERM DEBT EXPENSE METHODOLOGY DIFFERENT FROM THAT USED IN RECENT CASES?

A. Yes, the prior practice grouped similar debt instruments together and aggregated their interest payments, while the new method involves a more detailed payment-by-payment calculation. This revised calculation more accurately reflects the frequency in which interest payments are made. The impact of this change is discussed in Statement P.

VII. CONCLUSION

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

A. Yes, it does.

EXHIBIT WALKER-DIRECT-1

NEVADA POWER COMPANY D/B/A NV ENERGY
LAS VEGAS, NEVADA

TO ACCOMPANY THE

DIRECT TESTIMONY

SUPPORTING

EXHIBIT WALKER-DIRECT-1
(EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS)

FOR
LEAD-LAG STUDY
FOR DETERMINATION OF CASH WORKING CAPITAL

JANUARY 2025

Prepared by:

GANNETT FLEMING

Professional Qualifications
of
Harold Walker, III
Manager, Financial Studies
Gannett Fleming Valuation and Rate Consultants, LLC.

EDUCATION

Mr. Walker graduated from Pennsylvania State University in 1984 with a Bachelor of Science Degree in Finance. His studies concentrated on securities analysis and portfolio management with an emphasis on economics and quantitative business analysis. He has also completed the regulation and the rate-making process courses presented by the College of Business Administration and Economics Center for Public Utilities at New Mexico State University. Additionally, he has attended programs presented by The Institute of Chartered Financial Analysts (CFA).

Mr. Walker was awarded the professional designation "Certified Rate of Return Analyst" (CRRA) by the Society of Utility and Regulatory Financial Analysts. This designation is based upon education, experience and the successful completion of a comprehensive examination. He is also a member of the Society of Utility and Regulatory Financial Analysts (SURFA) and has attended numerous financial forums sponsored by the Society. The SURFA forums are recognized by the Association for Investment Management and Research (AIMR) and the National Association of State Boards of Accountancy for continuing education credits.

Mr. Walker also obtained a license as a Municipal Advisor Representative (Series 50) by Municipal Securities Rulemaking Board (MSRB) and Financial Industry Regulatory Authority (FINRA).

BUSINESS EXPERIENCE

Prior to joining Gannett Fleming Valuation and Rate Consultants, LLC., Mr. Walker was employed by AUS Consultants - Utility Services. He held various positions during his eleven years with AUS, concluding his employment there as a Vice President. His duties included providing and supervising financial and economic studies on behalf of investor owned and municipally owned water, wastewater, electric, natural gas distribution and transmission, oil pipeline and telephone utilities as well as resource recovery companies.

In 1996, Mr. Walker joined Gannett Fleming Valuation and Rate Consultants, LLC. In his capacity as Manager, Financial Studies and for the past twenty-five years, he has continuously studied rates of return requirements for regulated firms. In this regard, he supervised the preparation of rate of return studies in connection with his testimony and in the past, for other individuals. He also assisted and/or developed dividend policy studies, nuclear prudence studies, calculated fixed charge rates for avoided costs involving cogeneration projects, financial decision studies for capital budgeting purposes and developed financial models for determining future capital requirements and the effect of those requirements on investors and ratepayers, valued utility property for acquisition and divestiture, and assisted in the private placement of fixed capital securities for public utilities.

Head, Gannett Fleming GASB 34 Task Force responsible for developing Governmental Accounting Standards Board (GASB) 34 services, and educating Gannett Fleming personnel and Gannett Fleming clients on GASB 34 and how it may affect them. The GASB 34 related services include inventory of assets, valuation of assets, salvage estimation, annual depreciation rate determination, estimation of depreciation reserve, asset service life determination, asset condition assessment, condition assessment documentation, maintenance estimate for asset preservation, establishment of condition level index, geographic information system (GIS) and data management services, management discussion and analysis (MD&A) reporting, required supplemental information (RSI) reporting, auditor interface, and GASB 34 compliance review.

In 2004, Mr. Walker was elected to serve on the Board of Directors of SURFA. Previously, he served as an ex-officio director as an advisor to SURFA's existing President. In 2000, Mr. Walker was elected President of SURFA for the 2001-2002 term. Prior to that, he was elected to serve on the Board of Directors of SURFA during the period 1997-1998 and 1999-2000. He also previously served on the Pennsylvania Municipal Authorities Association, Electric Deregulation Committee.

EXPERT TESTIMONY

Mr. Walker has submitted testimony or been deposed on various topics before regulatory commissions and courts in 29 states including: Alaska, Arizona, California, Colorado, Connecticut, Delaware, Hawaii, Idaho, Illinois, Indiana, Iowa, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Hampshire, Nevada, New Jersey, New York, North Carolina, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Vermont, Virginia, and West Virginia. His testimonies covered various subjects including lead-lag studies, fair rate of return, fair market value, the taking of natural resources, benchmarking, appropriate capital structure and fixed capital cost rates, depreciation, purchased water adjustments, synchronization of interest charges for income tax purposes, valuation, cash working capital, financial analyses of investment alternatives, and fair value. The following tabulation provides a listing of the electric power, natural gas distribution, telephone, wastewater, and water service utility cases in which he has been involved as a witness.

Client	Docket No.
Alpena Power Company	U-10020
Armstrong Telephone Company - Northern Division	92-0884-T-42T
Armstrong Telephone Company - Northern Division	95-0571-T-42T
Artesian Water Company, Inc.	90 10
Artesian Water Company, Inc.	06 158
Aqua Illinois Consolidated Water Divisions and Consolidated Sewer Divisions	11-0436
Aqua Illinois Hawthorn Woods Wastewater Division	07 0620/07 0621/08 0067
Aqua Illinois Hawthorn Woods Water Division	07 0620/07 0621/08 0067
Aqua Illinois Kankakee Water Division	10-0194
Aqua Illinois Kankakee Water Division	14-0419
Aqua Illinois Vermilion Division	07 0620/07 0621/08 0067
Aqua Illinois Willowbrook Wastewater Division	07 0620/07 0621/08 0067
Aqua Illinois Willowbrook Water Division	07 0620/07 0621/08 0067
Aqua Illinois, Inc.	24-0044
Aqua Pennsylvania, Inc	A-2022-3034143
Aqua Pennsylvania, Inc	R-2024-3047822
Aqua Pennsylvania, Inc	R-2024-3047824
Aqua Pennsylvania Wastewater Inc	A-2016-2580061
Aqua Pennsylvania Wastewater Inc	A-2017-2605434
Aqua Pennsylvania Wastewater Inc	A-2018-3001582
Aqua Pennsylvania Wastewater Inc	A-2019-3008491
Aqua Pennsylvania Wastewater Inc	A-2019-3009052
Aqua Pennsylvania Wastewater Inc	A-2019-3015173
Aqua Pennsylvania Wastewater Inc	A-2021-3024267
Aqua Pennsylvania Wastewater Inc	A-2021-3026132
Aqua Pennsylvania Wastewater Inc	A-2021-3027268
Aqua Pennsylvania Wastewater Inc	A-2023-3041695
Aqua Virginia - Alpha Water Corporation	Pue-2009-00059
Aqua Virginia - Blue Ridge Utility Company, Inc.	Pue-2009-00059

Aqua Virginia - Caroline Utilities, Inc. (Wastewater)	Pue-2009-00059
Aqua Virginia - Caroline Utilities, Inc. (Water)	Pue-2009-00059
Aqua Virginia - Earlysville Forest Water Company	Pue-2009-00059
Aqua Virginia - Heritage Homes of Virginia	Pue-2009-00059
Aqua Virginia - Indian River Water Company	Pue-2009-00059
Aqua Virginia - James River Service Corp.	Pue-2009-00059
Aqua Virginia - Lake Holiday Utilities, Inc. (Wastewater)	Pue-2009-00059
Aqua Virginia - Lake Holiday Utilities, Inc. (Water)	Pue-2009-00059
Aqua Virginia - Lake Monticello Services Co. (Wastewater)	Pue-2009-00059
Aqua Virginia - Lake Monticello Services Co. (Water)	Pue-2009-00059
Aqua Virginia - Lake Shawnee	Pue-2009-00059
Aqua Virginia - Land'or Utility Company (Wastewater)	Pue-2009-00059
Aqua Virginia - Land'or Utility Company (Water)	Pue-2009-00059
Aqua Virginia - Mountainview Water Company, Inc.	Pue-2009-00059
Aqua Virginia - Powhatan Water Works, Inc.	Pue-2009-00059
Aqua Virginia - Rainbow Forest Water Corporation	Pue-2009-00059
Aqua Virginia - Shawnee Land	Pue-2009-00059
Aqua Virginia - Sydnor Water Corporation	Pue-2009-00059
Aqua Virginia - Water Distributors, Inc.	Pue-2009-00059
Atlantic City Sewerage Company	WR21071006
Berkshire Gas Company	18-40
Berkshire Gas Company	22-20
Bermuda Water Company, Inc	W-01812A-22-0256
Borough of Brentwood	A-2021-3024058
Borough of Hanover	R-2009-2106908
Borough of Hanover	R-2012-2311725
Borough of Hanover	R-2014-242830
Borough of Hanover	R-2021-3026116
Borough of Hanover	P-2021-3026854
Borough of Royersford	A-2020-3019634
Butler Area Sewer Authority	A-2020-3019634
Chaparral City Water Company	W 02113a 04 0616
California-American Water Company	CIVCV156413
Citizens Utilities Company	

Colorado Gas Division	-
Citizens Utilities Company	
Vermont Electric Division	5426
Citizens Utilities Home Water Company	R 901664
Citizens Utilities Water Company	
of Pennsylvania	R 901663
City of Beaver Falls	A-2022-3033138
City of Bethlehem - Bureau of Water	R-00984375
City of Bethlehem - Bureau of Water	R 00072492
City of Bethlehem - Bureau of Water	R-2013-2390244
City of Bethlehem - Bureau of Water	R-2020-3020256
City of Dubois – Bureau of Water	R-2013-2350509
City of Dubois – Bureau of Water	R-2016-2554150
City of Lancaster Sewer Fund	R-00005109
City of Lancaster Sewer Fund	R-00049862
City of Lancaster Sewer Fund	R-2012-2310366
City of Lancaster Sewer Fund	R-2019-3010955
City of Lancaster Water Fund	R-00984567
City of Lancaster Water Fund	R-00016114
City of Lancaster Water Fund	R 00051167
City of Lancaster Water Fund	R-2010-2179103
City of Lancaster Water Fund	R-2014-2418872
City of Lancaster Water Fund	R-2021-3026682
City of Lancaster Water Fund	P-2022-3035591
Coastland Corporation	15-cvs-216
Commonwealth Edison Company	23-0728
Commonwealth Edison Company	24-0087
Community Utilities of Pennsylvania-Water	R-2023-3042804
Community Utilities of Pennsylvania-Wastewater	R-2023-3042805
Connecticut-American Water Company	99-08-32
Connecticut Water Company	06 07 08
Consumers Pennsylvania Water Company	
Roaring Creek Division	R-00973869
Consumers Pennsylvania Water Company	
Shenango Valley Division	R-00973972
Country Knolls Water Works, Inc.	90 W 0458
East Resources, Inc. - West Virginia Utility	06 0445 G 42T

Elizabeth Borough Municipal Authority	A-2023-3038717
Elizabethtown Water Company	WR06030257
ENSTAR Natural Gas Company	U-22-081
Falls Water Company, Inc.	FLS-W-23-01
Forest Park, Inc.	19-W-0168 & 19-W-0269
Hampton Water Works Company	DW 99-057
Hidden Valley Utility Services, LP	R-2018-3001306
Hidden Valley Utility Services, LP	R-2018-3001307
Illinois American Water Company	16-0093
Illinois American Water Company	22-0210
Illinois American Water Company	24-0097
Indian Rock Water Company	R-911971
Indiana Natural Gas Corporation	38891
Iowa American Water Company	RPU-2024-0002
Jamaica Water Supply Company	-
Kane Borough Authority	A-2019-3014248
Kentucky American Water Company, Inc.	2007 00134
Kentucky American Water Company, Inc.	2023-00191
Middlesex Water Company	WR 89030266J
Millcreek Township Water Authority	55 198 Y 00021 11
Missouri-American Water Company	WR 2000-281
Missouri-American Water Company	SR 2000-282
Missouri-American Water Company	WR-2022-0303
Missouri-American Water Company	SR-2022-0304
Mount Holly Water Company	WR06030257
Nevada Power Company d/b/a NV Energy	20-06003
Nevada Power Company d/b/a NV Energy	23-06007
New Jersey American Water Company	WR 89080702J
New Jersey American Water Company	WR 90090950J
New Jersey American Water Company	WR 03070511
New Jersey American Water Company	WR-06030257
New Jersey American Water Company	WR08010020
New Jersey American Water Company	WR10040260
New Jersey American Water Company	WR11070460
New Jersey American Water Company	WR15010035
New Jersey American Water Company	WR17090985
New Jersey American Water Company	WR19121516

New Jersey American Water Company	WR22010019
New Jersey American Water Company	WR24010056
New Jersey Natural Gas Company	GR19030420
New Jersey Natural Gas Company	GR21030679
New Jersey Natural Gas Company	GR24010071
Newtown Artesian Water Company	R-911977
Newtown Artesian Water Company	R-00943157
Newtown Artesian Water Company	R-2009-2117550
Newtown Artesian Water Company	R-2011-2230259
Newtown Artesian Water Company	R-2017-2624240
Newtown Artesian Water Company	R-2019-3006904
Newtown Artesian Water Company	R-2024-3050208
North Maine Utilities	14-0396
Northern Indiana Fuel & Light Company	38770
Oklahoma Natural Gas Company	PUD-940000477
Palmetto Utilities, Inc.	2020-281-S
Palmetto Wastewater Reclamation, LLC	2018-82-S
Pennichuck Water Works, Inc.	DW 04 048
Pennichuck Water Works, Inc.	DW 06 073
Pennichuck Water Works, Inc.	DW 08 073
Pennsylvania-American Water Company	A-2023-3039900
Pennsylvania Gas & Water Company (Gas)	R-891261
Pennsylvania Gas & Water Co. (Water)	R 901726
Pennsylvania Gas & Water Co. (Water)	R-911966
Pennsylvania Gas & Water Co. (Water)	R-22404
Pennsylvania Gas & Water Co. (Water)	R-00922482
Pennsylvania Gas & Water Co. (Water)	R-00932667
Philadelphia Gas Works	R-2020-3017206
Philadelphia Gas Works	R-2023-3037933
Public Service Company of North Carolina, Inc.	G-5, Sub 565
Public Service Electric and Gas Company	ER181010029
Public Service Electric and Gas Company	GR18010030
Presque Isle Harbor Water Company	U-9702
Sierra Pacific Power Company d/b/a NV Energy	19-06002
Sierra Pacific Power Company d/b/a NV Energy	22-06014
Sierra Pacific Power Company d/b/a NV Energy	24-02026
Sierra Pacific Power Company d/b/a NV Energy	24-02027

St. Louis County Water Company	WR-2000-844
Suez Water Delaware, Inc.	19-0615
Suez Water Idaho, Inc.	SUZ-W-20-02
Suez Water New Jersey, Inc.	WR18050593
Suez Water New Jersey, Inc.	WR20110729
Suez Water Owego-Nichols, Inc.	17-W-0528
Suez Water Pennsylvania, Inc.	R-2018-3000834
Suez Water Pennsylvania, Inc.	A-2018-3003519
Suez Water Pennsylvania, Inc.	A-2018-3003517
Suez Water Rhode Island, Inc.	Docket No. 4800
Suez Water Owego-Nichols, Inc.	19-W-0168 & 19-W-0269
Suez Water New York, Inc.	19-W-0168 & 19-W-0269
Suez Westchester, Inc.	19-W-0168 & 19-W-0269
Tennessee American Water Company	24-00032
Town of North East Water Fund	9190
Township of Exeter	A-2018-3004933
United Water New Rochelle	W-95-W-1168
United Water Toms River	WR-95050219
Upper Pottsgrove Township	A-2020-3021460
Valley Township (water)	A-2020-3019859
Valley Township (wastewater)	A-2020-3020178
Valley Water Systems, Inc.	06 10 07
Veolia Water Idaho, Inc.	VEO-W-22-02
Veolia Water Delaware, Inc.	23-0598
Veolia Water New Jersey, Inc.	WR23110790
Veolia Water New York, Inc.	23-W-0111
Veolia Water Pennsylvania, Inc.	R-2024-3045192
Veolia Water Pennsylvania, Inc.	R-2024-3045193
Virginia American Water Company	PUR-2018-00175
Virginia American Water Company	PUR-2021-00255
Virginia American Water Company	PUR-2023-00194
West Virginia-American Water Company	15-0676-W-42T
West Virginia-American Water Company	15-0675-S-42T
Wilmington Suburban Water Corporation	94-149
York Water Company	R-901813
York Water Company	R-922168
York Water Company	R-943053

York Water Company	R-963619
York Water Company	R-994605
York Water Company	R-00016236
Young Brothers, LLC	2019-0117

EXHIBIT WALKER-DIRECT-2

NEVADA POWER COMPANY D/B/A NV ENERGY
LAS VEGAS, NEVADA

TO ACCOMPANY THE

DIRECT TESTIMONY

SUPPORTING

EXHIBIT WALKER-DIRECT-2

FOR
LEAD-LAG STUDY
FOR DETERMINATION OF CASH WORKING CAPITAL

JANUARY 2025

Prepared by:

GANNETT FLEMING

Nevada Power Company d/b/a NV Energy
Lead-Lag Study
For the Twelve Months Ended September 30, 2024

Index to Exhibit Walker-Direct-2

Nevada Power Company d/b/a NV Energy
Revenue Lag / Expense Lead Summary
October 1, 2023 - September 30,2024

Description	Nevada Power 2024 Lag Days	Schedule
Revenue	38.72	I
Coal [(1)]	-	II
Diesel Oil [(1)]	-	III
Natural Gas	39.86	IV
Purchased Power	35.26	V
Goods and Services - Nevada	35.77	VI
Labor	10.59	VII
Mill Tax	138.21	VIII
Possessory Interest Tax Moapa[(2)]	-	IX(a)
Possessory Interest Tax Navajo	86.52	IX(b)
Nevada Use Tax on P Card	15.30	X
Property Tax - AZ	212.71	XI
Unemployment Tax	76.38	XII
Nevada Modified Business Tax	36.71	XIII
FICA	11.00	XIV
Franchise Tax Nevada Counties	350.96	XV
Federal Income Tax	28.39	XVI
Long-term Debt[(3)]	(13.71)	XVII
Deposits	105.00	XVIII
Nevada Commerce Tax	228.17	XIX
Leases[(4)]	(6.14)	XX
Average	68.08	
Count	21	

(1) Coal and Diesel Oil have no costs going forward.
(2) Moapa PIT has been discontinued and no payments made in 2023-2024.
(3) Long Term Debt has updated to more accurately reflect the timing of the payments.
(4) Leases includes all leases and not just Pearson or GOB as historic numbers do.

