26-05007

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BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2026 Joint Integrated Resource Plan (2027-2046)
Docket No. 26-05007

Prepared Rebuttal Testimony of
Timothy Pollard
Phase III

I. INTRODUCTION AND PURPOSE

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

A. My name is Tim Pollard. My current position is Director of Load Forecasting, Research and Analytics in the Resource Planning and Analysis department for Nevada Power Company d/b/a NV Energy ("Nevada Power") 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 the Companies.

2. Q. DID YOU PREVIOUSLY SUBMIT TESTIMONY IN THIS PROCEEDING?

A. Yes, I filed prepared direct testimony on May 6, 2026, in this 2026 Joint Integrated Resource Plan ("2026 IRP") proceeding. My qualifications were described in Q&A 2 and in **Exhibit Pollard-Direct-1** of my direct testimony.

3. Q. WHAT IS THE PURPOSE OF YOUR PREPARED REBUTTAL TESTIMONY?

A. I respond to the Phase III testimony filed on October 16, 2026, related to the Companies' 2026 IRP load forecast from the following parties:

a. Regulatory Operations Staff ("Staff") witnesses Gavin Clark;

b. Bureau of Consumer Protection ("BCP") witnesses Dale Stransky and Patrick Morton;

c. Advanced Energy United and Southwest Energy Efficiency Project ("AEU/SWEEP") witness Courtney Fieldman;

d. PowerHouse Britain, LLC ("PowerHouse") witness William McCausland;

e. Prologis L.P. ("Prologis") witness Lee Ye;

f. Redwood Materials Inc. ("Redwood Materials") witness Alex Heard;

g. Reno Power NR I, LLC ("Tract") witness Michael P. Gorman;

h. Sierra Club witness Devi Glick;

i. Boyd Gaming Corporation; Station Casinos, LLC; Venetian Las Vegas Gaming, LLC; Caesars Enterprise Services, LLC, MGM Resorts International, Nevada Resort Association ("NRA"), and Nevada Gold Mines, LLC ("NGM"), (collectively referred to as the "Casinos") witness Scott Mallory;

j. Walmart Inc. ("Walmart") witness Dr. Jaime McGovern; and

k. Western Resource Advocates ("WRA") witnesses Andy Eiden and Zoe Harrold.

I also address testimony from Staff witness Youssef AlSafi and the Casinos' witness David Chairez related to the NRS Chapter 704B eligible load limits and rates to be paid by those customers who choose to elect service from a provider of new electric resources through NRS Chapter 704B for the 2026 Joint IRP's three-year action plan ("Action Plan").

4. Q. WHAT EXHIBITS ARE YOU SPONSORING?

A. I am sponsoring the following Exhibits:

- **Exhibit Pollard-Rebuttal-3** – 2026 IRP 704B Rates.

II. LOAD FORECAST

5. Q. WHAT IS YOUR IMPRESSION OF THE TESTIMONY OF OTHER PARTIES IN THIS PHASE OF THE 2026 IRP PROCEEDING?

A. There is a wide range of recommendations regarding the load forecast in this proceeding. The testimony of other parties largely focuses on the treatment of the primary driver of growth in the 2026 IRP forecast: large-load customer projects. I am not aware of any party recommending changes to any other component of the load forecast.

Staff and BCP recommend conditional approval of the Base Load forecast subject to their recommendations regarding the treatment, mitigation and future reporting requirements of the Major Projects forecast component.[1] Prologis also recommends approval of the Base Load forecast as suitable for long-term planning and as the basis for resource approval in this proceeding.[2] Other parties, such as AEU/SWEEP, the Casinos, Sierra Club, and WRA raise concerns that the load forecast may be overstated when the forecast includes load for projects before additional customer commitments or ratepayer protections are in place.[3] In contrast, other parties, such as PowerHouse, Redwood Materials, and Tract raise the concern that the Base Load forecast may understate the large-load customer projects

[1] Docket No. 26-05007, Phase III Direct Testimony of Gavin Clark at 19, Q&A 26; Docket No. 26-05007, Phase III Direct Testimony of Patrick Morton at 3, Q&A 7.
[2] Docket No. 26-05007, Phase III Direct Testimony of Lee Ye at 10, Q&A 17.
[3] Docket No. 26-05007, Phase III Direct Testimony of Courtney Fieldman at 6-7, Q&A 9; Docket No. 26-05007, Phase III Direct Testimony of Scott S. Mallory at 9, Q&A 14; Docket No. 26-05007, Phase III Direct Testimony of Andy Eiden at 16, Q&A 20; Docket No. 26-05007, Corrected Phase III Direct Testimony of Devi Glick at 13, ll. 6-9.

reflected in line extension agreement ramp schedules, or materialize above those levels included in the planning for generation and energy in the retail load forecast.[4]

It is clear in this proceeding, that the current load forecast approach of relying on large customer load mitigation requires additional considerations to support the proposed magnitude and timing of the growth in investment for generation and energy resources necessary to meet the load needs of these large-load customer projects, without transferring risk or costs to other ratepayers.

Therefore, while parties recommend different approaches regarding mitigation, study-phase projects, and the treatment of large-load customers in the forecast, many of the issues they identify are ultimately related to the level of certainty and customer commitment necessary to support generation and energy resource-planning decisions.

6. Q. HOW DOES THE FORM LARGE LOAD ELECTRIC SERVICE AGREEMENT ("LLESA") ADDRESS THE LOAD-FORECAST CONCERNS DISCUSSED IN THIS PHASE?

A. The form LLESA is intended to convert large-load customer requests into defined financial and contractual commitments that will provide more certain inputs supporting load forecasting and resource planning decisions.[5] The LLESA reduces forecasting uncertainty by requiring defined load ramps that can be used directly in the development of the load forecast to improve the certainty of the load forecast inputs and address planning for generation and energy resources.

[4] Docket No. 26-05007, Phase III Direct Testimony of William McCausland at 5, Q&A 8; Docket No. 26-05007, Phase III Direct Testimony of Alex Heard at 3-4, Q&A 10; Docket No. 26-05007, Phase III Direct Testimony of Michael P. Gorman at 14-15, Q&A 22.