Nevada Power Company d/b/a NV Energy
Revenue Lag Days
October 1, 2023 - September 30,2024

Schedule I
Lead Lag Study

R/S Count: 139

Weighted Avg Lag	23.51
Midpoint	15.21
Total Lag Days:	38.72

Activity Code	Rate Schedule	Revenue	Rev %	Dollar Days	ARAPPL	Avg Lag Days	Weighted Avg Lag
R200	RS-NEM	(49,162.72)	0.00%	1,007,521.21	41,952.94	24.02	0.000
R213	RS-NEM	(37,239.20)	0.00%	916,122.17	32,284.04	28.38	0.000
R241	RS	(17,638.42)	0.00%	496,752.29	14,689.02	33.82	0.000
R247	RS-NEM	1,191,445.92	-0.04%	907,320.42	39,657.60	22.88	(0.009)
R248	RS-NEM	(103,576.85)	0.00%	1,511,169.94	64,881.11	23.29	0.001
R249	RS-NEM	(760,155.85)	0.03%	4,060,230.15	182,435.08	22.26	0.006
R271	ORS-NEM	(25,338.25)	0.00%	453,943.02	22,149.79	20.49	0.000
R272	ORS-NEM	(70,839.30)	0.00%	1,034,775.71	49,176.88	21.04	0.001
R273	ORS-NEM	(358,484.18)	0.01%	3,651,392.56	154,434.40	23.64	0.003
R274	ORS-NEM EVRR	(9,566.63)	0.00%	168,970.97	7,958.54	21.23	0.000
R275	ORS-NEM EVRR	(41,402.75)	0.00%	910,047.66	37,407.16	24.33	0.000
R276	ORS-NEM EVRR	(236,926.51)	0.01%	2,869,184.93	115,572.54	24.83	0.002
R279	ORM-NEM	(510.74)	0.00%	1,827.82	86.18	21.21	0.000
R294	ORS-NEM CPP	(1,513.81)	0.00%	60,126.79	859.57	69.95	0.000
R334	ORS-TOU	(21,226.71)	0.00%	346,562.59	20,319.64	17.06	0.000
R335	ORS-TOU EVRR	(2,264.82)	0.00%	34,219.68	1,328.30	25.76	0.000
R340	ORS-NEM	(31,517.03)	0.00%	637,275.74	26,377.42	24.16	0.000
R341	ORS-NEM EVRR	(11,802.22)	0.00%	273,015.68	12,505.01	21.83	0.000
R346	ORS-NEM	(7,235.41)	0.00%	122,411.03	6,656.17	18.39	0.000
R347	ORS-NEM EVRR	(18,216.39)	0.00%	318,061.27	14,829.84	21.45	0.000
R803	LGS-1	(15,831.99)	0.00%	51,626.03	11,004.43	4.69	0.000
R900	LGS-2P	(316,482.55)	0.01%	11,725,079.71	282,039.62	41.57	0.005
X051	RS-NEM	(9,684,746.79)	0.34%	6,418,223.93	292,391.22	21.95	0.074
X056	RM-NEM	(42,405.55)	0.00%	773,886.08	28,945.90	26.74	0.000
X062	RS-FLEX	(25,319,907.34)	0.88%	9,046,386.18	434,042.75	20.84	0.183
X063	RM-FLEX	(17,503,521.08)	0.61%	3,590,811.21	208,495.06	17.22	0.104
X064	LRS-FLEX	(360.67)	0.00%	16,652.25	123.35	135.00	0.000
X065	RS-NEM	(24,592,442.76)	0.85%	8,986,565.10	411,347.28	21.85	0.186
X070	RM-NEM	(126,671.97)	0.00%	1,211,435.54	50,510.41	23.98	0.001
X075	LRS-NEM	(60,929.52)	0.00%	1,236,117.98	58,909.37	20.98	0.000
X080	RS-NEM	(505,567.25)	0.02%	4,846,080.93	228,878.98	21.17	0.004
X083	RM-NEM	(1,631.65)	0.00%	34,780.98	1,285.34	27.06	0.000
X100	RS	(1,098,160,339.11)	38.05%	14,183,323.69	647,506.64	21.90	8.333
X102	RM	(334,408,396.38)	11.59%	6,363,671.91	236,015.13	26.96	3.124
X103	LRS	(5,406,174.38)	0.19%	70,817,914.15	3,460,676.79	20.46	0.038
X104	ORS-TOU OPT A	(1,067,006.29)	0.04%	4,346,930.40	212,034.21	20.50	0.008
X110	GS	(83,784,695.76)	2.90%	5,623,938.04	264,741.68	21.24	0.617
X112	OGS-TOU	(3,539,976.30)	0.12%	8,555,770.20	436,337.22	19.61	0.024
X113	OGS-TOU EVRR	(2,955.79)	0.00%	56,291.88	2,964.74	18.99	0.000
X120	LGS-1	(508,394,828.55)	17.62%	83,654,542.23	3,802,685.22	22.00	3.876
X121	SSR-III LGS-1	(153,493.60)	0.01%	4,213,810.88	149,465.97	28.19	0.001
X122	OLGS-1 TOU	(14,344,501.34)	0.50%	66,543,253.19	3,521,779.70	18.89	0.094
X124	LGS-2P	(6,201,914.66)	0.21%	20,883,267.51	984,832.09	21.20	0.046
X125	LGS-2S	(273,949,827.78)	9.49%	1,078,240.65	35,359.84	30.49	2.894
X126	LGS-2T	(64,397.73)	0.00%	15,085,419.59	208,358.24	72.40	0.002
X127	LGS-3P	(166,686,761.62)	5.78%	802,469,826.86	34,319,481.95	23.38	1.350
X128	LGS-3S	(88,238,199.51)	3.06%	970,184,219.32	42,186,261.48	23.00	0.703
X129	LGS-3T	(26,675,542.27)	0.92%	477,893,161.24	23,352,360.14	20.46	0.189
X136	OLGS-3P-HLF	(28,121,569.46)	0.97%	435,332,447.74	23,212,318.93	18.75	0.183
X137	LSR-II LGS-3P	(3,147,248.77)	0.11%	2,054,807.56	78,969.43	26.02	0.028
X138	LSR-II LGS-3T	(10,806,393.16)	0.37%	58,739,375.42	1,790,211.43	32.81	0.123
X143	LSR-I LGS-2T	(1,104,373.60)	0.04%	30,718,704.18	888,527.54	34.57	0.013
X155	MPE	(432,207.34)	0.01%	17,273,117.30	266,086.59	64.92	0.010
X157	MPE	(2,079,207.16)	0.07%	55,816,026.12	2,133,214.92	26.17	0.019
X164	LGS-2S-WP	(1,972,777.93)	0.07%	2,026,945.45	85,693.21	23.65	0.016

Nevada Power Company d/b/a NV Energy **Schedule I**
Revenue Lag Days Lead Lag Study
October 1, 2023 - September 30,2024

R/S Count: 139

Weighted Avg Lag	23.51
Midpoint	15.21
Total Lag Days:	38.72

Activity Code	Rate Schedule	Revenue	Rev %	Dollar Days	ARAPPL	Avg Lag Days	Weighted Avg Lag
X166	LGS-3P-WP	(1,540,303.87)	0.05%	60,427,817.22	1,357,170.22	44.52	0.024
X181	SL	(11,158,072.41)	0.39%	317,645,829.75	10,057,539.50	31.58	0.122
X190	GS-NEM	(21,124.25)	0.00%	501,355.35	17,366.58	28.87	0.000
X193	GS-NEM	(224,289.35)	0.01%	2,241,308.04	102,900.20	21.78	0.002
X196	GS-NEM	(5,832.67)	0.00%	81,941.29	3,952.44	20.73	0.000
X197	MPE	(7,115.58)	0.00%	234,603.26	4,471.67	52.46	0.000
X198	MPE	(169,140.02)	0.01%	5,813,498.12	125,488.52	46.33	0.003
X310	GS DOS	(4,651.90)	0.00%	8,466.58	306.02	27.67	0.000
X320	LGS-1 DOS	(130,041.25)	0.00%	656,478.68	26,035.39	25.21	0.001
X324	LGS-2P DOS	(60,516.94)	0.00%	1,333,165.79	60,516.94	22.03	0.000
X325	LGS-2S DOS	(608,099.89)	0.02%	9,307,549.62	399,740.42	23.28	0.005
X327	LGS-3P DOS	(8,995,529.10)	0.31%	153,444,230.43	6,647,134.11	23.08	0.072
X328	LGS-3S DOS	(783,656.39)	0.03%	11,506,198.51	479,413.28	24.00	0.007
X329	LGS-3T DOS	(1,751,215.33)	0.06%	45,068,116.00	1,583,433.28	28.46	0.017
X350	LGS-XP DOS	(3,054,372.39)	0.11%	79,120,299.73	2,826,919.72	27.99	0.030
X351	LGS-XS DOS	(76,839.55)	0.00%	1,623,316.08	71,950.18	22.56	0.001
X352	LGS-XT DOS	(651,747.95)	0.02%	21,258,586.13	601,349.70	35.35	0.008
X364	LGS-2S-WP DOS	(15,093.17)	0.00%	365,671.23	13,141.15	27.83	0.000
X365	LGS-2T-WP DOS	(19,415.75)	0.00%	541,829.62	19,415.75	27.91	0.000
X366	LGS-3P-WP DOS	(362,070.98)	0.01%	9,354,520.03	333,693.52	28.03	0.004
X367	LGS-3S-WP DOS	(111,362.32)	0.00%	2,906,875.80	102,973.63	28.23	0.001
X368	LGS-3T-WP DOS	(136,825.38)	0.00%	3,804,018.80	136,825.38	27.80	0.001
Y001	RS-NEM	(9,640,396.69)	0.33%	6,523,658.07	290,026.93	22.49	0.075
Y002	RS-NEM	(8,747,584.25)	0.30%	5,565,486.39	262,271.22	21.22	0.064
Y003	RS-NEM	(34,001,035.96)	1.18%	4,753,776.00	208,384.75	22.81	0.269
Y016	RM-NEM	(41,694.23)	0.00%	617,683.67	23,177.61	26.65	0.000
Y017	RM-NEM	(51,005.98)	0.00%	761,520.53	39,225.07	19.41	0.000
Y018	RM-NEM	(315,950.16)	0.01%	1,921,668.46	75,126.04	25.58	0.003
Y022	LRS-NEM	(1,538.03)	0.00%	11,628.28	1,610.53	7.22	0.000
Y023	LRS-NEM	(4,693.71)	0.00%	80,805.78	4,210.81	19.19	0.000
Y024	LRS-NEM	(24,139.65)	0.00%	393,017.77	16,746.40	23.47	0.000
Y025	ORS-NEM	(77,058.74)	0.00%	547,945.18	32,369.48	16.93	0.000
Y026	ORS-NEM	(65,953.74)	0.00%	639,469.89	26,243.79	24.37	0.001
Y027	ORS-NEM	(275,458.83)	0.01%	1,368,601.99	79,321.57	17.25	0.002
Y028	ORS-NEM EVRR	(223,357.96)	0.01%	2,762,553.05	124,646.83	22.16	0.002
Y029	ORS-NEM EVRR	(229,327.84)	0.01%	2,188,508.64	101,781.45	21.50	0.002
Y030	ORS-NEM EVRR	(1,298,598.32)	0.04%	5,087,299.77	234,745.07	21.67	0.010
Y033	ORM-NEM	(554.39)	0.00%	17,502.49	555.70	31.50	0.000
Y034	ORM-NEM EVRR	(2,598.54)	0.00%	51,882.87	2,226.96	23.30	0.000
Y035	ORM-NEM EVRR	53.41	0.00%	2,643.87	86.37	30.61	(0.000)
Y036	ORM-NEM EVRR	(1,354.60)	0.00%	24,969.10	1,347.56	18.53	0.000
Y088	GS-NEM	(2,405.87)	0.00%	42,473.34	2,284.06	18.60	0.000
Y089	GS-NEM	(5,433.36)	0.00%	102,878.04	4,571.61	22.50	0.000
Y090	GS-NEM	(21,459.37)	0.00%	276,408.29	11,928.55	23.17	0.000
Y100	ORS-TOU	(3,567,629.34)	0.12%	6,957,508.81	397,094.94	17.52	0.022
Y101	ORS-TOU EVRR	(10,658,745.03)	0.37%	14,306,380.17	682,346.54	20.97	0.077
Y102	ORM-TOU	(206,888.84)	0.01%	1,321,946.33	74,142.15	17.83	0.001
Y103	ORM-TOU EVRR	(304,014.53)	0.01%	2,694,140.01	125,232.55	21.51	0.002
Y105	OLRS-TOU EVRR	(45,501.56)	0.00%	895,125.21	39,437.76	22.70	0.000
Y106	ORS-NEM	(379,010.28)	0.01%	1,640,696.22	93,853.15	17.48	0.002
Y107	ORS-NEM EVRR	(527,734.71)	0.02%	3,976,666.38	194,901.93	20.40	0.004
Y112	ORS-NEM	(93,892.72)	0.00%	1,079,105.98	44,570.97	24.21	0.001
Y113	ORS-NEM EVRR	(302,333.82)	0.01%	2,681,288.89	131,039.10	20.46	0.002
Y118	ORS-TOU CPP	(35,171.22)	0.00%	1,424,474.04	18,718.88	76.10	0.001
Y192	ORS-NEM EVRR	(9,443.53)	0.00%	174,425.01	9,189.61	18.98	0.000

Nevada Power Company d/b/a NV Energy **Schedule I**
Revenue Lag Days Lead Lag Study
October 1, 2023 - September 30,2024

R/S Count: 139

Weighted Avg Lag	23.51
Midpoint	15.21
Total Lag Days:	38.72

Activity Code	Rate Schedule	Revenue	Rev %	Dollar Days	ARAPPL	Avg Lag Days	Weighted Avg Lag
Y212	RS	(1,291,356.26)	0.04%	6,593,980.94	289,856.63	22.75	0.010
Y213	RM	(788,581.88)	0.03%	4,198,119.66	225,119.89	18.65	0.005
Y222	LRS	(12,697.86)	0.00%	263,719.24	12,110.73	21.78	0.000
Y227	RS-FLEX	(35,733.80)	0.00%	(238,733.07)	30,187.23	(7.91)	(0.000)
Y228	RM-FLEX	(21,862.03)	0.00%	(158,339.05)	18,904.80	(8.38)	(0.000)
Y230	ORS-TOU	(26,177.64)	0.00%	613,630.63	24,068.38	25.50	0.000
Y231	ORS-TOU EVRR	(60,066.29)	0.00%	1,246,754.11	56,449.60	22.09	0.000
Y232	ORM-TOU	(8,229.04)	0.00%	138,715.35	6,048.90	22.93	0.000
Y233	ORM-TOU EVRR	(15,728.24)	0.00%	292,159.22	14,144.60	20.66	0.000
Y241	ORM-TOU DDP	(973.87)	0.00%	21,854.99	973.87	22.44	0.000
Y251	RS	(5,121,672.78)	0.18%	7,065,139.18	372,183.84	18.98	0.034
Y252	RM	(1,400,949.16)	0.05%	1,682,529.56	168,575.21	9.98	0.005
Y266	RS-FLEX	(155,790.26)	0.01%	505,425.29	46,507.87	10.87	0.001
Y267	RM-FLEX	(53,399.45)	0.00%	386,524.24	15,472.20	24.98	0.000
Y269	ORS-TOU	(41,060.69)	0.00%	626,289.87	34,551.00	18.13	0.000
Y270	ORS-TOU EVRR	(60,120.40)	0.00%	937,027.90	54,659.51	17.14	0.000
Y271	ORM-TOU	(8,051.52)	0.00%	(149,974.83)	7,774.18	(19.29)	(0.000)
Y272	ORM-TOU EVRR	(4,316.09)	0.00%	63,187.64	3,952.32	15.99	0.000
Y701	LGS-1 NEM	(23,344.46)	0.00%	408,690.86	22,424.53	18.23	0.000
Y702	LGS-1 NEM	(105,413.00)	0.00%	1,657,505.57	97,614.32	16.98	0.001
Y703	LGS-1 NEM	(75,093.09)	0.00%	1,483,508.38	65,948.41	22.49	0.001
Y705	GS	(87,155.53)	0.00%	847,445.74	39,845.12	21.27	0.001
Y709	MPE	(70,904.64)	0.00%	1,263,315.50	74,901.12	16.87	0.000
Y710	LGS-1	(218,124.84)	0.01%	2,903,289.33	126,242.96	23.00	0.002
Y920	LGS-2S EVCCR	(2,305,311.38)	0.08%	50,544,576.14	2,225,430.64	22.71	0.018
Y928	MPE	(6,417,966.78)	0.22%	133,844,181.89	6,327,068.04	21.15	0.047
Y930	MPE	(28,958,068.87)	1.00%	881,131,974.01	30,500,136.54	28.89	0.290
Excluded[1]		(3,164,275.40)	100%				
		(2,889,108,113.56)					23.51

(1) Certain rate schedules were closed during 2024, and they were excluded from the calculation. They represent 0.11% of total revenue.