[5] *See* Docket No. 26-05007, Phase II Supplemental Rebuttal Testimony of Shawn Elicegui at 11, Q18; *and* Docket No. 26-05007, Phase II Supplemental Rebuttal Testimony of Janet Wells at 13, Q&A 14.

Under the methodology used for the Base Load forecast in this proceeding, and embedded in prior IRP approvals, the Companies use mitigation for all major projects to estimate the total large-project load reasonably expected to materialize.[6] If the LLESA is approved as proposed in Phase II, only the large-load projects (which are subject to the LLESA applicability) with executed agreements will be reflected in future forecasts. Large load projects with executed LLESAs will be included in the load forecast at the loads committed to in the agreement, thereby increasing the certainty of the inputs used for the load forecast. Large-load projects that do not require an LLESA may be included in the load forecast under the current mitigation methodology.

Accordingly, the mitigation and study-phase issues addressed in this testimony remain relevant to the 2026 IRP, which was prepared under the existing methodology. Going forward, however, an approved LLESA would provide more certain inputs and better align generation and energy resource planning with customer commitments.

7. Q. HOW DO THE PARTIES' POSITIONS IN THIS PHASE OF THE PROCEEDING REFLECT THE ISSUE OF FORECASTING CERTAINTY CONSIDERATIONS IN THE 2026 IRP LOAD FORECAST?

A. Generally, parties discuss two main points within the current load forecast methodology that, in their view, introduce higher levels of uncertainty within the load forecast. First is the current method of using line extension agreement ramp schedules to develop expected loads for the system-wide IRP load forecast, generally referred to as mitigation of agreement loads. Second is the consideration of the projects that do not have signed line extension agreements but are in the

[6] Docket No. 24-05041, December 27, 2024, Order at 190–94, para. 520-27.

earlier engineering study phase ("study-phase") projects. These two issues highlight concerns of other parties about the implications of forecasting uncertainty.[7]

Further, Staff identifies that the load forecast is no longer the limiting factor when it comes to expected loads but is limited rather by the availability of sufficient generation resources, and the associated resulting risks to future customer rates.[8]

8. Q. PLEASE SUMMARIZE THE OBJECTIVE OF THE MITIGATION PROCESS AS IT RELATES TO THE LARGE-LOAD CUSTOMER PROJECT COMPONENT OF THE SYSTEM-WIDE IRP LOAD FORECAST.

A. Due to their individual size and long-term ramping behavior, large-load customer projects are individually forecasted as part of the system-wide load forecast. Rule 9 applicants that may become customers provide load ramp schedules through the line extension agreement process, which identify the Estimated Full Build-Out Project Loads ("EFBPL") requirements to define the transmission and distribution facilities necessary to interconnect the project to the grid. The load forecasting team has historically used this information as an input to develop mitigated hourly loads for these individual projects expected to materialize as part of the system-wide load forecast, which is used as an input into the resource planning process identifying necessary system generation and energy resources within an IRP proceeding. Staff confirms that the mitigation approach is a common utility practice that in "its most simple and intended purpose is to ensure the load forecast balances the risk of over- or under-procuring generation to meet demand."[9]

[7] I.e. Docket No. 26-05007, Phase III Corrected Direct Testimony of Devi Glick at 13.
[8] Docket No. 26-05007, Phase III Direct Testimony of Gavin Clark at 13, Q&A 18.
[9] Docket No. 26-05007, Phase III Direct Testimony of Gavin Clark at 6, Q&A 9.

9. Q. DO THE RECOMMENDATIONS OF OTHER PARTIES CHANGE YOUR VIEW REGARDING THE REASONABLENESS OF THE COMPANIES' CURRENT LOAD FORECAST MITIGATION APPROACH?

A. No. Generally, most parties recognize the need to account for uncertainty in large-load development but question whether the Companies' mitigation methodology within the current approach appropriately addresses the forecasting uncertainty in the current load forecast.

Staff generally supports the use of mitigation as a common planning tool, while recommending improvements and greater standardization of the mitigation methodology going forward.[10] Walmart provides a similar recommendation in that it views the Base Load forecast as a planning resource that provides a "plausible planning range and the scale of potential need."[11] I generally agree with Staff's recommendation for an evaluation of the current methodology and greater standardization of the approach in a future filing. While I am unsure at this time if all of Staff's recommended sub-conditions can be met for use in a future proposed methodology, I do believe that the Companies are not opposed to exploring and discussing with Staff its recommendations and how to implement them moving forward. Further, Staff recommends the Base Load forecast be approved as the most accurate representation available for how load may materialize on the Companies' system.[12]

BCP also recommends conditional approval of the Base Load forecast but qualifies approval depending on whether the LLESA framework is approved and which

[10] *Id.* at 17-18, Q&A 24.
[11] Docket No. 26-05007, Phase III Direct Testimony of Dr. Jaime McGovern at 5, Q&A 11.
[12] Docket No. 26-05007, Phase III Direct Testimony of Gavin Clark at 8, Q&A 11.

customers agree to the LLESA or the interim framework.[13] In addition, BCP provides an analysis that questions whether the mitigation amounts applied, especially for study-stage projects, sufficiently reflect to-date realization amounts from an analysis of study-phase projects included in the 2024 IRP load forecast.[14] Further, BCP recommends that the Companies provide project-level reconciliations and tracking of how actual loads materialize over time in future filings.[15] This recommendation appears to be a reasonable request overall within the current methodology, but may require new considerations depending on the final outcome of the form LLESA.