Nevada Power Company d/b/a NV Energy
Natural Gas - Summary of Expense Lead Days
October 1, 2023 - September 30,2024

Schedule IV
Lead Lag Study

	Payment Amount		Dollar Days
Natural Gas Purchases	431,865,139		10,830,434,048
Hedge Contract Settlements	-		-
Transportation	60,025,716		1,294,642,792
Total	491,890,855		12,125,076,841
		Lead Days	24.65
		Mid Month	15.21
		Total Lead Days	39.86

Nevada Power Company d/b/a NV Energy
Purchased Power - Summary of Expense Lead Days
October 1, 2023 - September 30,2024

Schedule V
Lead Lag Study

		Payment Amount			Dollar Days
Purchased Power	$	1,004,284,200.44		$	20,188,482,882.41
Prepaid Transmission		-			-
Energy Imbalance Market (EIM)		4,819,850.60			43,962,011.29
Steam from Other Resources		127,708.79			2,389,623.56
Total	$	1,009,231,759.83		$	20,234,834,517.26
			Lead Days		20.05
			Mid Month		15.21
			Total Lead Days		35.26

Nevada Power Company d/b/a NV Energy
Goods and Services
October 1, 2023 - September 30,2024

Schedule VI
Lead Lag Study

Total Amount Paid	Total Dollar Days
$ 1,344,293.85	$ 48,083,657.30

Total Lead Days: 35.77

Unit	Voucher	Vendor	Name	Service Date 1	Service Date 2	Invoice Date	Acctg Date	Payment Date	Lead Days	Amount Paid	Dollar Days

[redacted]

Nevada Power Company d/b/a NV Energy
Goods and Services
October 1, 2023 - September 30,2024

Schedule VI
Lead Lag Study

Total Amount Paid	Total Dollar Days
$ 1,344,293.85	$ 48,083,657.30

Total Lead Days: 35.77

Unit	Voucher	Vendor	Name	Service Date 1	Service Date 2	Invoice Date	Acctg Date	Payment Date	Lead Days	Amount Paid	Dollar Days

[redacted]

Nevada Power Company d/b/a NV Energy
Goods and Services
October 1, 2023 - September 30,2024

Schedule VI
Lead Lag Study

Total Amount Paid	Total Dollar Days
$ 1,344,293.85	$ 48,083,657.30

Total Lead Days: 35.77

Unit	Voucher	Vendor	Name	Service Date 1	Service Date 2	Invoice Date	Acctg Date	Payment Date	Lead Days	Amount Paid	Dollar Days

[redacted]

Nevada Power Company d/b/a NV Energy
Goods and Services
October 1, 2023 - September 30,2024

Schedule VI
Lead Lag Study

Total Amount Paid	Total Dollar Days
$ 1,344,293.85	$ 48,083,657.30

Total Lead Days: 35.77

Unit	Voucher	Vendor	Name	Service Date 1	Service Date 2	Invoice Date	Acctg Date	Payment Date	Lead Days	Amount Paid	Dollar Days

[redacted]

Nevada Power Company d/b/a NV Energy
Goods and Services
October 1, 2023 - September 30,2024

Schedule VI
Lead Lag Study

Total Amount Paid	Total Dollar Days
$ 1,344,293.85	$ 48,083,657.30

Total Lead Days: 35.77

Unit	Voucher	Vendor	Name	Service Date 1	Service Date 2	Invoice Date	Acctg Date	Payment Date	Lead Days	Amount Paid	Dollar Days

[redacted]

Nevada Power Company d/b/a NV Energy
Goods and Services
October 1, 2023 - September 30,2024

Schedule VI
Lead Lag Study

Total Amount Paid	Total Dollar Days
$ 1,344,293.85	$ 48,083,657.30

Total Lead Days: 35.77

Unit	Voucher	Vendor	Name	Service Date 1	Service Date 2	Invoice Date	Acctg Date	Payment Date	Lead Days	Amount Paid	Dollar Days

[redacted]

Nevada Power Company d/b/a NV Energy | **Schedule VII**
Labor Lead Days | Lead Lag Study
October 1, 2023 - September 30,2024

	Amount	% of Gross	Method of Payment	Pay Period	Payment Date	Total Lead Days	Weighted Lead Days
Total Gross Payroll	$ 219,559,095						
STIP [1] (per combined payroll report)	12,943,787			7	4	-	-
Vacation[1] (per combined payroll report)	16,656,081			7	4	-	-
Detailed Deductions:							
Garnishments	259,367	0.8%	A/P Check After Payroll/Direct Deposit	-	-	-	-
401K Loan1 MPAT SPP/NPC	581,237	1.7%	Wire Transfer After Payroll	7	4	11	0.03
401K Loan2 MPAT SPP/NPC	461,576	1.3%	Wire Transfer After Payroll	7	4	11	0.02
401K Loan3 MPAT SPP	309,882	0.9%	Wire Transfer After Payroll	7	4	11	0.02
Voluntary Hosp Ded-L396	16,536	0.0%	Wire Transfer Monthly	7	4	11	-
Medical - IBEW396	2,589,618	7.5%	Wire Transfer Trust Funds Monthly	15	4	19	0.23
Medical - MPAT	2,152,646	6.2%	Wire Transfer Trust Funds Monthly	15	4	19	0.19
HLI Credit	(560,950)	-1.6%	Wire Transfer Monthly	-	-	-	-
Voluntary Hospital Deductions	47,506	0.1%	Wire Transfer Monthly	15	4	19	-
401K Loan1 BU NPC	1,112,695	3.2%	Wire Transfer Monthly	15	4	19	0.10
401K Loan2 BU NPC	873,248	2.5%	Wire Transfer Monthly	15	4	19	0.08
Dental - MPAT	318,262	0.9%	Wire Transfer Trust Funds Monthly	15	4	19	0.03
Supplemental Life L396	425,365	1.2%	Wire Transfer Monthly	15	4	19	0.04
Supplemental Life MPAT/L1245	386,162	1.1%	Wire Transfer Monthly	15	4	19	0.03
Child Life MPAT/L1245	1,140	0.0%	Wire Transfer Monthly	15	4	19	-
Spouse Life MPAT/L1245	71,031	0.2%	Wire Transfer Monthly	15	4	19	0.01
Child Life L396	1,400	0.0%	Wire Transfer Monthly	15	4	19	-
Spouse Life L396	66,021	0.2%	Wire Transfer Monthly	15	4	19	0.01
Supplemental Life MPAT Exe	13,140	0.0%	Wire Transfer Monthly	15	4	19	-
Spouse Life MPAT Exe	1,222	0.0%	Wire Transfer Monthly	15	4	19	-
Child Life MPAT Exe	30	0.0%	Wire Transfer Monthly	15	4	19	-
Supp AD&D-L396	11,156	0.0%	Wire Transfer Monthly	15	4	19	-
Supplemental AD&D	39,331	0.1%	Wire Transfer Monthly	15	4	19	-
Long Term Disability IBEW396	387,682	1.1%	Wire Transfer Monthly	15	4	19	0.03
Vision - MPAT	61,631	0.2%	Wire Transfer Trust Funds Monthly	15	4	19	0.01
Tuition Payback	4,558	0.0%	A/P Check After Payroll	-	-	-	-
Health Savings Account EE	1,539,438	4.5%	Wire Transfer After Payroll	7	4	11	0.08
NVE PAC	26,081	0.1%	A/P Check After Payroll	7	4	11	-
Dependent Care FSA	66,884	0.2%	Wire Transfer After Payroll	7	4	11	-
FSA Dependent Care IBEW 396	24,241	0.1%	Wire Transfer Monthly	15	4	19	-
FSA Health Care	142,643	0.4%	Wire Transfer Monthly	15	4	19	0.01
FSA Health Care IBEW 396	62,355	0.2%	Wire Transfer Monthly	15	4	19	0.01
IBEW396 1.75 x hrly rate + $0	18,664	0.1%	Wire Transfer Monthly	15	4	19	-
IBEW396 BA Member	494,650	1.4%	Wire Transfer Monthly	15	4	19	0.04
IBEW396 A Member	351,068	1.0%	Wire Transfer Monthly	15	4	19	0.03
UWay - Flat Amt - All PPE	298,322	0.9%	A/P Check After Payroll	7	4	11	0.01
UWay - Flat Amt - 1st PPE	8,062	0.0%	A/P Check After Payroll	7	4	11	-
Credit Union NPC	1,378,058	4.0%	Wire Transfer After Payroll	7	4	11	0.07
Credit Union SPPC	31,375	0.1%	Wire Transfer After Payroll	7	4	11	-
401K Post - IBEW396	1,482,672	4.3%	Wire Transfer After Payroll	7	4	11	0.07
401K Post - MPAT	364,197	1.1%	Wire Transfer Trust Funds Monthly	15	4	19	0.03
401(k) Contribution	18,406,923	53.3%	Wire Transfer Monthly	15	4	19	1.61
Metlife Products	159,429	0.5%	A/P Check After Payroll	7	4	11	0.01
MetLife Products-L396	2,398	0.0%	A/P Check After Payroll	7	4	11	-
Metlife Pet	5,263	0.0%	A/P Check After Payroll (not used)	7	4	11	-
MetLife Pet-L396	3,929	0.0%	Wire Transfer After Payroll	7	4	11	-
Life Acct MPAT Exe	600	0.0%	Wire Transfer After Payroll	7	4	11	-
Nev Prepaid Tuition	9,312	0.0%	A/P Check Monthly	15	4	19	-
MetLife Legal Assistance-L396	10,662	0.0%	Wire Transfer After Payroll	7	4	11	-
Metlife Legal Assistance	34,492	0.1%	Wire Transfer After Payroll	7	4	11	-
Total Deductions	34,553,214	100.0%					2.80
Detailed Taxes:							
OASDI-EE	11,746,451	26.7%	Wire transfer	7	4	11	0.59
Medicare EE	3,081,622	7.0%	Wire transfer	7	4	11	0.15
Federal/State Withholding	29,086,411	66.2%	Wire transfer	7	4	11	1.46
Total Employee Taxes	43,914,485	100.0%					2.20
Net Payroll (excluding STIP & vacation listed above)	111,491,529			7	4	11	5.59
Total Gross Payroll	$ 219,559,095						10.59

[1] *Note: STIP and vacation are treated as an Other Deductions to rate base.*

Nevada Power Company d/b/a NV Energy | **Schedule VIII**
Mill Tax | Lead Lag Study
October 1, 2023 - September 30,2024

Accrual Period							Julian Dates				
From	To	Mill Tax Accrued	Payment Amount	Payment Date	Lead Days	Dollar Days	Payment	End of Period	Diff	Midpoint	Lead Days
10/01/23	10/31/23	646,131	646,131	04/01/24	168.5	$ 108,873,073.50	24092	23304	153	15.5	168.5
11/01/23	11/30/23	646,131	646,131	04/01/24	138.5	89,489,143.50	24092	23334	123	15.5	138.5
12/01/23	12/31/23	646,131	646,131	04/01/24	107.5	69,459,082.50	24092	23365	92	15.5	107.5
01/01/24	01/31/24	849,815	849,815	07/01/24	167.5	142,343,984.58	24183	24031	152	15.5	167.5
02/01/24	02/29/24	849,815	849,815	07/01/24	137.5	116,849,539.58	24183	24060	123	14.5	137.5
03/01/24	03/31/24	849,815	849,815	07/01/24	107.5	91,355,094.58	24183	24091	92	15.5	107.5
04/01/24	04/30/24	849,815	849,815	10/01/24	169.0	143,618,706.83	24275	24121	154	15.0	169.0
05/01/24	05/31/24	849,815	849,815	10/01/24	138.5	117,699,354.42	24275	24152	123	15.5	138.5
06/01/24	06/30/24	849,815	849,815	10/01/24	108.0	91,780,002.00	24275	24182	93	15.0	108.0
07/01/24	07/31/24	849,815	849,815	01/01/25	169.5	144,043,614.25	25001	24213	154	15.5	169.5
08/01/24	08/31/24	849,815	849,815	01/01/25	138.5	117,699,354.42	25001	24244	123	15.5	138.5
09/01/24	09/30/24	849,815	849,815	01/01/25	108.0	91,780,002.00	25001	24274	93	15.0	108.0
			9,586,727			$ 1,324,990,952.16					
					Lead Days	138.21					

Nevada Power Company d/b/a NV Energy
Possessory Interest Tax
October 1, 2023 - September 30,2024

Schedule IX(b)
Lead Lag Study

Accrual Period		Possessory					Julian Dates				
From	To	Interest Tax Accrued	Payment Amount	Payment Date	Lead Days	Dollar Days	Payment	End of Period	Diff	Midpoint	Lead Days
10/01/23	10/31/23	44	44	11/01/23	16.50	$ 731.70	23305	23304	1	15.5	16.5
11/01/23	11/30/23	44	44	11/01/23	(13.50)	(598.66)	23305	23334	(29)	15.5	(13.5)
12/01/23	12/31/23	44	44	11/01/23	(44.50)	(1,973.37)	23305	23365	(60)	15.5	(44.5)
01/01/24	01/31/24	18	18	11/01/24	290.50	5,210.89	24306	24031	275	15.5	290.5
02/01/24	02/29/24	18	18	11/01/24	260.50	4,672.76	24306	24060	246	14.5	260.5
03/01/24	03/31/24	18	18	11/01/24	230.50	4,134.63	24306	24091	215	15.5	230.5
04/01/24	04/30/24	18	18	11/01/24	200.00	3,587.53	24306	24121	185	15.0	200.0
05/01/24	05/31/24	18	18	11/01/24	169.50	3,040.43	24306	24152	154	15.5	169.5
06/01/24	06/30/24	18	18	11/01/24	139.00	2,493.34	24306	24182	124	15.0	139.0
07/01/24	07/31/24	18	18	11/01/24	108.50	1,946.24	24306	24213	93	15.5	108.5
08/01/24	08/31/24	18	18	11/01/24	77.50	1,390.17	24306	24244	62	15.5	77.5
09/01/24	09/30/24	18	18	11/01/24	47.00	843.07	24306	24274	32	15.0	47.0
			294			$ 25,478.73					
					Lead Days	86.52					

Nevada Power Company d/b/a NV Energy
Nevada use Tax On P Card Purchases
October 1, 2023 - September 30,2024

Schedule X
Lead Lag Study

Accrual Period		Use Tax on					Julian Dates				
From	To	P Cards Accrued	Payment Amount	Payment Date	Lead Days	Dollar Days	Payment	End of Period	Diff	Midpoint	Lead Days
10/01/23	10/31/23	1,306	1,306	10/31/23	15.5	$ 20,239.90	23304	23304	-	15.5	15.5
11/01/23	11/30/23	2,223	2,223	11/30/23	15.5	34,450.92	23334	23334	-	15.5	15.5
12/01/23	12/31/23	2,708	2,708	12/31/23	15.5	41,975.86	23365	23365	-	15.5	15.5
01/01/24	01/31/24	2,115	2,115	01/31/24	15.5	32,785.91	24031	24031	-	15.5	15.5
02/01/24	02/29/24	2,107	2,107	02/29/24	14.5	30,549.62	24060	24060	-	14.5	14.5
03/01/24	03/31/24	1,777	1,777	03/31/24	15.5	27,544.59	24091	24091	-	15.5	15.5
04/01/24	04/30/24	1,162	1,162	04/30/24	15.0	17,422.80	24121	24121	-	15.0	15.0
05/01/24	05/31/24	1,062	1,062	05/31/24	15.5	16,462.24	24152	24152	-	15.5	15.5
06/01/24	06/30/24	1,166	1,166	06/30/24	15.0	17,489.85	24182	24182	-	15.0	15.0
07/01/24	07/31/24	1,544	1,544	07/31/24	15.5	23,930.45	24213	24213	-	15.5	15.5
08/01/24	08/31/24	2,902	2,902	08/31/24	15.5	44,985.96	24244	24244	-	15.5	15.5
09/01/24	09/30/24	2,509	2,509	09/30/24	15.0	37,641.00	24274	24274	-	15.0	15.0
			22,581			$ 345,479.10					
					Lead Days	15.30					

Nevada Power Company d/b/a NV Energy
Arizona Property Taxes
October 1, 2023 - September 30,2024

Schedule XI
Lead Lag Study

Accrual Period							Julian Dates				
From	To	Nevada Property Tax	Payment Amount	Payment Date	Lead Days	Dollar Days	Payment	End of Period	Diff	Midpoint	Lead Days
10/01/23	10/31/23	4,985	4,985	04/30/24	197.5	$ 984,505.90	24121	23304	182	15.5	197.5
11/01/23	11/30/23	4,985	4,985	04/30/24	167.5	834,960.70	24121	23334	152	15.5	167.5
12/01/23	12/31/23	4,985	4,985	04/30/24	136.5	680,430.66	24121	23365	121	15.5	136.5
01/01/24	01/31/24	4,985	4,985	10/30/24	288.5	1,438,126.34	24304	24031	273	15.5	288.5
02/01/24	02/29/24	4,985	4,985	10/30/24	258.5	1,288,581.14	24304	24060	244	14.5	258.5
03/01/24	03/31/24	4,985	4,985	10/30/24	228.5	1,139,035.94	24304	24091	213	15.5	228.5
04/01/24	04/30/24	4,985	4,985	10/30/24	198.0	986,998.32	24304	24121	183	15.0	198.0
05/01/24	05/31/24	4,985	4,985	10/30/24	167.5	834,960.70	24304	24152	152	15.5	167.5
06/01/24	06/30/24	4,985	4,985	10/30/24	137.0	682,923.08	24304	24182	122	15.0	137.0
07/01/24	07/31/24	4,985	4,985	04/30/25	288.5	1,438,126.34	25120	24213	273	15.5	288.5
08/01/24	08/31/24	4,985	4,985	04/30/25	257.5	1,283,596.30	25120	24244	242	15.5	257.5
09/01/24	09/30/24	4,985	4,985	04/30/25	227.0	1,131,558.68	25120	24274	212	15.0	227.0
			59,818			$ 12,723,804.10					
					Lead Days	212.71					

Nevada Power Company d/b/a NV Energy
Nevada Unemployment Tax - Company Portion
October 1, 2023 - September 30,2024

Schedule XII
Lead Lag Study

Accrual Period						Julian Dates				
From	To	Number of Days	Midpoint	Payment Date	Lead Days	Payment	End of Period	Diff	Midpoint	Lead Days
10/01/23	12/31/23	92	46.0	01/31/24	77.0	24031	23365	31	46.0	77.0
01/01/24	03/31/24	90	45.0	04/30/24	75.0	24121	24091	30	45.0	75.0
04/01/24	06/30/24	91	45.5	07/31/24	76.5	24213	24182	31	45.5	76.5
07/01/24	09/30/24	92	46.0	10/31/24	77.0	24305	24274	31	46.0	77.0

Average Lead Days 76.38

Payment due the last business day of the month following the end of the quarter.