Other parties, such as AEU/SWEEP, provide testimony suggesting the risk associated with overstatement of anticipated load is significant but do not provide an explanation of why it is reasonable to expect the mitigated forecast is overstating future load, or what would be a more reasonable level of mitigation than that used in the forecast.[16]

Tract criticizes the level and application of the Companies' mitigation methodology and argues that it understates expected large-load growth. However, Tract does not reject mitigation itself. In fact, Tract expressly acknowledges that "[l]oad mitigation is a legitimate statistical planning tool" and further acknowledges that a scenario reflecting all executed line extension agreement load does not mean the Companies should seek approval to build resources to serve 100 percent of that load but rather comprehensively study how additional resources could be added to "flex up" to serve Rule 9 high-voltage distribution ("HVD") agreement levels.[17] The

[13] Docket No. 26-05007, Phase III Direct Testimony of Patrick Morton at 9, Q&A 19.
[14] *Id.* at 5, Q&A 12.
[15] *Id.* at 9, Q&A 18.
[16] Docket No. 26-05007, Phase III Direct Testimony of Courtney Fieldman at 6, Q&A 9.
[17] Docket No. 26-05007, Phase III Revised Direct Testimony of Michael P. Gorman at 32, Q&A 31.

Companies' use of alternative forecast scenarios, such as the Base Plus Load Forecast, provide that type of planning information without treating the full line extension agreement ramps as the expected Base Load forecast. Tract's conclusions reinforce the Companies' position that the relevant issue is not whether uncertainty should be reflected in the load forecast, but how that uncertainty should reasonably be quantified under the current methodology.

Redwood Materials provides testimony arguing that it has a contractual entitlement to be served at the load ramp identified in its line extension agreement and seems to oppose using the mitigation approach as a planning tool.[18] This amounts to a position that the correct forecast to use for planning mitigates none of the Rule 9 load and that the full line extension agreement ramp schedule levels are included in the load forecast. However, as addressed below, it is the Companies' historical experience that the requested load ramp is not materializing as contemplated in the line extension agreements. PowerHouse Reno moves load forecasting uncertainty a step further and argues that, even without a line extension agreement, a potential Rule 9 applicant's load should be fully reflected in the load forecast based on factors such as study agreements, site control and easements.[19]

10. Q. BCP PROVIDES AN ANALYSIS REGARDING HISTORICAL OUTCOMES FROM THE 2024 IRP LOAD FORECAST OF THE COMPANIES' MITIGATION APPROACH. WHAT DOES BCP'S ANALYSIS DEMONSTRATE?

A. The analysis presents results showing that despite the Companies' mitigation approach in the 2024 IRP, the load for the considered large-load projects did not

[18] Docket No. 26-05007, Phase III Direct Testimony of Alex Heard at 3, Q&A 10.
[19] Docket No. 26-05007, Phase III Direct Testimony of William McCausland at 5, Q&A 8.

fully materialize to the levels for 2023 through 2025. As noted by BCP, the loads materialized at rates of 87.5 percent for signed projects and 3 percent for study-phase projects over the 2023 to 2025 period.[20] The information echoes the Phase II supplemental rebuttal testimony by Companies' witness Janet Wells, who stated:

> Where actual load has not reached even a mitigated ramp, the resulting gap further supports requiring customers whose requested loads are included in planning to make meaningful financial and contractual commitments addressing the risk that the load is delayed or does not materialize. The applicability of the Form LLESA should therefore reflect not only the magnitude of a customer's request, but also the uncertainty associated with the proposed ramp and the commitments offered to support it.[21]

While actual loads for both signed and study-phase projects have been lower than the levels included in the load forecast, BCP's analysis shows that the mitigation process results in lower variances between forecasts and actual loads than if the full line extension agreement ramp schedule amounts were directly included in the load forecast. In total, the analysis shows that the variance in realized loads from line extension agreement ramp schedule amounts during this period would have been greater at 62 percent for signed projects and one percent of study-phase projects in the 2024 IRP forecast. The results counter Tract's contention that the load forecast has historically understated load and demonstrate the risk of relying on full line extension agreement ramp schedules (or even lesser commitment factors) for generation and energy resource planning, as advocated by PowerHouse and Redwood Materials.[22]

[20] Docket No. 26-05007, Phase III Direct Testimony of Patrick Morton at 6, Q&A 13.
[21] Docket No. 26-05007, Phase II Supplemental Rebuttal Testimony of Janet Wells at 29, Q&A 27.
[22] Docket No. 26-05007, Phase III Revised Direct Testimony of Michael P. Gorman at 31-32, Q&A 31; Docket No. 26-05007, Phase III Prepared Direct Testimony of McCausland at 5, Q&A 8; Docket No. 26-05007, Phase III Direct Testimony of Alex Heard at 3–4, Q&A 10.

This perspective is shared by BCP which, based on its review of actual and load forecast data for Redwood Materials and EdgeCore, finds the mitigated levels for each customer as reasonable.[23] BCP recommends the mitigated levels as preferred over Staff's Phase II proposal to include the full unmitigated line extension agreement ramp schedules for these two customers as part of the Base Minus load forecast.[24]

11. Q. SHOULD PROJECTS BE CONSIDERED AT UNMITIGATED LEVELS WITHIN THE CURRENT LOAD FORECAST METHODOLOGY?

A. No, unless the customer has a signed energy service agreement. For example, as identified in the Casinos' testimony, one project with a signed Framework agreement has been incorporated into the Base Load forecast at levels stated in the agreement.[25] Based on historical data, including BCP's filed analysis, incorporating unmitigated line extension agreement ramp schedules, without an energy services agreement in place, would overstate the loads that the Companies expect to serve and identify additional incremental generation resources that would be built but not be required to serve actual load on the system. This concern may be alleviated if the Commission approves an energy supply agreement, similar to the LLESA, but without Commission approval of such an agreement the Companies can only rely on historical practices and experience supporting the current mitigation approach for projects without a signed energy services agreement.

[23] Docket No. 26-05007, Phase III Direct Testimony of Dale Stransky at 16, Q&A 19.
[24] *Id.*
[25] Docket No. 26-05007, Phase III Direct Testimony of Scott Mallory at 6, Q&A 10.

12. Q. TRACT QUESTIONS THE COMPANIES' MITIGATION METHODOLOGY. DO YOU AGREE WITH TRACT'S CONCLUSIONS?

A. No. Tract raises three principal concerns: (1) certain minimum-use requirements in Tract's line extension agreements are higher than the loads reflected in the Base Load forecast; (2) the methodology does not sufficiently recognize customer performance; and (3) that customer-specific mitigation criteria introduce subjective judgment.[26] These concerns do not demonstrate that the concept of mitigation is unreasonable or that the full line extension agreement ramp is a more accurate forecast of expected load.

To appropriately address Tract's contentions, it is important to contextualize Tract's role in a project/load development cycle. Tract refers to the load under its two Rule 9 Master Planned Community Umbrella Line Extension Agreements as "customer load."[27] However, "Tract is not an end-use customer taking bundled retail electric service."[28] Tract is a master planned community ("MPC") developer that identifies and prepares sites capable of supporting large-scale digital infrastructure.[29] "Tract's sites host present and prospective end-use customers …."[30] Thus, I will not characterize or refer to the load ramps identified under Tract's MPC Umbrella Agreements as customer load.

The first of the three criticisms from Tract conflates two different purposes. A line extension agreement ramp provides information used in planning the transmission and distribution facilities necessary to interconnect the requested load as supported by Jimmy Daghlian. The hourly IRP system-wide load forecast performs a different

[26] Docket No. 26-05007, Revised Direct Testimony of Michael P. Gorman at 29, Q&A 28.
[27] *See, e.g., Id.* at 3, Q&A 5.
[28] *Id.*
[29] *Id.* at 1.
[30] *Id.* at 3, Q&A 5.

function. It estimates the amount and timing of load reasonably expected to materialize for purposes of long-term system planning of generation and energy resources. Thus, a line extension agreement contractual ramp or minimum-use provision does not, by itself, establish that the same amount should be incorporated into the system-wide load forecast.

Second, the Companies' load forecast mitigation methodology specifically attempts to evaluate applicant-specific information and project progression in developing expected loads. That necessarily requires judgment because in the Companies' historical experience, large projects do not all have the same development status, timing, characteristics, or probability of reaching their requested load levels on the requested schedule. Applying project-specific mitigation results to projects with different circumstances does not, by itself, establish that the methodology is inconsistent.

Finally, as discussed above, the BCP analysis shows that actual loads for the projects it reviewed remained below even the mitigated forecast levels during the period analyzed. That result supports maintaining consideration of uncertainty in the load forecast rather than assuming that requested ramps will materialize exactly as requested. Doing so helps to mitigate the forecasting uncertainty of potential over-procurement that may occur if the Companies planned for loads at the line extension agreement ramp schedule levels.

13. Q. DO YOU AGREE WITH TRACT THAT MITIGATING THE LOAD FORECAST FAILS TO ADDRESS RELIABILITY RISK?

A. No. I disagree with the implication that eliminating mitigation would resolve reliability risk. Using the full requested load does not eliminate uncertainty regarding whether, when, or at what level individual projects ultimately materialize. The recommendation simply assumes that every requested load will materialize according to the customer's requested schedule, which has not historically occurred.

The appropriate planning approach must recognize all uncertainty: the risk of insufficient resources if load develops above expectations and the risk of unnecessary or premature investment if requested load is delayed, reduced, or does not materialize. The Companies address these risks by developing a reasonable expected-load forecast and providing alternative scenarios that inform the Commission of the potential consequences if large load develops differently than forecast.[31] Further, in this proceeding, the Companies have provided the LLESA forecast scenario identifying an alternative scenario in which five customers have signed nine LLESA agreements, including ramp schedules and minimum billing requirements, at load levels that when added to the Base Minus Load Forecast, support the Companies' Preferred Plan.[32] Going forward, a form LLESA would further reduce the uncertainty underlying the forecast by connecting large-load project requests to commitments. In my view, that is a more balanced and sober solution than simply assuming that every requested line extension agreement will materialize as originally requested.

[31] Docket 26-05007, Volume 7, Load Forecast Narrative, at 18-20 of 259.
[32] Docket 26-05007, NV Energy June 4, 2026 Supplemental Filing.

14. Q. WILL APPROVAL OF THE FORM LLESA ELIMINATE THE NEED FOR MITIGATION IN FUTURE FILINGS?

A. Not entirely. The Form LLESA would reduce reliance on mitigation for the applicable customer requests by providing load levels committed to through the proposed LLESA. This approach would reduce the application of mitigation and whether to consider study-phase projects as part of the Base Load forecast. But, not all Major Projects would be applicable to the proposed LLESA. Those customers who are under the 25 MW threshold are not proposed to require an LLESA. The Companies may therefore continue to include mitigation considerations in the load forecast for projects that do not contain the commitments in the LLESA.

15. Q. DO YOU AGREE WITH TESTIMONY OF OTHER PARTIES RELATED TO FORECASTING CERTAINTY AND THE INCLUSION OF STUDY-PHASE PROJECTS INTO THE LOAD FORECAST?

A. No. AEU/SWEEP, Sierra Club, and WRA raise concerns regarding the uncertainty associated with study-phase and other less-committed loads and recommend additional protections or more conservative treatment before those loads are relied upon for resource-planning decisions.[33] BCP recommends conditional approval of the Base Load forecast but also views the inclusion of study-phase projects as more speculative and introducing unnecessary uncertainty to the load forecast.[34]

Walmart accepts the mitigated Base Load forecast for planning purposes but recommends stronger customer commitments before the forecast is used to support

[33] Docket No. 26-05007, Phase III Direct Testimony of Courtney Fieldman at 6-7, Q&A 9; Docket No. 26-05007, Corrected Phase III Direct Testimony of Devi Glick on behalf of Sierra Club, at 13, ll. 6-9; Docket No. 26-05007, Phase III Direct Testimony of Andy Eiden at 16, Q&A 21; Docket No. 26-05007, Phase III Direct Testimony of Zoe Harrold at 17-18, Q&As 19-20.