Nevada Power Company d/b/a NV Energy
Modified Business Tax (MBT)
October 1, 2023 - September 30,2024

Schedule XIII
Lead Lag Study

Accrual Period		Business					Julian Dates				
From	To	Tax Accrued	Payment Amount	Payment Date	Lead Days	Dollar Days	Payment	End of Period	Diff	Midpoint	Lead Days
10/01/23	10/31/23	-	-	01/31/24	107.5	$ -	24031	23304	92	15.5	107.5
11/01/23	11/30/23	-	-	01/31/24	77.5	-	24031	23334	62	15.5	77.5
12/01/23	12/31/23	-	-	01/31/24	46.5	-	24031	23365	31	15.5	46.5
01/01/24	01/31/24	-	-	04/30/24	105.5	-	24121	24031	90	15.5	105.5
02/01/24	02/29/24	-	-	04/30/24	75.5	-	24121	24060	61	14.5	75.5
03/01/24	03/31/24	-	-	04/30/24	45.5	-	24121	24091	30	15.5	45.5
04/01/24	04/30/24	-	-	07/09/24	85.0	-	24191	24121	70	15.0	85.0
05/01/24	05/31/24	64,745	64,745	07/09/24	54.5	3,528,619.40	24191	24152	39	15.5	54.5
06/01/24	06/30/24	90,632	90,632	07/09/24	24.0	2,175,158.16	24191	24182	9	15.0	24.0
07/01/24	07/31/24	-	-	10/31/24	107.5	-	24305	24213	92	15.5	107.5
08/01/24	08/31/24	-	-	10/31/24	76.5	-	24305	24244	61	15.5	76.5
09/01/24	09/30/24	-	-	10/31/24	46.0	-	24305	24274	31	15.0	46.0
			155,377			$ 5,703,777.56					
					Lead Days	36.71					

Nevada Power Company d/b/a NV Energy
FICA
October 1, 2023 - September 30,2024

Schedule XIV
Lead Lag Study

Pay Period	Payment Date	Total Lead Days
7.0	4.0	11.0

Nevada Power Company d/b/a NV Energy
Franchise Tax Nevada Counties
October 1, 2023 - September 30,2024

Schedule XV
Lead Lag Study

Accrual Period							Julian Dates				
From	To	Nev Franchise Tax Accrued	Payment Amount	Payment Date	Days	Dollar Days	Payment	End of Period	Diff	Midpoint	Days
10/01/23	10/31/23	197,956	197,956	06/06/24	234.5	$ 46,420,749.42	24158	23304	219	15.5	234.5
11/01/23	11/30/23	197,956	197,956	06/06/24	204.5	40,482,060.79	24158	23334	189	15.5	204.5
12/01/23	12/31/23	197,956	197,956	06/06/24	173.5	34,345,415.88	24158	23365	158	15.5	173.5
01/01/24	01/31/24	274,699	274,699	06/06/25	507.5	139,409,544.58	25157	24031	492	15.5	507.5
02/01/24	02/29/24	274,699	274,699	06/06/25	477.5	131,168,586.28	25157	24060	463	14.5	477.5
03/01/24	03/31/24	274,699	274,699	06/06/25	447.5	122,927,627.98	25157	24091	432	15.5	447.5
04/01/24	04/30/24	274,699	274,699	06/06/25	417.0	114,549,320.37	25157	24121	402	15.0	417.0
05/01/24	05/31/24	274,699	274,699	06/06/25	386.5	106,171,012.77	25157	24152	371	15.5	386.5
06/01/24	06/30/24	274,699	274,699	06/06/25	356.0	97,792,705.16	25157	24182	341	15.0	356.0
07/01/24	07/31/24	274,699	274,699	06/06/25	325.5	89,414,397.56	25157	24213	310	15.5	325.5
08/01/24	08/31/24	274,699	274,699	06/06/25	294.5	80,898,740.65	25157	24244	279	15.5	294.5
09/01/24	09/30/24	274,699	274,699	06/06/25	264.0	72,520,433.04	25157	24274	249	15.0	264.0
			3,066,156			$ 1,076,100,594.48					
					Lead Days	350.96					

Nevada Power Company d/b/a NV Energy
Federal Income Taxes
October 1, 2023 - September 30,2024

Schedule XVI
Lead Lag Study

Accrual Period		Number of		Payment	Julian Dates				Estimated	Weighted
From	To	Days	Midpoint	Date	Payment	12/31/2021	Diff	Lead Days	Percentage	Lead Days
10/01/23	12/31/23	91	45.6	12/15/23	23349	23365	(16)	29.63	25%	7.41
01/01/24	03/31/24	91	45.6	03/13/24	24073	24091	(18)	27.63	25%	6.91
04/01/24	06/30/24	91	45.6	06/13/24	24165	24182	(17)	28.63	25%	7.16
07/01/24	09/30/24	91	45.6	09/12/24	24256	24274	(18)	27.63	25%	6.91

Lead Days = Midpoint - (number of days - Julian date (payment)) — Lead Days: 28.39

Used the estimated quarterly payments and not the actual one payment in the final quarter that was actually made.

Nevada Power Company d/b/a NV Energy **Schedule XVII**
Long -Term Debt Lead Lag Study
October 1, 2023 - September 30,2024

	(a)	(b)	(c)	(d)	(e)	(f) = (b-a)/2	(g)=c-b+1	(h) = f+g	(i) = e / sum(e)	(j) = I * h
				($M)	($M)					
Descr	Fiscal Period Beginning	Fiscal Period Ending	Payment Date	Principal Amount	Amount	Service Lead	Payment Lead Days	Expense Lead Days	Weighting factor	Weighted Expense lead days
$370M G&R Series N	10/1/2023	9/30/2024	10/1/2023	$ 370.0	$ 12.2	182.50	(364.00)	(181.50)	7.2%	(12.99)
$500M G&R Series CC	10/1/2023	9/30/2024	11/1/2023	$ 500.0	$ 9.3	182.50	(333.00)	(150.50)	5.4%	(8.16)
$425M G&R Series DD	10/1/2023	9/30/2024	11/1/2023	$ 425.0	$ 5.1	182.50	(333.00)	(150.50)	3.0%	(4.50)
$400M G&R Series GG	10/1/2023	9/30/2024	11/1/2023	$ 400.0	$ 11.8	182.50	(333.00)	(150.50)	6.9%	(10.41)
$250M G&R Series Y	10/1/2023	9/30/2024	11/15/2023	$ 250.0	$ 6.8	182.50	(319.00)	(136.50)	4.0%	(5.45)
$40M Coconino 2017A	10/1/2023	9/30/2024	12/1/2023	$ 40.0	$ 0.8	182.50	(303.00)	(120.50)	0.5%	(0.58)
$13M Coconino 2017B	10/1/2023	9/30/2024	12/1/2023	$ 13.0	$ 0.2	182.50	(303.00)	(120.50)	0.1%	(0.17)
$39.5M Clark County 2017	10/1/2023	9/30/2024	12/1/2023	$ 39.5	$ 0.7	182.50	(303.00)	(120.50)	0.4%	(0.52)
$350M G&R Series R	10/1/2023	9/30/2024	1/1/2024	$ 350.0	$ 11.8	182.50	(272.00)	(89.50)	6.9%	(6.18)
$300M G&R Series EE	10/1/2023	9/30/2024	2/1/2024	$ 300.0	$ 4.7	182.50	(241.00)	(58.50)	2.7%	(1.61)
$250M G&R Series X	10/1/2023	9/30/2024	3/15/2024	$ 250.0	$ 6.7	182.50	(198.00)	(15.50)	3.9%	(0.61)
$500M G&R Series 2023A	10/1/2023	9/30/2024	3/15/2024	$ 500.0	$ 15.2	182.50	(198.00)	(15.50)	8.9%	(1.38)
$370M G&R Series N	10/1/2023	9/30/2024	4/1/2024	$ 370.0	$ 12.2	182.50	(181.00)	1.50	7.2%	0.11
$500M G&R Series CC	10/1/2023	9/30/2024	5/1/2024	$ 500.0	$ 9.3	182.50	(151.00)	31.50	5.4%	1.71
$425M G&R Series DD	10/1/2023	9/30/2024	5/1/2024	$ 425.0	$ 5.1	182.50	(151.00)	31.50	3.0%	0.94
$400M G&R Series GG	10/1/2023	9/30/2024	5/1/2024	$ 400.0	$ 11.8	182.50	(151.00)	31.50	6.9%	2.18
$250M G&R Series Y	10/1/2023	9/30/2024	5/15/2024	$ 250.0	$ 6.8	182.50	(137.00)	45.50	4.0%	1.82
$40M Coconino 2017A	10/1/2023	9/30/2024	6/1/2024	$ 40.0	$ 0.8	182.50	(120.00)	62.50	0.5%	0.30
$13M Coconino 2017B	10/1/2023	9/30/2024	6/1/2024	$ 13.0	$ 0.2	182.50	(120.00)	62.50	0.1%	0.09
$39.5M Clark County 2017	10/1/2023	9/30/2024	6/1/2024	$ 39.5	$ 0.7	182.50	(120.00)	62.50	0.4%	0.27
$350M G&R Series R	10/1/2023	9/30/2024	7/1/2024	$ 350.0	$ 11.8	182.50	(90.00)	92.50	6.9%	6.38
$300M G&R Series EE	10/1/2023	9/30/2024	8/1/2024	$ 300.0	$ 4.7	182.50	(59.00)	123.50	2.7%	3.39
$250M G&R Series X	10/1/2023	9/30/2024	9/15/2024	$ 250.0	$ 6.7	182.50	(14.00)	168.50	3.9%	6.63
$500M G&R Series 2023A	10/1/2023	9/30/2024	9/15/2024	$ 500.0	$ 15.2	182.50	(14.00)	168.50	8.9%	14.97
Total					**$ 170.7**		**24**		**100.0%**	**(13.75)**
Revolving credit advances (1)				8,333		30	15			0.04
				3,445,833				Total Lead Days		(13.71)

	Oct-23	$ -
	Nov-23	-
	Dec-23	-
	Jan-24	40,000
	Feb-24	-
	Mar-24	-
	Apr-24	60,000
	May-24	-
	Jun-24	-
	Jul-24	-
	Aug-24	-
	Sep-24	-
Average		$ 8,333

Nevada Power Company d/b/a NV Energy
Customer Deposits
October 1, 2023 - September 30,2024

Schedule XVIII
Lead Lag Study

Per Policy Calculation of the Customer Deposits Lead Days	
Days in the year (using 360 convention)	360
Divided by number of refunds per year	2
Divided by 2 to obtain midpoint of refund period	2
Lead Days - Annual Portion	90
Days in the month (using 360 convention)	30
Divided by 2 to obtain midpoint of refund period	2
Lead Days - Month Portion	15
Total Lead Days	105.00

Nevada Power Company d/b/a NV Energy
Commerce Tax
October 1, 2023 - September 30,2024

Schedule XIX
Lead Lag Study

Accrual Period		Business					Julian Dates				
From	To	Tax Accrued	Payment Amount	Payment Date	Lead Days	Dollar Days	Payment	End of Period	Diff	Midpoint	Lead Days
10/01/23	10/31/23	349,834	349,834	08/15/24	304.5	$ 106,524,316.38	24228	23304	289	15.5	304.5
11/01/23	11/30/23	349,834	349,834	08/15/24	274.0	95,854,393.07	24228	23334	259	15.0	274.0
12/01/23	12/31/23	349,834	349,834	08/15/24	243.5	85,184,469.75	24228	23365	228	15.5	243.5
01/01/24	01/31/24	349,834	349,834	08/15/24	212.5	74,339,629.66	24228	24031	197	15.5	212.5
02/01/24	02/29/24	349,834	349,834	08/15/24	182.5	63,844,623.12	24228	24060	168	14.5	182.5
03/01/24	03/31/24	349,834	349,834	08/15/24	152.5	53,349,616.58	24228	24091	137	15.5	152.5
04/01/24	04/30/24	349,834	349,834	08/15/24	122.0	42,679,693.26	24228	24121	107	15.0	122.0
05/01/24	05/31/24	349,834	349,834	08/15/24	91.5	32,009,769.95	24228	24152	76	15.5	91.5
06/01/24	06/30/24	349,834	349,834	08/15/24	61.0	21,339,846.63	24228	24182	46	15.0	61.0
07/01/24	07/31/24	349,834	349,834	08/15/25	395.5	138,359,169.55	25227	24213	380	15.5	395.5
08/01/24	08/31/24	349,834	349,834	08/15/25	364.5	127,514,329.46	25227	24244	349	15.5	364.5
09/01/24	09/30/24	349,834	349,834	08/15/25	334.0	116,844,406.15	25227	24274	319	15.0	334.0
			4,198,003			$ 957,844,263.56					
					Lead Days	228.17					

Nevada Power Company d/b/a NV Energy
Leases
October 1, 2023 - September 30,2024

Schedule XX
Lead Lag Study

Total Adjusted Amoun	Total Dollar Days
$ 42,201,872.14	$ (259,255,024.90)

Name	Total	Disallowance or allowed %	Adjusted Amount	Service Date 1	Service Date 2	Payment Date	Lead Days	Dollar Days
Altec Capital Leasing - Fleet	$ 298,691.18	241,939.86	$ 56,751.32	10/1/2023	10/31/2023	10/25/2023	9	$ 510,761.92
Altec Capital Leasing - Fleet	334,745.72	275,562.68	59,183.04	11/1/2023	11/30/2023	11/30/2023	15	858,154.13
Altec Capital Leasing - Fleet	292,666.65	240,132.99	52,533.66	12/1/2023	12/31/2023	12/27/2023	11	577,870.30
Altec Capital Leasing - Fleet	317,882.34	261,140.34	56,742.00	1/1/2024	1/31/2024	01/29/2024	13	737,645.97
Altec Capital Leasing - Fleet	310,324.60	244,815.08	65,509.52	2/1/2024	2/29/2024	02/27/2024	12	786,114.28
Altec Capital Leasing - Fleet	298,614.30	236,562.25	62,052.05	3/1/2024	3/31/2024	03/27/2024	11	682,572.57
Altec Capital Leasing - Fleet	337,228.54	282,192.84	55,035.70	4/1/2024	4/30/2024	04/26/2024	11	577,874.83
Altec Capital Leasing - Fleet	334,733.54	266,481.37	68,252.17	5/1/2024	5/31/2024	05/29/2024	13	887,278.19
Altec Capital Leasing - Fleet	343,545.31	273,359.00	70,186.31	6/1/2024	6/30/2024	06/26/2024	11	736,956.22
Altec Capital Leasing - Fleet	318,906.90	253,722.33	65,184.57	7/1/2024	7/31/2024	07/26/2024	10	651,845.70
Altec Capital Leasing - Fleet	370,211.91	316,975.44	53,236.47	8/1/2024	8/31/2024	08/27/2024	11	585,601.20
Altec Capital Leasing - Fleet	358,384.74	306,849.01	51,535.73	9/1/2024	9/30/2024	09/27/2024	12	592,660.84
Beltway	382,946.67	108,924.67	274,022.00	10/1/2023	10/31/2023	10/06/2023	(10)	(2,740,220.00)
Beltway	405,501.13	132,206.17	273,294.96	11/1/2023	11/30/2023	11/08/2023	(8)	(2,049,712.20)
Beltway	405,501.13	133,007.48	272,493.65	12/1/2023	12/31/2023	12/05/2023	(11)	(2,997,430.15)
Beltway	414,957.75	199,055.17	215,902.58	1/1/2024	1/31/2024	01/04/2024	(12)	(2,590,830.96)
Beltway	414,957.75	134,891.30	280,066.45	2/1/2024	2/29/2024	02/07/2024	(8)	(2,240,531.60)
Beltway	414,957.75	136,545.30	278,412.45	3/1/2024	3/31/2024	03/04/2024	(12)	(3,340,949.40)
Beltway	414,957.75	137,382.57	277,575.18	4/1/2024	4/30/2024	04/03/2024	(13)	(3,469,689.75)
Beltway	414,957.75	138,226.78	276,730.97	5/1/2024	5/31/2024	05/07/2024	(9)	(2,490,578.73)
Beltway	414,957.75	139,077.99	275,879.76	6/1/2024	6/30/2024	06/04/2024	(12)	(3,172,617.24)
Beltway	414,957.75	139,936.21	275,021.54	7/1/2024	7/31/2024	07/02/2024	(14)	(3,850,301.56)
Beltway	414,957.75	140,801.61	274,156.14	8/1/2024	8/31/2024	08/08/2024	(8)	(2,193,249.12)
Beltway	414,957.75	135,714.90	279,242.85	9/1/2024	9/30/2024	09/05/2024	(11)	(2,932,049.93)
Enterprise FM Exchange Inc - Fleet	78,464.48	64,591.96	13,872.52	10/1/2023	10/31/2023	11/03/2023	18	249,705.36
Enterprise FM Exchange Inc - Fleet	86,850.32	71,260.69	15,589.63	11/1/2023	11/30/2023	12/15/2023	30	459,894.16
Enterprise FM Exchange Inc - Fleet	84,685.39	69,569.05	15,116.34	12/1/2023	12/31/2023	01/04/2024	19	287,210.50
Enterprise FM Exchange Inc - Fleet	75,434.96	59,510.64	15,924.32	1/1/2024	1/31/2024	02/02/2024	17	270,713.44
Enterprise FM Exchange Inc - Fleet	66,098.44	52,363.18	13,735.26	2/1/2024	2/29/2024	03/04/2024	18	247,234.60
Enterprise FM Exchange Inc - Fleet	73,589.02	61,579.29	12,009.73	3/1/2024	3/31/2024	04/04/2024	19	228,184.83
Enterprise FM Exchange Inc - Fleet	65,590.55	52,216.64	13,373.91	4/1/2024	4/30/2024	05/03/2024	18	234,043.48
Enterprise FM Exchange Inc - Fleet	65,589.67	52,189.70	13,399.97	5/1/2024	5/31/2024	06/05/2024	20	267,999.39
Enterprise FM Exchange Inc - Fleet	53,088.13	42,236.92	10,851.21	6/1/2024	6/30/2024	06/24/2024	9	92,235.32
Enterprise FM Exchange Inc - Fleet	50,832.05	43,522.40	7,309.65	7/1/2024	7/31/2024	07/23/2024	7	51,167.54
Enterprise FM Exchange Inc - Fleet	46,831.37	40,097.02	6,734.35	8/1/2024	8/31/2024	08/20/2024	4	26,937.40
Enterprise FM Exchange Inc - Fleet	91,106.03	73,795.88	17,310.15	9/1/2024	9/30/2024	09/25/2024	10	164,446.38
Great Basin Transmission - Online	2,881,963.46	71,076.97	2,810,886.49	10/1/2023	10/31/2023	10/17/2023	1	2,810,886.49
Great Basin Transmission - Online	2,881,963.46	71,076.97	2,810,886.49	11/1/2023	11/30/2023	11/17/2023	2	4,216,329.74
Great Basin Transmission - Online	2,881,963.46	71,076.97	2,810,886.49	12/1/2023	12/31/2023	12/18/2023	2	5,621,772.98
Great Basin Transmission - Online	2,881,963.46	71,076.97	2,810,886.49	1/1/2024	1/31/2024	01/12/2024	(4)	(11,243,545.96)
Great Basin Transmission - Online	2,881,963.46	71,076.97	2,810,886.49	2/1/2024	2/29/2024	02/12/2024	(3)	(8,432,659.47)
Great Basin Transmission - Online	2,881,963.46	71,076.97	2,810,886.49	3/1/2024	3/31/2024	03/12/2024	(4)	(11,243,545.96)
Great Basin Transmission - Online	2,881,963.46	71,076.97	2,810,886.49	4/1/2024	4/30/2024	04/12/2024	(4)	(9,838,102.72)
Great Basin Transmission - Online	2,881,963.46	71,076.97	2,810,886.49	5/1/2024	5/31/2024	05/13/2024	(3)	(8,432,659.47)
Great Basin Transmission - Online	2,881,963.46	71,076.97	2,810,886.49	6/1/2024	6/30/2024	06/12/2024	(4)	(9,838,102.72)
Great Basin Transmission - Online	2,881,963.46	71,076.97	2,810,886.49	7/1/2024	7/31/2024	07/12/2024	(4)	(11,243,545.96)
Great Basin Transmission - Online	2,881,963.46	71,076.97	2,810,886.49	8/1/2024	8/31/2024	08/12/2024	(4)	(11,243,545.96)
Great Basin Transmission - Online	2,881,963.46	71,076.97	2,810,886.49	9/1/2024	9/30/2024	09/12/2024	(4)	(9,838,102.72)
Great Basin Transmission - Online Capital Repair	57,423.21		57,423.21	10/1/2023	10/31/2023	11/06/2023	21	1,202,699.61
Great Basin Transmission - Online Capital Repair	57,271.41		57,271.41	11/1/2023	11/30/2023	12/13/2023	28	1,574,962.13
Great Basin Transmission - Online Capital Repair	57,271.35		57,271.35	12/1/2023	12/31/2023	02/13/2024	59	3,239,330.69
Great Basin Transmission - Online Capital Repair	54,903.91		54,903.91	1/1/2024	1/31/2024	02/13/2024	28	3,194,429.84
Great Basin Transmission - Online Capital Repair	114,086.78		114,086.78	2/1/2024	2/29/2024	03/25/2024	39	6,286,112.82
Great Basin Transmission - Online Capital Repair	161,182.38		161,182.38	3/1/2024	3/31/2024	03/25/2024	9	595,594.89
Great Basin Transmission - Online Capital Repair	66,177.21		66,177.21	4/1/2024	4/30/2024	04/29/2024	14	897,507.41
Great Basin Transmission - Online Capital Repair	66,482.03		66,482.03	5/1/2024	5/31/2024	05/28/2024	12	795,554.28
Great Basin Transmission - Online Capital Repair	66,296.19		66,296.19	6/1/2024	6/30/2024	06/25/2024	10	608,777.48
Great Basin Transmission - Online Capital Repair	64,081.84		64,081.84	7/1/2024	7/31/2024	07/29/2024	13	830,730.29
Great Basin Transmission - Online Capital Repair	63,902.33		63,902.33	8/1/2024	8/31/2024	08/27/2024	11	860,706.99
Great Basin Transmission - Online Capital Repair	78,246.09		78,246.09	9/1/2024	9/30/2024	09/24/2024	9	665,091.77
KB Beltway MT LLC	7,699.50		7,699.50	10/1/2023	10/31/2023	10/25/2023	9	69,295.50
KB Beltway MT LLC	7,699.50		7,699.50	11/1/2023	11/30/2023	11/08/2023	(8)	(57,746.25)
KB Beltway MT LLC	7,699.50		7,699.50	12/1/2023	12/31/2023	12/04/2023	(12)	(92,394.00)
KB Beltway MT LLC	15,399.00		15,399.00	1/1/2024	2/29/2024	01/31/2024	1	7,699.50
KB Beltway MT LLC	15,868.80		15,868.80	3/1/2024	4/30/2024	04/05/2024	5	79,344.00
KB Beltway MT LLC	7,934.40		7,934.40	5/1/2024	5/31/2024	05/08/2024	(8)	(63,475.20)
KB Beltway MT LLC	7,934.40		7,934.40	6/1/2024	6/30/2024	06/05/2024	(11)	(83,311.20)
KB Beltway MT LLC	7,934.40		7,934.40	7/1/2024	7/31/2024	07/02/2024	(14)	(111,081.60)
KB Beltway MT LLC	7,934.40		7,934.40	8/1/2024	8/31/2024	08/09/2024	(7)	(55,540.80)
KB Beltway MT LLC	7,934.40		7,934.40	9/1/2024	9/30/2024	09/06/2024	(10)	(75,376.80)
Konica Minolta Business	11,352.03		11,352.03	10/1/2023	10/31/2023	12/08/2023	53	601,657.59
Konica Minolta Business	11,261.35		11,261.35	11/1/2023	11/30/2023	12/21/2023	36	399,777.93
Konica Minolta Business	10,625.72		10,625.72	12/1/2023	12/31/2023	01/29/2024	44	467,531.68
Konica Minolta Business	11,544.28		11,544.28	1/1/2024	1/31/2024	02/28/2024	43	496,404.04
Konica Minolta Business	11,278.50		11,278.50	2/1/2024	2/29/2024	03/29/2024	43	484,975.50
Konica Minolta Business	11,247.96		11,247.96	3/1/2024	3/31/2024	04/29/2024	44	494,910.24
Konica Minolta Business	11,256.11		11,256.11	4/1/2024	4/30/2024	05/29/2024	44	489,640.79
Konica Minolta Business	11,254.78		11,254.78	5/1/2024	5/31/2024	06/28/2024	43	483,955.54
Konica Minolta Business	11,258.73		11,258.73	6/1/2024	6/30/2024	07/29/2024	44	489,754.76
Konica Minolta Business	11,759.55		11,759.55	7/1/2024	7/31/2024	08/29/2024	44	517,420.20