[34] Docket No. 26-05007, Phase III Direct Testimony of Patrick Morton at 3, Q&A 7.

irreversible resource investments.[35] WRA takes a more conservative position and argues that mitigation alone does not sufficiently address the risk associated with uncommitted large loads and recommends that the lower Base Minus forecast (which excludes new or expanding large data center projects) is approved for the resource procurement decision within this proceeding.[36]

In my view, these recommendations primarily address resource-planning risk rather than forecast accuracy. The testimony in this proceeding demonstrates both sides of this uncertainty when considering study-phase projects for the load forecast. Some parties focus primarily on the risk that large-load growth may not materialize as forecast, while others are concerned that the Companies may understate future load growth and fail to procure sufficient resources. The Companies' approach of considering and significantly mitigating study-phase projects, approved by the Commission in the 2024 IRP, is a valid and reasonable approach within the current load forecast methodology to consider all available information in the development of a long-term planning load forecast.[37] This is especially pertinent in this proceeding as, by 2036, 28 study-phase projects, representing 11.2 GW of line extension projects, are included at approximately 1.9 GW of load in the Base Load forecast.

BCP identifies that, due to the growing magnitude of load that is expected from these projects over time, even at heavily mitigated levels, these study-phase projects account for significant non-coincident peak load growth over time and represent 31.2 percent of total system growth by 2046.[38] Simply ignoring this potential load

[35] Docket No. 26-05007, Phase III Direct Testimony of Dr. Jaime McGovern at 5-6 and 15, Q&As 12 and 34.
[36] Docket No. 26-05007, Phase III Direct Testimony of Andy Eiden at 16, Q&A 21.
[37] Docket No. 24-05041, December 27, 2024, Order at 192, para. 526.
[38] Docket No. 26-05007, Phase III Direct Testimony of Patrick Morton at 1 of PAM-5.

limits the ability of the Commission to consider the magnitude of the impact that these large number of future projects is expected to have on the system-wide load forecast.

16. Q. DO YOU AGREE WITH WALMART'S RECOMMENDATION REQUIRING ADDITIONAL TIERED SCENARIOS?

A. No. However, I generally agree with the concept that an incremental scenario of providing information under Walmart's proposed Committed Load Case ("CLC") scenario, in which only projects with energy service, or equivalent, agreements in place are included in a load forecast scenario, could provide valuable information.[39] This scenario is also discussed by BCP, which "can be seen in the graphs [PAM-2 through PAM-4] by looking at the difference between the base and the base signed mitigated only lines."[40] I do, however, view the proposal requiring tiered scenarios proposed by Walmart as unnecessary and disagree with its recommendation for incremental tiered forecasts between the Base Minus and a CLC scenario. All agreements in the proposed CLC are considered signed so there is no justification for trying to separate agreements into different groups. Separating out by tiers would require additional subjective judgment and decisions to identify which agreements may or may not be included in each tier/bucket for the sake of additional incremental scenarios. It is unclear how the tiered results would be used, other than simply information to be presented as general proxies of certainty within the load forecast. Therefore, the additional scenarios are simply not necessary. The Companies already present a range of scenarios, including Base Minus, Base Load, and LLESA-related analyses, that illustrate the implications of different levels of

[39] Docket No. 26-05007, Phase III Direct Testimony of Dr. Jaime McGovern at 6, Q&A 12.
[40] Docket No. 26-05007, Phase III Direct Testimony of Patrick Morton at 3, Q&A 6.

large-load development without requiring numerous additional intermediate forecast scenarios.

17. Q. PLEASE EXPLAIN THE CALCULATION ERROR IDENTIFIED IN THE COMPANIES' RESPONSE TO STAFF DATA REQUEST 190 AND ITS IMPACT ON THE BASE LOAD FORECAST.

A. Staff provides testimony, and estimated impact, regarding a calculation error identified in the Companies' response to Staff Data Request 190,[41] which is also identified by Sierra Club.[42] The Companies also worked to quantify the overall magnitude of the error and achieved results similar to those as presented by Staff for individual projects. However, to determine the total impact to the Base Load forecast, it is necessary to consider study-phase projects and the annual adjustment included in the calculations after a project's EFBPL is reached in the line extension agreement ramp schedule but the forecast has not yet achieved this level of load. This adjustment assumes that the project will increase their load over the remaining years of the forecast period to reach this level. Once reached, it is held constant for any remaining years of the forecast. Further, the Companies' calculations maintain manual adjustments for two customers currently in service, reflecting each customer's actual historical usage.

The resulting change to the Base Load forecast is limited overall, as the average change through 2036 at Nevada Power is a decrease of -306 MW, which is partially offset by an average increase of 73 MW at Sierra. For the action plan period, the net impact includes decreases of -56 MW in 2027, -104 MW in 2028, and -219 MW in 2029. While the error should be corrected, its magnitude does not change my

[41] Docket No. 26-05007, Phase III Direct Testimony of Gavin Clark at 8, Q&A 12.
[42] Docket No. 26-05007, Phase III Corrected Direct Testimony of Devi Glick at 10, ll. 17-18.

overall conclusion that the Base Load forecast provides a reasonable mid-range forecast for purposes of this IRP. Please see the testimony of Shawn Elicegui for the Companies' proposed reconciliation of the load forecast to the Preferred Plan resources.

18. Q. DO YOU AGREE WITH PARTIES' RECOMMENDATIONS FOR ADDITIONAL REPORTING REQUIREMENTS REGARDING THE LOAD FORECAST FOR FUTURE FILINGS?

A. Generally, yes. In the 2026 IRP, the Companies provided detailed information to describe and support the methodology and results for the load forecast. Based on recommendations and comments from Staff, BCP and the Sierra Club, the Companies will assess including additional information for future filings to provide more details on the mitigation approach and how individual projects have materialized relative to the forecast included in the previous IRP filing. I do not disagree that this would be useful information to incorporate into future filings.

Regarding Staff's recommendation of possible changes to the mitigation methodology, the Companies reviewed information provided by Staff and attempted to learn more about other mitigation methods used by other utilities. Based on the materials the Companies were able to review, I agree that a review of alternative mitigation methodologies is worthwhile. I also agree that additional reporting and analysis of major project mitigation in the next IRP, to the extent it is used for the load forecast, would be helpful.

19. Q. HOW DO YOU RESPOND TO POWERHOUSE'S TESTIMONY ASSERTING THAT THE INFORMATION USED FOR THE 2026 IRP DOES NOT MATCH INFORMATION IT PROVIDED THE COMPANIES?[43]

A. PowerHouse has not yet signed a line extension agreement; thus the associated transmission and distribution infrastructure will not be in service in accordance with PowerHouse's anticipated ramp schedule. This scheduling conflict was communicated to the customer in May 2025. The overall ramp schedules for the customer's project were delayed until 2031, and is the same information reflected in the Base Load forecast.

20. Q. CAN YOU PLEASE ADDRESS POSSIBLE MISUNDERSTANDINGS OF YOUR TESTIMONY IDENTIFIED IN TRACT'S TESTIMONY?

A. Yes. There are two examples. First, Tract characterizes the approximately 62 percent value presented in Table Pollard-Direct-8 and the approximately 53 percent value provided in response to Staff Data Request 46 as a "meaningful discrepancy."[44] There is no discrepancy. The proportion of requested load incorporated into the forecast is not constant throughout the forecast period because individual projects have different ramp schedules and expected development trajectories. The figures describe different time periods.

For example, Table Pollard-Direct-8 presents mitigated and unmitigated major project peak demand across the forecast period, and the approximately 62 percent figure cited by Tract is the relationship shown for 2036. The value provided in Staff Data Request 46 addresses an approximate average percentage over the forecast

[43] Docket No. 26-05007, Phase III Revised Direct Testimony of William McCausland at 6, Q&A 10.
[44] Docket No. 26-05007, Phase III Revised Direct Testimony of Michael P. Gorman at 14, Q&A 13.

period relative to the total line agreement capacity requested by these projects. Comparing percentages associated with different years therefore does not establish an inconsistency in the load forecast.

Second, Tract uses my direct testimony regarding more than 5,500 MW of increased requested capacity after completion of the 2026 IRP Load Forecast to support its conclusion that the Companies have under-forecasted large-load growth. That is not what this information demonstrates. My direct testimony explains that the load forecast is an early input into the IRP process and, once finalized, must remain fixed so that it can be used in the subsequent planning analyses. After the forecast was completed, four projects signed line extension agreements and 12 additional projects were submitted for study. The 5,500 MW identified in my testimony represents the combined impact of those subsequent updates to requested capacity. It does not represent actual load exceeding forecast load nor a shortfall in the load forecast approach.

Accordingly, subsequent increases in customer-requested capacity are not evidence that the referenced mitigation methodology understated the load expected from projects known when the forecast was finalized. They demonstrate that the underlying customer information continued to change after the forecast was completed. That distinction is important because Tract relies on those subsequent updates as part of its argument that the "root of the problem is in the load forecasting itself."[45]

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[45] *Id.* at 28, Q&A 27.

21. Q. WHAT IS YOUR OVERALL RECOMMENDATION TO THE COMMISSION REGARDING THE 2026 IRP LOAD FORECAST?

A. Overall, the Companies' request the Commission approve the Base Load forecast as developed using substantially accurate information available when the forecast was finalized, is adequately demonstrated and defended, and adequately documented and justified by, among other things, Large Load Electric Service agreements, and is suitable for making long-term planning decisions over the 2027 to 2046 period.

II. 704B LOAD LIMITS AND RATES

22. Q. WHAT PARTIES MADE RECOMMENDATIONS RELATED TO THE 704B ELIGIBLE LOAD LIMITS AND RATES THAT ARE TO BE SET IN THIS PROCEEDING?

A. Staff recommends approval of the Companies' proposed eligible load limits and rates for 704B eligible customers seeking to exit bundled service during the three-year action plan period.[46] Further, Staff recommends that the Commission order the Companies to file updated items related to the 704B eligible load limits and rates if there are material changes to large load customer growth or other load related factors as a compliance item.[47] The Casinos recommend changes to both the eligible load limits and rates, which I rebut below.[48]

23. Q. DO YOU AGREE WITH THE CASINOS' RECOMMENDATIONS REGARDING THE PROPOSED 704B LOAD LIMITS?

A. No. The Casinos assume that, because Section 7(6) of LCB File No. R195-22 does not expressly reference excluded sales, all sales associated with large commercial

[46] Docket No. 26-05007, Phase III Direct Testimony of Youssef AlSafi at 1-3, Q&A 4 and at 5, Q&A 9.
[47] Docket No. 26-05007, Phase III Direct Testimony of Youssef AlSafi at 5-6, Q&A 9.
[48] Docket No. 26-05007, Phase III Direct Testimony of David S. Chairez at 3, Q&A 5.

and industrial customers must be treated as standard bundled load growth. However, those provisions establish the framework for determining annual eligible-load limits; they do not prescribe the specific forecasting methodology used to determine projected large commercial and industrial load growth. Nor do they require customers served under specialized tariff arrangements to be treated identically to traditional bundled-service customers for forecasting purposes.

The existing 704B framework excludes these sales because the underlying customers are not situated the same as traditional bundled-service customers. The purpose of that framework is to allow eligible load growth to replace customers who depart bundled service during the Action Plan period while holding remaining customers harmless.

24. Q. DO YOU AGREE WITH THE CASINOS' PROPOSED ADJUSTMENT TO THE SALES EXCLUDED FROM THE 704B ELIGIBLE LOAD LIMIT CALCULATIONS?

A. No. The Casinos' proposed adjustment assumes that customers who take service under specialized tariffs, including MPE, LCMPE, and EDRR, should be treated the same as traditional bundled-service customers for purposes of determining eligible-load growth because they continue to pay certain rate components, such as distribution rates.[49] The Casinos' testimony applies a single class-level revenue allocation factor from the LGS-3P rate class to a diverse group of customers and tariff structures to develop an 81.1 percent adjustment to excluded sales, based on total class revenue excluding distribution revenue.