Nevada Power Company d/b/a NV Energy
Leases
October 1, 2023 - September 30,2024

Schedule XX
Lead Lag Study

Total Adjusted Amoun	Total Dollar Days
$ 42,201,872.14	$ (259,255,024.90)

Name	Total	Disallowance or allowed %	Adjusted Amount	Service Date 1	Service Date 2	Payment Date	Lead Days	Dollar Days
Konica Minolta Business	11,574.71		11,574.71	8/1/2024	8/31/2024	09/30/2024	45	520,861.95
Konica Minolta Business	11,317.08		11,317.08	9/1/2024	9/30/2024	10/31/2024	46	514,927.14
Pacific Office Automation	15,699.89		15,699.89	10/1/2023	10/31/2023	11/08/2023	23	361,097.47
Pacific Office Automation	18,918.87		18,918.87	11/1/2023	11/30/2023	12/12/2023	27	501,350.06
Pacific Office Automation	17,751.67		17,751.67	12/1/2023	12/31/2023	01/10/2024	25	443,791.75
Pacific Office Automation	14,734.65		14,734.65	1/1/2024	1/31/2024	02/09/2024	24	353,631.60
Pacific Office Automation	17,156.67		17,156.67	2/1/2024	2/29/2024	03/08/2024	22	377,446.74
Pacific Office Automation	17,160.10		17,160.10	3/1/2024	3/31/2024	04/10/2024	25	429,002.50
Pacific Office Automation	19,394.76		19,394.76	4/1/2024	4/30/2024	05/10/2024	25	475,171.62
Pacific Office Automation	35,756.34		35,756.34	5/1/2024	5/31/2024	06/07/2024	22	786,639.48
Pacific Office Automation	16,850.14		16,850.14	6/1/2024	6/30/2024	07/10/2024	25	412,828.43
Pacific Office Automation	20,670.84		20,670.84	7/1/2024	7/31/2024	08/09/2024	24	496,100.16
Pacific Office Automation	9,988.53		9,988.53	8/1/2024	8/31/2024	10/01/2024	46	459,472.38
Pacific Office Automation	4,329.85		4,329.85	9/1/2024	9/30/2024	11/01/2024	47	201,338.03
Pearson	1,544,500.00		1,544,500.00	1/1/2024	6/30/2024	01/31/2024	(61)	(93,442,250.00)
Pearson	1,457,000.00		1,457,000.00	7/1/2024	12/31/2024	07/27/2024	(66)	(95,433,500.00)
	$ 48,613,232.48		$ 42,201,872.14					$ (259,255,024.90)
							Lead Days	(6.14)
							Total Lead Days	(6.14)

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AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, HAROLD WALKER, III, 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: February 14, 2025

Harold Walker, III

JEFFREY R. BOHRMAN

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 25-02____
2025 General Rate Case

Prepared Direct Testimony of

Jeffrey R. Bohrman

Rate Design

I. INTRODUCTION

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

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 leadership role 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 many times during my nearly 20 years with the Companies, including in Nevada Power's 2023 General Rate Case ("GRC") proceeding (Docket No. 23-06007). A complete list of dockets in which I have provided testimony before this Commission is included with my statement of qualifications.

4. Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY AND HOW IT IS ORGANIZED.

A. I support the Company's proposals with regard to cost of service and rate design in this GRC proceeding. My testimony supports and is supported by Company witnesses Samantha Prest, who sponsors the technical aspect of Nevada Power's rate proposal, Brittany Berg, who sponsors the Company's proposed cost of service model development, Hank Will, who sponsors the development and implementation plan of the proposed low income discount rate proposal, Jenny Naughton, who sponsors the regulatory asset treatment related to the proposed low income discount rate proposal, Joseph Esposito, who sponsors the development of hourly cost responsibility factors as well as the transmission and distribution unit investment costs which feed directly to the Company's cost of service models, and Kevin Branderhorst, who supports the proposed updates to Rule 9 (line extensions) and customer-specific facilities investment updates in this proceeding. In addition, Janet Wells sponsors the Company's present and proposed tariff exhibits and proposed tariff changes. Finally, Alison Williams from B Strategic Solutions, provides testimony in support of the Company's net energy metering ("NEM") related proposals in this GRC.

My testimony is organized as follows:

Section I. Introduction;

Section II. Cost of service studies;

Section III. Rate design recommendation and proposal;

Section IV. Low-income rate discount proposal;

Section V. Excess energy netting for new NEM customers proposal; and

Section VI. Recommendations and Conclusion.

5. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. I am sponsoring the following five exhibits.

Exhibit Bohrman Direct-1, Statement of Qualifications;

Exhibit Bohrman Direct-2, Marginal Cost of Service Study (informational);

Exhibit Bohrman Direct-3, Recent Cost of Service testimony reference list;

Exhibit Bohrman Direct-4, Brief regulatory history of NEM in Nevada from 2013 to present; and

Exhibit Bohrman Direct-5, NMR-2025 Tariff Redline.

II. COST OF SERVICE STUDIES

6. Q. WHY DOES NEVADA POWER FILE A COST OF SERVICE STUDY IN THE RATE DESIGN PHASE OF A GRC?

A. Importantly, there is a preference to provide a cost of service analysis with each GRC filing. Nevada Administrative Code ("NAC") 704.660 states, "[t]he Commission may consider a utility's marginal (incremental) cost of service to each class of customer in determining the revenue required from that class." The Company strongly agrees that any equitable rate design requires an objective cost of service study as the basis to inform just and reasonable rates and determine what may represent cross-subsidies among customer classes. This also is aligned with best practice in the industry. Cost of service studies are filed as the foundation of the Company's rate design proposals because in absence of such a study, the Commission, the Company, and any other interested parties to the proceeding would have no grounds to assess (and understand) the merits and equity impacts – both intended and unintended – of proposed and alternative rate design proposals.

7. Q. WHICH COST OF SERVICE MODEL PROVIDES THE STRONGEST INFORMATION ON WHICH TO BASE NEVADA POWER'S RATE DESIGN DECISION MAKING AND PROPOSALS?

A. As the Company has expressed in numerous preceding GRC dockets and investigations, the most accurate and defensible cost of service model to inform rate design is the Company's Marginal Cost of Service Study ("MCS"). The MCS calculates the cost impact of customer decisions, involving all functions of the utility's business. The study is consistent with the Company's planning and operational procedures, reflects the jointly dispatched nature of the integrated resources and transmission system, considers both the energy and demand-related cost implications from meeting and serving customer needs, and, as a result, is the best available model on which to base rate design decisions. Attached to my testimony is **Exhibit Bohrman Direct-2**, which is the full MCS that includes energy and is based upon the jointly dispatched system. The exhibit reflects methodologies that are consistent with previous MCS models filed with the Commission in GRC proceedings.

8. Q. WHAT COST STUDY IS THE BASIS FOR THE COMPANY'S COST ALLOCATION AND RATE DESIGN PROPOSAL IN THIS CASE?

A. The Company has heard the Commission in the past several cases and are responding to the stated preference for an alternative ECS from the previously proposed MCS. The Company acknowledges the Commission's stated preference in recent GRCs for an alternative cost of service study for cost allocation purposes.[1] The Company supports a rate design that follows the cost causation of customer classes informed by an Embedded Cost of Service Study ("ECS"), even though the Company continues to believe in the merits of the MCS. There are major differences when comparing the Commission's preferred ECS to the Company's MCS. Specifically, the Commission's ECS: (a) does not include all functions of the utility's business operations, and leaves out the energy-related function on the grounds that these costs are recovered outside of the Base Tariff General Rate ("BTGR"), ignoring the actual cost causation of these costs; and (b) relies upon a hypothetical Nevada Power-only, or stand-alone ("SAD"), scenario to dispatch the utility's system. This alternative ECS model varies somewhat from a historical view of an ECS, in that, at least, cost allocation relies on a set of marginal hourly cost responsibility factors. This sort of hybrid model has been approved as the basis for the Company's rate design in several past GRC proceedings. Ms. Berg supports the Company's proposed ECS. To not clutter this testimony with the repeated arguments that have been made in past cases, the attached **Exhibit Bohrman Direct-3** provides a non-inclusive list of citations to Company testimony from previous GRCs. The Company unequivocally continues to reassert its historical positions advocating for the MCS methodology as the soundest and most robust

[1] *See* Modified Final Orders in Sierra's 2024 GRC (Docket No. 24-02026 at paragraph 660), Nevada Power's 2023 GRC (Docket No. 23-06007 at paragraphs 671 and 672), and Sierra's 2022 GRC (Docket No. 22-06014 at paragraphs 735 and 736).

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conceptual methodology to deliver the most equitable and efficient cost allocation and rate design.

9. Q. IF THE COMPANY IS NOT BASING THE RATE DESIGN PROPOSAL ON THE MCS, WHY IS A VERSION OF THE MODEL BEING PROVIDED AS AN EXHIBIT TO YOUR TESTIMONY?

A. Aspects of the MCS are used throughout the Company for a variety of regulatory decisions, including, for example, determination of contract pricing offerings to large commercial users, evaluation of NEM impacts, Demand Side Management avoided capacity cost considerations, and generally ensuring that any policy initiatives serve their intended purposes well. Importantly, the MCS is being provided as an informational exhibit in this rate case because it is helpful to all parties both to measure alternative rate design proposals against and to be used as a reasonableness test when evaluating such proposals. The Company also relies on certain results of the MCS that are applied to the ECS to improve cost causation of the latter. For example, the Company relies on the MCS for the relative differentiation between distribution substation and lower voltage primary distribution, as well as the hourly cost responsibility factors. For these reasons, the Company considers an updated MCS model as crucial in maintaining relevant information on which to base decision-making for a variety of applications and pricing proposals throughout the year and to serve as a check against some of the results of an ECS that use otherwise more restrictive cost categorizations.

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10. Q. IS THE COMPANY PROVIDING THE MCS FOR ANY OTHER REASON BEYOND BEING AN INFORMATIONAL RESOURCE?

A. No. There is no specific request in this proceeding related to the MCS, **Exhibit Bohrman Direct-2**.

11. Q. DID THE COMPANY CONTEMPLATE FILING ANY ADDITIONAL COST OF SERVICE STUDIES IN THIS PROCEEDING?

A. Yes. Directive 11 from the Commission's Modified Final Order in Nevada Power's 2023 GRC (Docket No. 23-06007) stated that the Company "shall work with the Regulatory Operations Staff ["Staff'] to file an updated version of the Regulatory Operations Staff's cost-of-service study model ("Staff's Model"), excluding the energy component and with stand-alone dispatch." The Company met with Staff and had continuing dialogue in an attempt to rectify issues contained within the model. Unfortunately, at the time of this filing many of these issues are unresolved and as such the Company could not use Staff's Model to develop rates. Ms. Berg discusses this in more detail in her prepared direct testimony. The Company intends to continue this work with Staff in hopes of utilizing the model in the future if the issues are resolved and the model is able to inform rate design.

III. <u>RATE DESIGN PROPOSALS</u>

12. Q. PLEASE DESCRIBE THE COMPANY'S RATE DESIGN PROPOSALS.

A. The Company's primary rate design proposal for this filing implements rates reflecting the proposed $216 million sales revenue requirement increase. I am supporting the Company's proposal regarding:

- The implementation of a 1.25 percent capped class revenue mechanism for the single-family residential ("RS") customer class;

- The setting of the Basic Service Charge ("BSC") for all customer classes; and
- The proposal to implement a demand charge rate component for all residential and small commercial classes.

The proposed rate design is the result of multiple technical inputs supported by the Company's witnesses described above.

13. Q. PLEASE SUMMARIZE THE CONCEPT OF THE CAP MECHANISM, AND HOW THIS POLICY DECISION IS INCORPORATED INTO PROPOSED RATES.

A. The Company's rate design proposal follows the cost allocation by customer classes as informed by the ECS. Rates can be set above or below cost for classes to effectuate goals of the Commission or public policy set by the Legislature.

The cap is implemented in Statement O by proposing the percent change in class BTGR revenue for standard bundled customer classes. This is a deviation from prior rate design practice in which the rate design was based on both a customer's BTGR and Base Tariff Energy Rate ("BTER") revenue, combined. Because the Company is now proposing rate design based on a cost-of-service analysis consistent with past Commission orders that does not include energy, the impact being presented only reflects a portion of customer bills. The proposed cap implements a limit on the highest change that a class will experience on its electricity bill excluding BTER, taxes and surcharges. Any required revenue above the capped level will be shifted to other classes to ensure that the overall total revenue requirement is appropriately recovered through rates. In this case, the RS class percent change is proposed to equal the system average BTGR increase of

19.1 percent plus 1.25 percent. Practically, the 1.25 percent cap is set to shift all additional cost-based class revenue for the RS class above 20.35 percent (19.1 percent plus 1.25 percent cap in this filing) to the remaining customer classes. As discussed in the prepared direct testimony of Ms. Prest, the cost-based class revenue for the RS class is 26.7 percent higher than is currently being recovered through customer rates. This means that 6.4 percent of the increase that otherwise would have been allocated to the RS class is shifted to all other customers under the Company's proposal.

It is important to note, the cap mechanism only applies to the classes that are included in the cost-of-service studies and through the reconciliation process in Statement O. Those customer classes that have rates based on their otherwise applicable schedule ("OAS") may show an increase (or decrease) in revenue beyond the set cap or floor amount.

14. Q. ARE THERE ANY DEVIATIONS FROM COST-BASED LEVELS REQUIRED BY NEVADA LAW?

A. Yes. The primary subsidy required at Nevada Power is related to the residential and small commercial NEM classes. Pursuant to Assembly Bill 405 ("AB405") from the 2017 Nevada Legislature, rates for NEM customers are not based upon their separate cost of service but rather are based upon rates developed from the combination of these customers and the OAS full-requirements customers. The revenue difference from what NEM customers pay, compared to their cost-based results, is allocated to all other customer classes in Statement O. Such allocations ensure that all customer classes, not just OAS full-requirements residential and small commercial customers who would otherwise disproportionately bear the brunt of this legislatively mandated subsidy, pay their share of Nevada's support for NEM. In this GRC, under the Company's proposal, that difference is approximately $52.7 million ($51.2 million for residential single-family NEM). Once again, it is important to note that when comparing this value to that presented in prior cases, one must understand that this case is only looking at the BTGR subsidy related to NEM customers, while in past cases both the BTGR and BTER NEM subsidies were calculated and shown.

15. Q. WHY DOES THE COMPANY PROPOSE A 1.25 PERCENT CAP FOR RS CUSTOMERS?

A. A 1.25 percent cap above the 19.1 percent overall BTGR revenue requirement increase for RS customers mitigates the rate impact of the cost-based result that would otherwise implement a 26.7 percent increase for these customers. To limit the overall impact on standard RS customers but still make a measured movement towards the combined cost-based levels, an increase set slightly above the system average increase is appropriate in this case. This results in an overall subsidy to RS customers of $34.8 million under the Company's proposal. For comparison purposes, if the Company were to propose a 0 percent cap, above the system average increase, which is more consistent with previous GRC filings, the overall subsidy to RS customers would be $41 million. The implementation of the proposed RS Cap and the resulting subsidy can be found on page 9 of Statement O, sponsored by Ms. Prest.

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16. Q. WHAT IS THE COMPANY'S PROPOSAL FOR THE BSC IN THIS FILING?

A. For commercial customers, the Company proposes maintaining the BSCs at current levels for all classes except for the small general service class ("GS") and the optional small general service time-of-use ("TOU") class ("OGS"). The proposed BSC for the GS class reflects a $5.25 (20.6 percent) decrease from the current $25.50 monthly fixed charge to $20.25. This decrease both reflects a movement toward a cost-based BSC for GS customers, as well as the implementation of a demand charge rate component which I will discuss in further detail later in this testimony. Ms. Prest provides proposed rates, including BSCs, in her testimony.

For residential customers, the Company is proposing to maintain the RS customer BSCs at the current $18.50 per customer per month. A fully cost-based BSC in this case would have resulted in a proposed charge of $39.24 per customer per month, using the results of the ECS. A charge that maintains the same cost components that were reflected in the current BSC would have resulted in a proposed BSC of approximately $19. In lieu of proposing an increased BSC in this case, the Company is putting forward an alternative rate design structure which includes a demand charge rate component for all residential and small commercial classes. If the Commission does not opt to move forward with the new demand charges, the Company would alternatively request that an increased BSC be approved for residential and small commercial classes, as addressed in the testimony of Janet Wells.

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17. Q. WHY IS THE COMPANY NOT PROPOSING TO INCREASE THE BSC IN THIS GRC?

A. The Company considered proposing an increase to BSCs similar to that which was proposed in the 2024 Sierra GRC (Docket No. 24-02026). Specifically, in that case, Sierra asked for a fully cost-based BSC to recovery all distribution costs in the fixed monthly charge. That proposal, which was the simplest solution due to the two-part structure of the rates, would have reduced subsidies between NEM and non-NEM customers and provided more overall bill stability to customers. However, Sierra received feedback in that case, including from members of the public, that the proposal was (1) perceived as unfair treatment of low-income households, which the intervenors claimed to be predominantly low-usage customers, and (2) counterproductive to conservation efforts. In order to address those concerns, the Company decided to move forward instead with a proposal for a low-income discount to qualifying customers as well as the residential and small commercial demand charge proposal, which is discussed in more detail below.

18. Q. PLEASE DESCRIBE THE COMPANY'S RESIDENTIAL AND SMALL COMMERCIAL DEMAND CHARGE PROPOSAL.

A. The Company is proposing to implement a demand-based rate component to residential and small commercial customer bills. Currently at Nevada Power, commercial customer classes larger than the GS class already have a demand charge billing component (for the Large General Service, LGS-1 class) and multiple demand charges including TOU demand charges for the larger classes, LGS-2 and above. Residential and GS customer classes currently have what is called a two-part rate structure consisting of only the BSC and a flat (or in some cases optional TOU) volumetric dollar-per-kilowatt-hour charge, which recover all costs for those classes.

The proposed demand rate component will be charged on a daily maximum demand basis for residential customers, while GS customers will have a new monthly maximum demand charge to maintain consistency with other commercial classes, such as LGS-1.

19. Q. WHICH COSTS ARE THE COMPANY PROPOSING TO INCLUDE IN THE RESIDENTIAL AND SMALL COMMERCIAL DEMAND CHARGE?

A. The Company proposes to recover a portion of distribution costs in the daily maximum demand charge for residential flat rate customers and the monthly maximum demand charge for GS flat rate customers. Ms. Prest discusses the cost recovery breakdown in more detail in her prepared direct testimony.

20. Q. WHAT IS THE DIFFERENCE BETWEEN A CUSTOMER'S DEMAND AND THEIR ENERGY USAGE?

A. Put simply, a customer's demand reflects the maximum amount of strain the customer puts onto the utility's grid at any time during the relevant recording period. A customer's energy usage is the total amount of energy used over the period reflected on their monthly bill.

In another context, think of the concept of a person filling up a swimming pool. At the beginning of the customer's month of billing, the person has an empty swimming pool (i.e. zero kilowatt hours ("kWh") used to start the period) and a hose which is then connected to various pieces of water infrastructure feeding back to a well or municipal water supply (analogous to the electric infrastructure in place to serve the customers energy needs). In this example, the hose represents the maximum amount of water that can be accessed by the individual at any one time. If they were to turn on the water to its maximum level, this represents the customer's maximum level of demand at any one time. The swimming pool on the other hand represents the total amount of water the person will use over the period of time reflected on their bill, which is analogous to the total amount of kWh shown on a Nevada Power customer's bill.

In this example, the hose and other water infrastructure represents the fixed costs of Company electric facilities installed to serve every Nevada Power customer on the system. If the individual chooses to fill their pool more slowly by only turning on the water at a very low flow level, the size of the hose and other infrastructure does not decrease in size or capacity. This is what is meant by a fixed cost or the costs that do not vary with how much the person uses them, whether it be how far they crank the hose spigot on or how much electricity usage they concurrently have at any one point in time.

21. Q. ARE DEMAND CHARGES TOO COMPLEX OF A CONCEPT FOR A NEVADA POWER RESIDENTIAL CUSTOMER?

A. No, I do not believe so. The complexity issue is one that is very often relied on by opponents of residential demand charges. I believe that this argument can be misleading to decision makers. The concept of the demand charge construct is not in and of itself complicated. Quite simply explained, by turning more appliances on at a single point in time, a customer will be putting a greater strain on the electrical grid than they would if they were turning on only one appliance at a time. Further, an electric clothes dryer uses more electricity than an LED light bulb. These are not

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complex algorithms that a customer will need to fully study to understand how to affect their bill. As for which appliances use the most energy, most new appliances include electricity requirements stated on the label. I believe that these concepts are easily understood by residential customers.

22. Q. WHY IS THE COMPANY PROPOSING THE RESIDENTIAL AND SMALL COMMERCIAL DEMAND CHARGES AT THIS TIME?

A. There are three primary reasons for the Company's proposal in this proceeding. First, the demand charge billing component represents a step forward in the ability for the Company to more accurately price the service that it provides, while at the same time maintaining a customer's ability to control their bill in a way that reflects how they utilize the utility's system. The better reflection of cost causation through effective price signals results in not only increased equity between customers, but also communication with the customer about how their behavior affects costs. Second, Directive 10 in the Commission's Modified Final Order in Nevada Power's 2023 GRC (Docket No. 23-06007) required that the Company "shall file alternative rate methodologies or regulatory solutions to mitigate the calculated shortfall for the Assembly Bill 405 Net-Energy-Metering Regulatory Asset." The proposed demand charges represent part of this mitigation effort. Third, the adoption rate of NEM in the Nevada Power service territory has continued to grow at a rapid rate. It is now more important than ever for the utility to put in place better pricing mechanisms to protect both the Company as well as all other customers who right now are bearing the brunt of the subsidies that are, and have been, in place benefiting NEM customers.

23. Q. HOW DOES THE IMPLEMENTATION OF A DEMAND CHARGE PROVIDE A MORE ACCURATE PRICING STRUCTURE THAN WHAT IS CURRENTLY IN PLACE?

A. The current two-part (BSC and volumetric) rate structure in place for residential and small commercial customers is a blunt object that, while very simple, does not accurately reflect either the nature of the service the utility provides nor the amount of that service the customer uses. Including the demand charge creates a three-part rate structure that, along with the fully fixed and fully volumetric rate components, provides another way for a customer to control their monthly bill while also better reflecting the cost characteristics of the utility facilities that are installed throughout the service territory.

24. Q. HOW DOES THE IMPLEMENTATION OF A DEMAND CHARGE ADDRESS THE AB405 REGULATORY ASSET SHORTFALL?

A. The AB405 regulatory asset reflected the shortfall created by customers transitioning to NEM service in between GRCs. This shortfall is created because, under the current NEM regime, NEM customers have the ability to avoid much of the cost required to provide service to them by way of both statutorily mandated and Commission-enabled mechanisms in place at this time. This is in part due to:

1. Current rate design for all customers includes costs that are more fixed in nature being recovered through a variable rate;
2. Statutorily required excess energy credits far exceeding the value of the energy being produced;
3. Statutorily required rates charged to NEM classes being far below cost-based levels; and

4. The current NEM billing mechanism overstates the amount of excess energy, which is credited at 100 percent of the full retail rate for energy versus the statutorily mandated 75 percent for the currently open tranche of NEM customers.

The implementation of a demand charge for residential and small commercial customers is a step toward addressing the first item listed above, considering a demand charge is more fixed in nature than how those fixed costs are currently recovered through the volumetric rate component. In addition, while a customer may be able to somewhat lessen their overall peak demand when installing a NEM system, the amount of the fixed costs that they will be able to avoid with a demand charge will be reduced to a more appropriate level. To the extent a NEM customer can reduce their overall maximum demand, it is appropriate that they will be able to reap the benefits of such a behavioral change through their monthly bill. This is true for both NEM and full requirements customers.

25. Q. HAS THE PROBLEM THAT AB405 WAS ENACTED TO ADDRESS BEEN SOLVED?

A. No, in fact it continues to grow at a rapid pace, so it is increasingly important for the Commission to take steps to stem the tide of revenue that is flowing from non-NEM customers to subsidize NEM customers. In the 16 months from the closing of the certification period in the 2023 Nevada Power GRC (May 31, 2023) through the closing of the Test Period in this GRC (September 30, 2024) 22,238 new NEM customers were added to Nevada Power's system. Continuing through January 31, 2025, another 4,747 NEM customers were added to the system, bringing the total NEM customers in Nevada Power's service territory to 116,493.

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26. Q. HOW MUCH OF THE AB405 REGULATORY ASSET SHORTFALL IS ADDRESSED BY THE IMPLEMENTATION OF A DEMAND CHARGE RATE COMPONENT?

A. The simplest way to quantify the impact of implementing a demand charge rate component for residential and small commercial customers on the AB405 regulatory asset is by showing its impact on the average NEM customer who transitions from full requirements to NEM in between GRCs. Using data from existing NEM customers, the average annual contribution to the NEM regulatory asset is approximately $508 per new NEM customer. With the implementation of the demand charge, approximately $130 per year for the average NEM customer is shifted from the volumetric rate component to the demand charge rate component. While not a perfect comparison, using these assumptions, implementing the demand charge rate component will address approximately 25.6 percent of what was previously addressed with the AB405 regulatory asset for each incremental NEM customer.

27. Q. DOES THE DEMAND CHARGE RATE COMPONENT PROVIDE ANY OTHER BENEFIT TO NEVADA POWER CUSTOMERS?

A. Yes. While the AB405 regulatory asset was in place to help address the subsidization that would occur between GRC filings, as stated in my Q&A 14, in this case, there is also a $52.7 million subsidy in BTGR revenue that flows from NEM customers to all other customer classes. This is a subsidy that is paid directly by other customers and assessed at each GRC. Without the residential and small commercial demand charge proposal in this case, that subsidy will increase to $62.9 million ($61.4 million of which is from RS NEM customers).

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28. Q. IS THIS DEMAND CHARGE JUST ANOTHER WAY FOR NEVADA POWER TO INCREASE REVENUE AT THE EXPENSE OF CUSTOMERS?

A. No, it is not. First, it is important to note that when implemented in a GRC, there is no increase in revenue related to the demand charge proposal. The same amount of revenue requirement is spread to the same customers, only now through three rate components instead of two. There is no additional revenue requirement recovery as a result of this proposal. Second, while there will be an additional amount of revenue recovered from new NEM customers in between GRCs, this is only a small part of the revenue that was previously recovered by way of the AB405 regulatory asset as discussed in Q&A 26 above.

29. Q. IS A DAILY MAXIMUM DEMAND CHARGE THE MOST COST-REFLECTIVE CHARGE THE COMPANY COULD HAVE PROPOSED IN THIS CASE?

A. No. An annual maximum demand charge structure such as the demand charges that larger commercial customers at Nevada Power pay would be the most cost-reflective charge for residential and small commercial customers as well, given the inability to enact mandatory TOU, or seasonal, demand rates. Explained simply, the Company's facilities that are built to serve customers must be able to provide the maximum amount of energy that a residence or business requires at any point in time. These facilities do not shrink and grow from day to day based on a customer's usage in a 24-hour period. Nor do they regularly change over the course of a month or a year. Because of this, a maximum demand over a longer period in time provides a more cost-reflective picture of how any customer is utilizing the system. However, in order to maintain consistency between similar commercial customer classes, the Company is proposing the GS demand charge be based on each customer's monthly maximum demand.

30. Q. IF THAT IS THE CASE, WHY DID THE COMPANY NOT PROPOSE A MONTHLY OR ANNUAL MAXIMUM DEMAND CHARGE FOR RESIDENTIAL CUSTOMERS?

A. While a strict cost basis is always the Company's goal when designing rates, there are other aspects that need to be considered, particularly when introducing a population of customers to a new concept that may be unfamiliar. The longer the timeframe used to collect a customer's maximum demand placed on the system, the less forgiving that cost recovery mechanism is. While this is appropriate when looking at the types of distribution facilities that are being recovered through the demand charge, it is more punitive to a customer who may have inadvertently turned on their pool pump, electric clothes dryer, air conditioning unit, space heater, toaster, microwave, and arc welder all at the same time. If that situation occurred in an annual maximum demand rate component, this customer would be paying the higher maximum demand for the entire next 12-month period. Similarly, with a monthly maximum demand, this customer would face the impact of those choices for the full month. So, while the daily maximum demand charge is not the most cost reflective, it does provide customers with a measure of leniency for the situations when too many appliances are running concurrently on a given day.

31. Q. DOES THE DAILY DEMAND CHARGE PROVIDE CUSTOMERS WITH THE ABILITY TO CONTROL THEIR MONTHLY BILL?

A. Yes, and with proper understanding of how a demand charge works, I believe it is actually easier to control one's bill than with the two-part rate structure.

32. Q. PLEASE EXPLAIN.

A. With a two-part rate structure, a customer is only able to control the level of their bill with one lever, the total amount of usage over the period being billed. With the added demand charge, a customer has the added lever of being able to save more money by spreading out their usage over time. In this sense, a customer is able to use the same total amount of energy in a month and still realize bill savings compared to what they would have experienced in the existing rate structure.

33. Q. DID THE COMPANY CONSIDER OTHER OPTIONS FOR THE DEMAND CHARGE WHEN DEVELOPING THIS PROPOSAL?

A. Yes. In addition to considering the option of the monthly peak demand-based charge as I discussed previously, the Company also considered which costs should be recovered by the charge. There is an argument to be made that transmission and generation capacity costs are similar to distribution costs, in that they are more fixed in nature than they are variable and, therefore, can be appropriately recovered through a demand charge. Ultimately, the Company chose to limit the costs recovered by the demand charge to those in the distribution function in order to maintain consistency with the proposal in the Sierra GRC as well as to enable a smaller demand charge for customers as they transition to the three-part rate design and billing.

34. Q. HOW WILL THE COMPANY ENDEAVOR TO INFORM AND EDUCATE CUSTOMERS ABOUT DEMAND CHARGES PRIOR TO THESE APPEARING ON A MONTHLY BILL?

A. First and foremost, education is of the utmost importance for both customer acceptance and understanding of any new program or rate design. The Company is fully aware of this and is committed to providing educational materials and tools to communicate what this change means, how it will impact them, and how to best take advantage of the more advanced rate structure. In the preparation of this filing, teams within the Company have been collaborating and several workstreams have begun with regard to customer education and communication of the Company's proposals in this GRC. For demand charges specifically, we have looked at other utilities across the country who do have a residential demand charge component in their rates and have taken a close look at the educational materials they have available for customers. For example, **Figures Bohrman Direct-1** and **Bohrman Direct-2** below show illustrations from Arizona Public Service ("APS") on just how simple and easy it is to adjust appliance usage to better control a customer's maximum draw from the utility's system.[2] Similarly, **Figure Bohrman Direct-3** below shows a table from Georgia Power Company illustrating "The Smart Usage Concept."[3] The Company's plan is to leverage these types of materials that already exist as examples on which to base our own educational materials and platform.

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[2] *See* https://www.aps.com/en/Residential/Save-Money-and-Energy/Your-Energy-Your-Options/Energy-Saving-Tips/Peak-Hour-Usage, and https://www.aps.com/en/Residential/Service-Plans/Compare-Service-Plans/Time-of-Use-4pm-7pm-Weekdays-with-Demand-Charge.

[3] *See* https://www.georgiapower.com/residential/billing-and-rate-plans/pricing-and-rate-plans/smart-usage.html.