In doing so, the approach uses a revenue-based allocation as a proxy for customer load growth. The resulting factor is derived from a revenue-allocation study rather

[49] *Id.* at 11, Q&A 15.

than from customer characteristics. As a result, it does not measure projected load growth, customer-specific cost responsibility, or the manner in which customers under specialized tariff arrangements contribute to bundled-service costs. The fact that a customer pays certain charges does not, by itself, establish that the customer's sales should be treated as standard bundled load growth. Accordingly, the Casinos' proposal does not provide a logical or reasonable basis for modifying the eligible-load calculation.

The Companies' methodology accounts for the material differences between customers served under specialized tariff arrangements and traditional bundled-service customers. Accordingly, the Companies' methodology provides a more reasonable basis for determining the eligible-load limit. Removing that exclusion would create a mismatch between the treatment of customers remaining on specialized tariffs and the customers whose departing load is being replaced through the eligible-load growth calculation, thereby undermining the objective of holding remaining customers harmless. Staff independently reviewed the proposed annual limits and recommended approval of the Companies' proposed 6.7 MW and 58,982 MWh annual limit.[50] Staff's recommendation does not align with the Casinos' claim that the Companies' methodology is inconsistent with the applicable regulations.

25. Q. DO YOU AGREE WITH STAFF'S RECOMMENDATION THAT THE 704B CALCULATIONS SHOULD BE UPDATED TO REFLECT MATERIAL LOAD-RELATED CHANGES APPROVED BY THE COMMISSION IN THIS PROCEEDING?

A. Yes, I believe this is a reasonable recommendation.

[50] Docket No. 26-05007, Phase III Direct Testimony of Youssef AlSafi at 5, Q&A 9.

26. Q. DO YOU AGREE WITH THE CASINOS' NET BASE TARIFF ENERGY RATE ("NET-BTER") CALCULATION PROPOSAL?[51]

A. In part. I agree with the Casinos' proposed change based on their interpretation of Section 4 as requiring the Net-BTER calculation to be based solely on the modeled difference in system costs between the Base Case and Change Case production-cost modeling scenarios. But, I disagree with the Casinos' implementation, as the average system cost components are incorrectly removed from the calculations.

27. Q. WHY DO YOU NOT AGREE WITH THE CASINOS' RESULTING NET-BTER CALCULATION?

A. While the Casinos propose that the calculation exclude the average system cost impact within the Companies' Net-BTER calculation for the overall system impact of the exiting loads, the proposal incorrectly implements their proposed revisions.[52] Instead of simply deleting the average system cost from the calculations as the Casinos implement, a revised Net-BTER following the Casinos' proposal should be calculated as follows. The cost change should be calculated as the MWh of eligible load (row 23) multiplied by the $/MWh Change in Cost (row 21), including the Mill Tax adjustment.[53] The sum of this difference (row 24) results in $3.953 million from the calculations, rather than $4,000 as incorrectly calculated by the Casinos. This results in a Net-BTER of $0.02780, and an overall net-BTER neutrality rate of $32.42 per MWh. The resulting rates and modified calculations are included in **Exhibit-Pollard-Rebuttal-3**.

[51] The Net-BTER is also referred to as the Net Differential Energy Rate (NDER).
[52] Docket No 26-05007, Phase III Direct Testimony of David S. Chairez at 19, Q&A 23.
[53] *Id.*

28. Q. WHAT IS YOUR RECOMMENDATION IN LIGHT OF THE RECALCULATION DESCRIBED ABOVE?

A. The Casinos' correctly identify the Net-BTER calculation but present an incorrect implementation, thereby understating the Net-BTER rate to be paid by those customers who choose to elect service from a provider of new electric resources through NRS Chapter 704B for the Action Plan period. The Commission should approve the modified rates presented in **Exhibit-Pollard-Rebuttal-3**.

29. Q. THE CASINOS RECOMMEND THAT THE COMMISSION APPROVE A DEVIATION FROM SECTION 12 OF LCB FILE NO. R195-22 OR PROVIDE CLARIFICATION THAT ELIGIBLE 704B CUSTOMERS WILL NOT BE REQUIRED TO PAY THE SAME RATES TWICE THAT ARE INCLUDED IN BOTH THEIR DISTRIBUTION-ONLY SERVICE TARIFF AND THEIR OTHERWISE APPLICABLE BUNDLED TARIFF DURING THEIR TRANSITION.[54] HOW DO YOU RESPOND?

A. The scope of this IRP proceeding with regard to NRS 704B is limited to determination of eligible annual load limits, Net-BTER and variable operations and maintenance ("O&M") credit. The Casinos' request for deviation from the regulation may be raised in their respective 704B individual application dockets.

30. Q. DOES THIS CONCLUDE YOUR PREPARED REBUTTAL TESTIMONY?

A. Yes.

[54] Docket No. 26-05007, Phase III Prepared Direct Testimony of David Chairez at 22-24, Q&As 28-34.

EXHIBIT POLLARD-REBUTTAL-3

Nevada Power Rate Summary

Line No.	Rate	Value	Notes	Source	Line No.
8	Fuel & Purchased Power (BTER) Charges				8
9	R-BTER	$ 0.00463	Current R-BTER	Docket No. 26-05013	9
10	Net BTER	$ 0.02780	Calculations on pg. 2	PLEXOUT	10
11	Variable O&M Credit	$ (0.00001)	Calculations on pg. 3	PLEXOUT	11
12					12
13	Public Policy Rates	(1)	As applicable	Statement of Rates	13
14	Decommissioning and Remediation Charges	As applicable	As applicable		14
15	Regulatory Asset Charges	As applicable	As applicable		15
16	1) Eligible customers will pay public policy program rates of the applicable schedule as detailed on the current Statement of Rates.				16
17					17
18					18
19	Action Period MWh Eligible for 704B Process	118,099			19
20	Revenue Neutrality BTER Charges	$ 3,829,297			20
21	Effective BTER neutrality charge per MWh	$ 32.42			21
22					22