Figure Bohrman Direct-1 – APS Educational Material on How to Respond to Demand Charges ("Do")

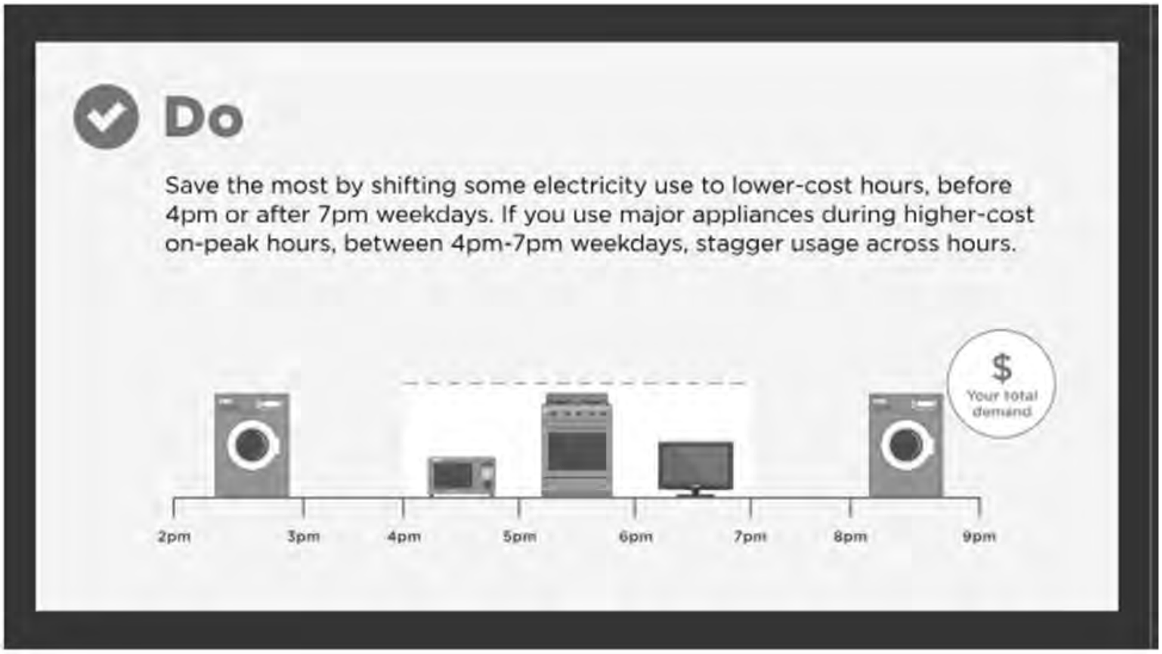


Figure Bohrman Direct-2 – APS Educational Material on How Not to Respond to Demand Charges ("Don't")

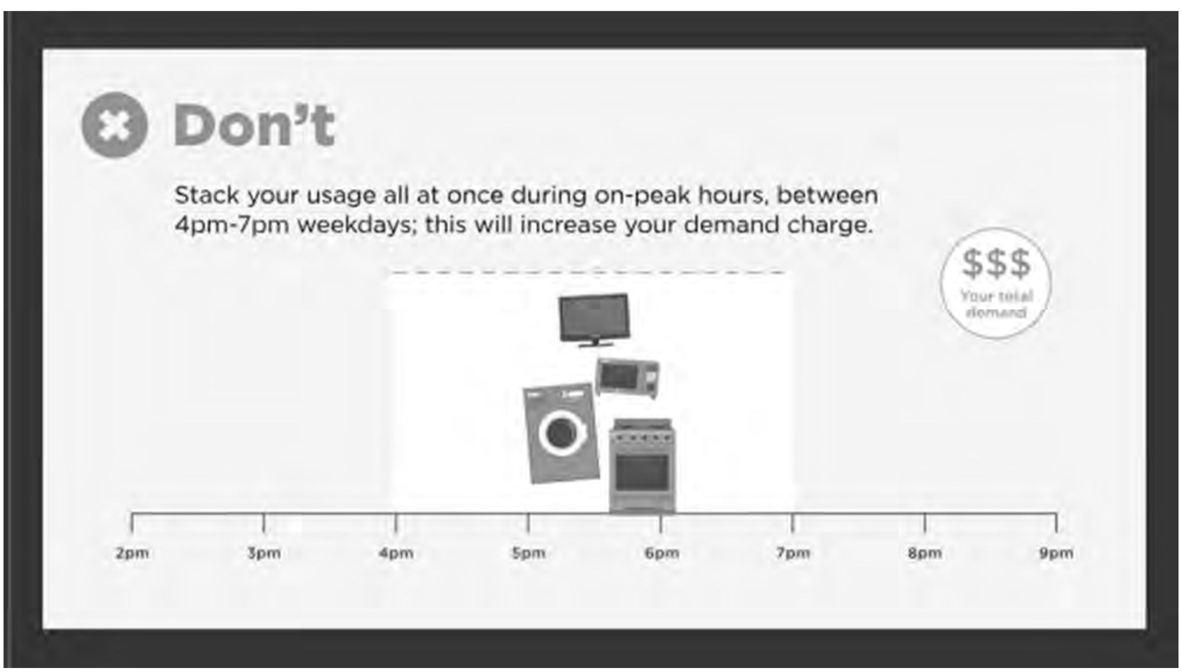
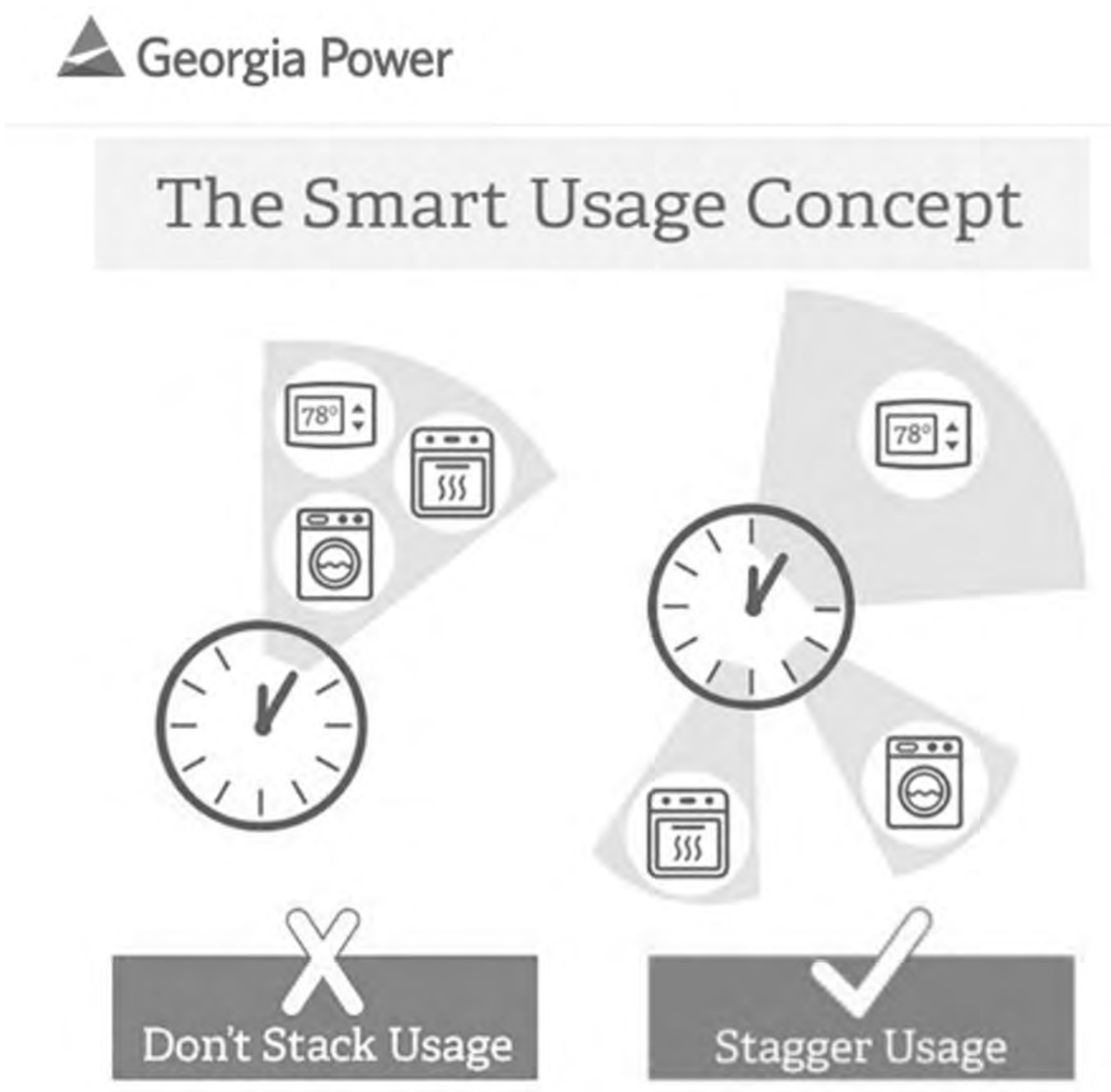


Figure Bohrman Direct-3 – Georgia Power Co. Educational Material on The Smart Usage Concept



35. Q. WHEN DOES THE COMPANY PROPOSE RESIDENTIAL AND SMALL COMMERCIAL DEMAND CHARGES WILL BE EFFECTIVE?

A. In order to ensure that customer communication and education programs are in place, as well as to ensure that billing changes and implementation is fine-tuned and working correctly, the Company is requesting an extended effective date of April 1, 2026. This will provide an extra six months of time to put the changes into place while also coinciding with an already scheduled date of a Company rate change for BTER in 2026 Quarter 2.

36. Q. IS THE COMPANY FILING REVISED TARIFFS THAT REFLECT THE DEMAND CHARGE RATE COMPONENT?

A. Yes. The demand charge rate component will require small changes to several of the Company’s existing residential and small commercial tariffs. These changes are reflected in **Exhibit A** to the filing. Additionally, **Exhibit Bohrman Direct-5** includes redlined versions of the proposed tariffs, which show where additions and/or edits have been made to reflect the proposed rate component. The redlined tariffs will reflect the following changes, which vary slightly by the type of schedule:

- Schedules RS, RM, and LRS: these flat rate residential schedules have a new Special Condition 2 added, which describes the daily demand charge.
- Schedules ORS, ORM, and OLRS: these optional TOU residential rate schedules have two new Special Conditions added, numbers 7 and 8, which describe the daily demand charge as well as TOU based demand charge.
- Schedules ORS-CPP, ORM-CPP, and OLRS-CPP: these optional TOU residential rate schedules with a critical peak pricing period also have two new

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Special Conditions added, numbers 9 and 10, which describe the daily demand charge as well as TOU based demand charge.

- Schedules ORS-CCP+DDP, ORM-CPP+DDP, and OLRS-CPP+DDP: these optional TOU residential rate schedules with a critical peak pricing period and a daily demand price already are effective, however the rate design methodology changes for them slightly to (a) bring the schedules in line with the already existing optional DDP schedules rate design, and (b) to provide customers with a differentiated option from what is now the standard RS. This editing wording occurs in the Rates section of the tariff and discusses the schedules' BSC.
- Schedule GS: this flat rate small commercial schedule has a new Special Condition 2, which describes the monthly maximum demand charge.
- Schedule OGS: this optional TOU small commercial schedule has two new Special Conditions, numbers 7 and 8, which describe the monthly maximum demand charge as well as TOU based demand charge.
- Schedule OFP: Contains small edits to Special Conditions 10 and 11, which discuss the specific bill components these customers are responsible for.

37. Q. OUTSIDE OF APS AND GEORGIA POWER COMPANY NOTED ABOVE, IS THE COMPANY AWARE OF ANY ADDITIONAL UTILITIES IN THE UNITED STATES WITH RESIDENTIAL DEMAND CHARGE PROGRAMS?

A. Yes. While residential demand charges are not widely used throughout the United States, they are in place in a number of jurisdictions. In addition to APS and Georgia Power, the Company has identified residential demand charge options at Salt River Project (AZ), Otter Tail Power (MN), Alabama Power (AL), and Consolidated

Edison (NY). As the Commission is well aware, Nevada has several unique aspects, requirements, and/or restrictions in place that do in fact coincide with such an implementation that other jurisdictions may not be faced with. In addition, Ms. Williams' prepared direct testimony discusses the implementation at other utilities as well as her overall opinion of their effectiveness.

IV. <u>LOW-INCOME RATE DISCOUNT PROPOSAL</u>

38. Q. PLEASE DESCRIBE THE COMPANY'S LOW-INCOME RATE DISCOUNT PROPOSAL.

A. The Company's low-income discount rate proposal in this case is to provide a 100 percent discount on qualifying customers' BSCs for a 12-month period. The qualification threshold is proposed to include customers whose income falls under 150 percent of the Federal Poverty Level. The discount is proposed to appear on a customer's bill as a separate line item, with a credit amount equal to the full BSC for their respective customer class. Customers may reapply every year in which they qualify for the program under this proposal. Mr. Will provides a more in depth look and discussion of the low-income rate discount proposal in his prepared direct testimony.

39. Q. WHY IS THE COMPANY PROPOSING A LOW-INCOME RATE DISCOUNT IN THIS GRC?

A. Directive 9 of the Modified Final Order in Nevada Power's 2023 GRC (Docket No. 23-06007) required that the Company "shall file a proposal to establish low-income rates as allowed pursuant to NRS 704.110(14)(b)." The Company's proposal in this GRC is meant to satisfy this Commission Directive.

40. Q. WHAT IS THE EXPECTED IMPACT OF THE COMPANY'S PROPOSAL FOR QUALIFYING CUSTOMERS?

A. Mr. Will discusses the impacts and costs to implement the proposal in his prepared direct testimony. Additionally, Mr. Will illustrates the expected impact to a participating customer. At a high level, the total annual bill savings that would be provided to approximately 154,000 qualifying customers, with 100 percent participation, would be approximately $28.2 million per year. The cost to administer the program is estimated to be approximately $2 million per year.

As I discussed previously in Section III of this testimony, the Company's proposal in this case does reflect certain intra-class subsidies, or in other words the shifting of revenue recovery from one set of customers to all others. Specifically, the NEM subsidy that has been discussed is an example of one such revenue recovery shift. Another example of a revenue recovery shift being incorporated in the Company's proposal is the implementation of the 1.25 percent RS cap. These public policy considerations are in place to comply with either legislative mandates or to mitigate rate shock, and the low-income discount proposal is likewise being proposed in response to the Commission's directive. What is being proposed in this GRC is the Company's first attempt to show what such a program can look like, coupled with the resulting costs to implement such a program and the overall expected benefits it will provide.

Finally, it is important to note that there are utility-based assistance programs that already exist in Nevada that support the community targeted by the Company's proposal. For instance, customers in southern Nevada already have access to Project REACH and the Nevada Energy Assistance Program. In addition, there are a number of other programs that aim to provide needed assistance with home weatherization upgrades, qualified appliance replacements, as well as education programs for our senior and disabled customers. Participants in these programs will also be allowed to partake of the Company's proposed low-income discount program.

41. Q. IS THE COMPANY REQUESTING REGULATORY ASSET TREATMENT FOR THE LOW-INCOME SUBSIDY AMOUNT AS WELL AS THE COST TO ADMINISTER THE PROGRAM?

A. Yes. Ms. Naughton describes the regulatory asset request in her prepared direct testimony.

42. Q. IF APPROVED, WHEN DOES THE COMPANY PROPOSE THE LOW-INCOME RATE DISCOUNT WILL BE AVAILABLE FOR CUSTOMERS?

A. Due to the creation of a new process of accepting and vetting applications, implementing the discount mechanism into the billing system, and educating internal customer resources, the Company would require an adequate amount of lead time before the low-income rate discount program could be effective. At this time the Company estimates it could have the program running by April 1, 2026, however, this implementation date could change in the future as the work progresses.

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V. EXCESS ENERGY NETTING FOR NEW NEM CUSTOMERS PROPOSAL

43. Q. PLEASE DESCRIBE THE COMPANY'S NEM EXCESS ENERGY NETTING PROPOSAL.

A. The Company's proposal is to implement a tariff for new NEM customers that provides a more appropriate methodology for measuring and valuing the excess energy placed back onto the Company's system. The proposed methodology will net excess energy on a 15-minute basis, versus the current mechanism that compiles and nets excess energy at the time a customer's monthly bill is calculated.

Below I will first describe the currently existing NEM tariffs in Nevada Power's service territory. Additionally, **Exhibit Bohrman Direct-4** provides a brief overview of the recent regulatory history of NEM in Nevada from 2013 to present. Then I will outline in more detail why the Company is proposing such a methodology at this time, how this mechanism is compliant with Nevada law, and discuss impacts to current and future NEM customers as well as impacts to non-NEM customers. Ms. Williams provides additional context to this proposal along with an outside perspective of the evolution of NEM throughout the country in her prepared direct testimony.

44. Q. PLEASE DESCRIBE NEVADA POWER'S CURRENT NEM TARIFFS.

A. Nevada Power currently supports four NEM tariffs for residential and small commercial customers of which two are available to new customers.[4]

- Schedule Net Metering Rider-A ("NMR-A") and Schedule Net Metering Rider-B ("NMR-B") established in Docket No. 15-07041;[5]

[4] NMR-B and NMR-405 are currently available to new eligible NEM customers.
[5] Docket No. 15-07041, February 17, 2016, Modified Final Order, at Section V. paragraph 358, p. 160.

- Schedule Net Metering Rider-G ("NMR-G") established in Docket No. 16-07028;[6] and
- Schedule Net Metering Rider-405 ("NMR-405") established by Assembly Bill 405 (2017) and implemented in Docket No 17-07026.[7]

For all four tariffs, under NRS 704.773(2)(c), customers served under the rider pay rates based on their otherwise applicable rate schedule.[8]

NMR-A Tariff

The NMR-A tariff applies to customers with renewable energy electrical generation facilities (e.g., rooftop solar) or waterpower electrical generation facilities installed between January 1, 2016, and June 4, 2017, with a capacity of not more than 1,000 kilowatts.

For NMR-A customers, Nevada Power compiles the separately metered energy sent to the grid or consumed during the monthly billing period in kilowatt-hours. Customers generating excess energy that is delivered to the grid are compensated with monetary energy credits, which are carried forward to future billing periods, if the credits exceed the billed amount in the current period. No netting occurs for customers in Schedule NMR-A. These customers had the option to migrate to NMR-405 in 2017, as they still do today, but a handful have chosen to remain.

If customers consume more energy than their system generates, Nevada Power will bill for the additional consumption, reduced by any credit balance from previous

[6] Docket No. 16-07028, September 16, 2016, Order (Stipulation Accepted), at Section IV. Paragraph 2, p. 3.
[7] Docket No. 17-07026, March 14, 2018, Order (Stipulation Accepted), at Section IV. Paragraph 3, p. 4.
[8] NRS 704.773(2)(c): "Except as otherwise provided in subsection 7, shall not charge the customer-generator any fee or charge that is different than that charged to other customers of the utility in the rate class to which the customer-generator would belong if the customer-generator did not have a net metering system."

billing periods. Any remaining credits at the end of the year are paid to the customer via check.

NMR-G Tariff

On September 30, 2016, Governor Sandoval's New Energy Industry Task Force recommended that NEM systems installed, or active applications issued on or before December 31, 2015, be grandfathered under the original NEM terms for 20 years.[9] In response, Nevada Power created the NMR-G tariff. The "Grandfathered Rates" applicable under the tariff mirror NMR-B with non-monetary excess energy credits indefinitely carried over to future bills. After the 20-year period, these customers will be billed pursuant to the otherwise applicable non-grandfathered rate schedule currently in effect at that time.

NMR-B Tariff

The tariff structure of NMR-B is quite similar to the former NMR-G with the key differences that the customer-generation capacity must be greater than 25 kilowatts. The NMR-B remains open for large NEM systems.

NMR-405 Tariff

The NMR-405 tariff applies to systems applied for or installed after June 15, 2017, as established by AB405.[10] Unlike previous tariffs, NMR-405 features four tiers with varying excess energy credits, assigned to customers on a first-come, first-served basis:

- Tier 1: Excess energy credit is 95 percent of the retail volume electricity rate

[9] Executive Order No. 2016-04 (2016)

[10] A.B 405, 2017 Leg., 79th Sess. (Nev. 2017)

- Tier 2: Excess energy credit is 88 percent of the retail volume electricity rate
- Tier 3: Excess energy credit is 81 percent of the retail volume electricity rate
- Tier 4: Excess energy credit is 75 percent of the retail volume electricity rate

Tiers 1-3 caps on installed capacity have been met while Tier 4 does not have a cap on installed capacity and, therefore, is the only currently available option to new NEM customers with systems sized below 1,000 kW. The tranche assignment is determined by the date the customer's application is received by Nevada Power and applies for 20 years. Excess energy credits at the end of the year are carried over to future billing periods. Customers currently in the NMR-G or NMR-A rate class have the option to move to the NMR-405 rate class and would be placed in Tier 4.

45. Q. IS THE COMPANY PROPOSING A NEW NEM RIDER WITH THIS GRC?

A. Yes. Schedule NMR-2025 is included with **Exhibit A** and A1 to this GRC filing. This revised tariff reflects the updated netting mechanism and removes an outdated reference to a defunct billing component, but otherwise is consistent with the existing Schedule NMR-405 tariff. For convenience, **Exhibit Bohrman Direct-5** attached to my testimony is a redlined version of the current NMR-405 tariff modified to show the edits made to the NMR-405 tariff to create the newly proposed NMR-2025 tariff.

46. Q. HOW IS EXCESS ENERGY HANDLED FOR EXISTING NMR-405 CUSTOMERS?

A. At the end of each billing cycle, the delivered and received energy for an NMR-405 customer that has been compiled over the month is netted against each other. In other words, if the amount of excess energy the NMR-405 customer has placed on the grid during the month exceeds that which the customer was delivered by

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Nevada Power, the NMR-405 customer will receive a monetary credit equal to 75 percent (under Tier 4 of the NMR-405 tariff) of the full retail rate for each kWh of net excess energy. Conversely, if the customer was delivered more energy during the month from the Company than their NEM system put onto the Company's system, they will be billed based on the effective rates for their appropriate rate schedule. Practically speaking, this mechanism provides for a value of excess energy of 100 percent of the full retail rate for all excess energy up to and including the amount consumed by the customer over the full monthly billing period. For example, in a summer month when a customer is likely consuming the most: (1) assume the energy delivered is 200 kWh; and (2) assume in that same month, the customer's generation sent back 100 kWh of energy to the system. Because the customer had more delivered energy than energy sent back to the grid, all 100 kWh sent back to the grid are credited at 100 percent of the retail rate because it offsets one-for-one the delivered energy. The credits are applied regardless of the time of day the energy is sent back and therefore may not reflect the value of that energy.

47. Q. HOW DOES THE COMPANY'S PROPOSAL IN THIS CASE DIFFER FROM THE CURRENT MECHANISM?

A. The Company is proposing a change from monthly netting to 15-minute netting. All kWh of energy produced and not consumed by the customer-generator and fed back to the grid will be priced and compensated at the time they are fed back to the grid. All of the kWh delivered by the utility will be charged the rates for utility service.

48. Q. WHEN WAS THE LAST TIME THE COMMISSION ADDRESSED NETTING FOR CUSTOMER-GENERATORS?

A. The last time the Commission addressed netting for customer-generators was in Docket No. 17-07026 on pages 15-19 of the Order issued September 1, 2017. However, as the Commission is aware, prior Commission decisions have no precedential effect.

49. Q. WHY IS NEVADA POWER PROPOSING THIS CHANGE TO NEM NOW?

A. Nevada Power is proposing this change because, in Directive 10 of the Modified Final Order in Docket No. 23-06007, the Commission mandated that Nevada Power propose alternative rate methodologies or regulatory solutions to mitigate the calculated revenue shortfall associated with NEM in its next GRC. In conjunction with the residential and small commercial demand charge outlined beginning in Q&A 18 above, the Company's proposals in this proceeding address some, but not all, of the revenue shortfall. Additionally, this 15-minute netting proposal addresses a significant shifting of costs from NEM customers to all other full requirements customers.

50. Q. WHAT IS THE STATUTORY AUTHORITY FOR A 15-MINUTE NETTING MECHANISM?

A. While I am not an attorney, I have sufficient knowledge of Nevada's existing statutory requirements to provide my policy perspective. From that perspective, I believe Nevada Revised Statutes provide several areas of guidance that provide authority for a 15-minute netting mechanism. First, NRS 704.7732(1) states that "the utility must, in accordance with this section, provide to the customer-generator a credit for <u>each kilowatt-hour of excess electricity.</u>" (emphasis added)

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Additionally, NRS 701.540(4) also states that customer-generators are entitled to "[f]air credit for any energy exported to the grid." (emphasis added)

NRS 704.7732(1) applies to customer-generators who accept NEM on or after June 15, 2017, and whose NEM system is not more than 25 kW. The credit must equal a percentage (as set forth in NRS 704.7732(3)) "of the rate the customer-generator would have paid for a kilowatt-hour of electricity supplied by the utility at the time the customer-generator feeds the kilowatt-hour of excess electricity to the utility." (emphasis added) The credit is currently set at 75 percent (see NRS 704.7732(3)(d)). So, the customer-generator pays for every kWh of electricity delivered by the utility and receives a credit for each kWh of electricity delivered to the utility's system, currently 75 percent.

Finally, NRS 701.540(6) states that the customer-generator has the right to "[h]ave his or her generation of renewable energy given priority in planning and acquisition of energy resources by an electric utility." This prioritization further supports the framework that every kWh of electricity produced by the customer-generator and fed back to the grid must be accounted for.

51. Q. WHAT IS THE EFFECT OF 15-MINUTE NETTING?

A. A customer-generator will pay for each and every kWh that the Company delivers to them in the metering interval the customer-generator requires them, and the customer-generator will receive an excess energy credit of 75 percent of the retail rate for each and every kWh that the customer-generator delivers to the grid during the 15-minute interval in which the customer-generator produces the excess energy.

52. Q. DOES NRS 704.775 REQUIRE MONTHLY NETTING?

A. No. Monthly netting ignores the vast majority of excess energy actually delivered to the grid during the billing period. In fact, monthly netting seems less consistent with the statutory requirements, as one cannot truly conduct monthly netting and still apply a credit to kWh at the time it was delivered to the grid in conformance with NRS 704.7732(1) and 704.7732(3)(d).

Meters for customer-generators measure instantaneous flow and record each kWh in a register over every 15-minute period and sum to hourly or the applicable TOU period for billing purposes. Therefore, the net electricity consumed by the customer-generator in a billing period is the sum of kWh delivered to the customer by the Company and recorded by the meter. The net electricity produced by the customer after contemporaneously serving their own load is the sum of the received kWh recorded by the meter.

53. Q. WHAT ARE THE NEGATIVE IMPACTS OF MONTHLY NETTING?

A. Because monthly netting occurs at the end of the billing cycle when the bill is calculated, the energy actually fed to the grid during the month is not evident to a customer. As most energy fed to the grid is netted against a customer's electricity usage at the end of the billing cycle, it is effectively valued at 100 percent of the full retail rate of electricity. The quantity of "excess" then remaining and applicable to the 75 percent credit rate is very small, just a fraction of the monthly excess energy actually put on the utility's grid in a billing period. In twelve months ending March 31, 2024, 320.6 million kWh were fed back onto the grid by NMR-405 Tier 4 customers. Of those, only 48.7 million kWh were compensated at the NRS-mandated 75 percent of the full retail rate for NMR-405 Tier 4 customers—just 15

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percent of the total kWh that were fed back to the grid over the year. The remaining 85 percent were compensated at 100 percent of the full retail rate. As such, by abandoning normal metering practices, the majority of the excess energy fed to the grid is effectively priced at 100 percent of the full retail rate. This is misaligned with the statutory mandates in NRS 704.7732(2) and 704.7732(3) as compared to the more timely netting that would result from a 15-minute interval.

NRS 704.7732(2) states that "[t]he credit for <u>each [implying no netting]</u> kilowatt-hour of excess electricity described in subsection 1 must equal a percentage, as set forth in subsection 3, of the rate the customer-generator would have paid for a kilowatt-hour of electricity supplied by the utility <u>at the time [implying no netting]</u> the customer-generator fed the kilowatt-hour of excess electricity back to the utility." (emphasis added)

NRS 704.7732(3) specifies the applicable percentage to be applied to the rate, which is currently set at 75 percent pursuant to subsection d. Nowhere is 100 percent specified.

54. Q. DOES THE MONTHLY NETTING MECHANISM PROVIDE TRANSPARENCY TO NEM CUSTOMERS?

A. No. Monthly netting actually does the opposite by masking the true nature of a customer's relationship with the utility. Nearly all NEM customers place significant portions of their on-site generation kWh back on the grid, receiving credit for that energy delivered to the Company. If NEM customers do not receive credit for energy delivered to the Company, they are essentially using the utility as a free battery. Netting over the month conceals the full transaction that is occurring between the utility and the customer-generator and shows a small fraction of the energy actually placed on the grid. As stated above, NMR-405 Tier 4 customers put back onto the grid almost 320.6 million kWh in the year ending March 31, 2024. Of those kWh, only 15 percent would be priced at less than 100 percent under monthly netting. The NRS framework is not truly supportive of applying the applicable credit amount to only a small portion of the kWh placed on the grid. In other words, “each” kWh certainly does not mean only 15 percent of the kWh.

55. Q. HOW ELSE DOES MONTHLY NETTING CONCEAL THE FULL TRANSACTION THAT IS OCCURRING BETWEEN A NEM CUSTOMER AND THE UTILITY?

A. The first column of **Table Bohrman-Direct-1** below shows the percent of NEM customers on Nevada Power’s system that put energy from their solar generator onto the utility’s grid over the 12-month period ending March 2024. The second column shows the percent of customers whose solar generation exceeds the amount delivered by the utility to them over the same period. The table shows that 96 to 97 percent of NEM customers produce excess energy in any month. Under monthly netting, as few as three percent of these customers would know that they had produced and delivered energy to other Nevada Power customers over that year.

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

Table Bohrman-Direct-1 – NEM Customer Delivered and Received Energy

	NPC Percent of NEM Customers with Received>0	NPC Percent of NEM Customers with Received>Delivered
January	97%	30%
February	97%	52%
March	97%	78%
April	97%	82%
May	97%	61%
June	97%	38%
July	97%	3%
August	97%	4%
September	96%	17%
October	97%	51%
November	97%	53%
December	97%	29%

56. Q. WHAT IS THE DIFFERENCE IN EXCESS ENERGY SENT TO THE COMPANY'S SYSTEM WHEN COMPARING 15-MINUTE TO MONTHLY NETTING?

A. As there are no customers yet who are under the 15-minute proposal, the Company calculated the impact using interval load data from existing NEM customers. Using the available data, the average NMR-405 Tier 4 customer's bill shows an excess energy amount of 578 kWh per year under the monthly netting mechanism. By utilizing 15-minute netting, the same customer's bill would show 4,937 kWh per year of excess energy returned to the Company's system. This is an increase of 754 percent of the amount of excess energy that a customer puts back onto the utility's grid that would now show up as an amount receiving the statutorily mandated credit on their annual bill rather than being credited at 100 percent.

57. Q. DOES MONTHLY NETTING RESULT IN A FAIR CREDIT?

A. No. The monthly netting results in compensation for excess energy that cannot be termed "fair" as set forth in NRS 701.540(4). In addition, monthly netting masks the transaction between the customer-generator and the utility. This adds confusion and unfairly increases the credit provided to customer-generators beyond the 75 percent credit value that the statute mandates.

58. Q. HOW DOES THE STATUTORILY MANDATED FAIR VALUE OF NEM EXPORTED ENERGY COMPARE TO THE ACTUAL VALUE OF NEM EXCESS ENERGY WHEN IT IS SENT TO THE UTILITY'S GRID?

A. **Table Bohrman-Direct-2** below shows a comparison of the full retail rate for RS-NEM customers, the statutorily-mandated 75 percent of the retail rate for NMR-405 Tier 4, and the weighted average value of the energy based on the Company's long term avoided costs ("LTAC") from the 2024 integrated resource plan ("IRP").[11] Additionally, the table shows the weighted average of the cost of three utility-scale solar projects that were approved in the 2024 IRP. Utility-scale solar provides a valuable comparison as it is apples-to-apples with the smaller scale NEM systems, particularly when considering the difficultly in quantifying societal benefits and externalities associated with solar energy production. As shown by the table, NMR-405 Tier 4 customers are receiving a premium of 223 percent over utility-scale solar for each excess kWh that is valued at 100 percent of the full retail rate and 142 percent for each kWh that is valued at 75 percent. This premium extends to 452 percent and 314 percent when compared to the LTAC for 100 percent and 75 percent credit values, respectively.

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Table Bohrman-Direct-2 – Excess energy value

	Full Retail ($/kWh)	NMR-405 T4 EEC ($/kWh)	Solar Only Projects* ($/kWh)	LTAC** ($/kWh)
	$ 0.11392	$ 0.08544	$ 0.03528	$ 0.02063
	Full Retail Premium	**NMR-405 T4 Premium**		
Solar Only Project	223%	142%		
Marginal Energy Cost	452%	314%		

*Weighted Average of Boulder Solar III, Arevia - Libra, and NextEra - Dry Lake East (2024 IRP)
**Long-Term Avoiced Cost Weighted by hours of NEM Excess Energy (2024 IRP)

59. Q. WHY IS THIS IMPORTANT?

A. There are two aspects of the premium paid to NMR-405 customers that are important to understand when contemplating the fairness aspect of monthly netting. First, the result of monthly netting unequivocally provides NMR-405 customers with a credit that far exceeds what can be considered a fair value of the excess energy they deliver back to the system. Whether comparing to either the LTAC or utility scale solar, **Table Bohrman Direct-2** shows that NMR-405 customers are provided an artificially high valuation of what they are providing to the utility's system, particularly when factoring in when this excess energy is delivered to the utility's system.

Second, the amount the Company pays NEM customers for the excess energy they put back onto the utility's grid is treated as a fuel and purchased power cost that then flows through the BTER mechanism. This means that all customers pick up the additional premium provided to NEM customers for each and every kWh that is sent to and purchased by the utility. This impact is isolated to all customers that pay the BTER and deferred energy accounting adjustment rate components on a dollar-for-dollar basis, with no impact on the Company's return or bottom line. This is a subsidy that is passed from NEM customers to all other customers in the service territory.

60. Q. WHAT IS THE IMPACT OF THE COMPANY'S PROPOSAL TO EXISTING NMR-405 CUSTOMERS?

A. The Company's proposal does not impact existing NMR-405 customers at all. The proposed change will take effect for all new NEM applications received on or after October 1, 2025. The Company views this as a fairness issue as these customers made investments based on the known circumstances at the time they purchased their rooftop solar systems.

61. Q. WHAT IS THE IMPACT OF THE COMPANY'S PROPOSAL TO NEW NMR-2025 CUSTOMERS?

A. The impact is that excess energy, which is energy delivered by NEM customers to the Company, will be netted on a 15-minute basis. **Table Bohrman-Direct-3** below provides an annual bill comparison between the current monthly netting settlement and the Company's proposed 15-minute netting settlement based on the load profile of the average RS-NEM customer. As the table shows, the average new NMR-2025 customer will receive $136 less annually ($11/month) than they would have under the monthly netting mechanism.

Table Bohrman Direct-3 – Estimated NMR-2025 Impact

Annual Bill Comparison - NMR-405 Tier 4												
Group	Delivered kWh	Received kWh	Diff kWh	Comp kWh	Billed kWh	BSC	BTGR	BTER	DEAA	Excess Energy Credit	Annual Total Bill	Monthly Total Bill
Monthly Netting	10,158	6,643	3,514	578	4,093	$ 222	$ 232	$ 251	$ 28	$ (54)	$ 678	$ 57
Fifteen Minute Netting	10,158	6,643	3,514	4,937	8,451	$ 222	$ 480	$ 518	$ 57	$ (462)	$ 814	$ 68

- Delivered kWh are what was sent from the utility to the customer
- Received kWh are what was sent from the customer to the utility's grid
- Compensated kWh are the kWh that receive the excess energy credit
- Billed kWh are what a customer is billed for

62. Q. WHAT IS THE IMPACT OF THE COMPANY'S PROPOSAL TO THE RATE DESIGN IN THIS GRC?

A. This proposal will only apply to new NEM customers, so there is no impact to the Company's proposed rate design in this proceeding. In future GRCs, billing determinants for new NEM customers taking service under the NMR-2025 rate rider will be combined with all other NEM customers from their respective rate schedules for the purposes of cost of service and rate design.

63. Q. HOW MUCH OF THE AB405 REGULATORY ASSET SHORTFALL IS ADDRESSED BY THE IMPLEMENTATION OF 15-MINUTE NETTING?

A. As discussed previously in my Q&A 26, the AB405 regulatory asset reflected the shortfall created by a customer transitioning to NEM service in between GRCs. Enacting a change from monthly netting to 15-minute netting will reduce the amount of the revenue shortfall that previously would have been reflected in the regulatory asset. By reducing the amount of NEM excess energy that is credited at the full retail rate of energy, approximately $247 (48.6 percent) of the $508 total regulatory asset shortfall per customer per year would be addressed, based upon currently effective rates and the usage and generation data from the average existing RS-NEM customer.

64. Q. WILL 15-MINUTE NETTING CAUSE AN OFFSETTING IMPACT TO THE BTER?

A. Yes, as discussed in Q&As 58 and 59 above, the implementation of 15-minute netting will mean that more NEM excess energy kWh will be purchased by the Company, which is passed through the BTER mechanism. As shown **in Table Bohrman Direct-2**, this energy is purchased at a premium to what the actual value would be either on the margin or when compared to utility-scale solar production. This premium is ensured by statute, so it is not something that can be addressed in a regulatory proceeding. The estimated net impact of the move to 15-minute netting, taking into account the additional excess energy and additional contributions toward BTER and deferred energy recovery, is approximately $111 per customer, per year, based upon the average NMR-405 Tier 4 customer. On the other hand, the additional amount that the same average NMR-405 Tier 4 customer will contribute toward BTGR revenue when rates are reset in the subsequent GRC would be approximately $247 per customer per year. Therefore, this proposal would result in a net benefit to all other customers of roughly $136 per NMR-2025 customer per year.

65. Q. WHEN DOES THE COMPANY PROPOSE THE DETERMINATION FOR NEW NEM CUSTOMERS TO BE SET?

A. The Company proposes this mechanism be put in place as soon as possible. Understanding the timing of this proceeding, the cut-off date for NMR-405 and implementation date for determining eligibility for the new NMR-2025 rate rider tariff should be October 1, 2025. By enacting this mechanism as soon as possible, the Commission can take steps right away to limit the excess shortfall that has been and will continue to be accrued by both the Company and other non-NEM customers.

VI. RECOMMENDATIONS AND CONCLUSION

66. Q. PLEASE SUMMARIZE YOUR TESTIMONY AND YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I am supporting the Company's proposed rate design in this GRC proceeding, including a recommended revenue increase cap to the RS class and a proposed daily demand charge for residential and small commercial customers. I also discuss the Company's low-income discount rate that was presented in this filing to fulfill the Commission's directive. Finally, I support the proposal of a 15-minute netting mechanism for new NEM customers beginning with the rate-effective period of this filing.

67. 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 twenty 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, 24-03003, 24-03004, 24-03005

<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