Line No.	Step	Description	2027-2029 period average January	February	March	April	May	June	July	August	September	October	November	December	Total	Line No.
8																8
9		BTER Impact														9
10		Base Case System Information														10
11		Base Case System Requirements	5,394,699	4,747,664	5,092,627	5,028,195	6,653,171	8,841,992	10,344,128	9,684,165	8,026,136	5,835,770	5,138,152	5,729,595	80,516,296	11
12		System Fuel & Purchased Power Cost	$ 258,545	$ 208,353	$ 168,422	$ 152,439	$ 203,455	$ 309,600	$ 411,772	$ 387,868	$ 281,739	$ 188,196	$ 180,293	$ 256,511	$ 3,007,193	12
13		Average System Cost ($/MWh)	$ 47.93	$ 43.89	$ 33.07	$ 30.32	$ 30.58	$ 35.01	$ 39.81	$ 40.05	$ 35.10	$ 32.25	$ 35.09	$ 44.77	$ 37.35	13
14																14
15		Change Case System Information														15
16		Change Case System Requirements	5,385,489	4,739,233	5,082,945	5,019,398	6,643,137	8,831,167	10,332,442	9,672,431	8,015,260	5,826,337	5,129,598	5,720,760	80,398,196	16
17		System Fuel & Purchased Power Cost	$ 259,257	$ 208,880	$ 167,958	$ 152,603	$ 203,208	$ 309,659	$ 410,999	$ 387,152	$ 281,450	$ 189,503	$ 180,905	$ 257,619	$ 3,009,192	17
18		Average System Cost ($/MWh)	$ 48.14	$ 44.07	$ 33.04	$ 30.40	$ 30.59	$ 35.06	$ 39.78	$ 40.03	$ 35.11	$ 32.53	$ 35.27	$ 45.03	$ 37.43	18
19																19
20		Fuel & Purchased Power Cost Changes	$ 712	$ 527	$ (463)	$ 164	$ (247)	$ 58	$ (772)	$ (716)	$ (289)	$ 1,307	$ 611	$ 1,108	$ 1,999	20
21		$/MWh Change in Cost	$ 0.13	$ 0.11	$ (0.09)	$ 0.03	$ (0.04)	$ 0.01	$ (0.07)	$ (0.07)	$ (0.04)	$ 0.22	$ 0.12	$ 0.19	$ 0.02	21
22																22
23		Eligible MWh Load	9,210	8,432	9,682	8,797	10,034	10,826	11,686	11,734	10,875	9,433	8,555	8,835	118,099	23
24	1	Eligible MWh Load BTER Impact Fee[1]	$ 1,213	$ 933	$ (879)	$ 286	$ (372)	$ 71	$ (870)	$ (866)	$ (390)	$ 2,107	$ 1,016	$ 1,704	$ 3,953	24
25																25
26		R-BTER Adjustment														26
27		Renewable Energy														27
28		Renewable Energy Generation (MWh)	589,882	547,114	649,409	651,832	655,440	601,726	552,149	564,966	541,904	568,909	547,582	587,444	7,058,357	28
29	2a	Renewable Contract Energy Cost	$ 55,412	$ 51,066	$ 59,944	$ 60,470	$ 59,979	$ 54,558	$ 50,347	$ 51,893	$ 49,404	$ 52,578	$ 51,342	$ 55,729	$ 652,720	29
30		Average Renewables Cost	$ 93.94	$ 93.34	$ 92.31	$ 92.77	$ 91.51	$ 90.67	$ 91.18	$ 91.85	$ 91.17	$ 92.42	$ 93.76	$ 94.87	$ 92.47	30
31																31
32		Non-Renewables System Information														32
33		System Requirements	4,804,817	4,200,551	4,443,218	4,376,363	5,997,732	8,240,266	9,791,979	9,119,199	7,484,232	5,266,861	4,590,570	5,142,151	73,457,938	33
34		Total System Cost (exc. Renewables)	$ 203,133	$ 157,287	$ 108,478	$ 91,969	$ 143,476	$ 255,043	$ 361,425	$ 335,975	$ 232,334	$ 135,618	$ 128,951	$ 200,782	$ 2,354,473	34
35		Average Non-Renewable System Cost	$ 42.28	$ 37.44	$ 24.41	$ 21.01	$ 23.92	$ 30.95	$ 36.91	$ 36.84	$ 31.04	$ 25.75	$ 28.09	$ 39.05	$ 32.05	35
36																36
37	2b-c	Renewable Energy @ Ave. System Cost	$ 24,938	$ 20,486	$ 15,855	$ 13,698	$ 15,679	$ 18,624	$ 20,380	$ 20,815	$ 16,822	$ 14,649	$ 15,382	$ 22,938	220,267	37
38	2d	R-BTER Cost	$ 30,473	$ 30,579	$ 44,089	$ 46,771	$ 44,300	$ 35,934	$ 29,967	$ 31,078	$ 32,582	$ 37,929	$ 35,960	$ 32,791	$ 432,453	38
39																39
40		Eligible Exiting Load	9,210	8,432	9,682	8,797	10,034	10,826	11,686	11,734	10,875	9,433	8,555	8,835	118,099	40
41		Percent of System Loads	0.171%	0.178%	0.190%	0.175%	0.151%	0.122%	0.113%	0.121%	0.136%	0.162%	0.166%	0.154%	0.147%	41
42																42
43	3	R-BTER costs allocated to Eligible Load	$ 52	$ 54	$ 84	$ 82	$ 67	$ 44	$ 34	$ 38	$ 44	$ 61	$ 60	$ 51	$ 670	43
44																44
45		Net BTER Rate Impact														45
46	4	Cost Difference w/ R-BTER Adjustment	$ 1,161	$ 879	$ (963)	$ 204	$ (439)	$ 27	$ (904)	$ (903)	$ (435)	$ 2,046	$ 956	$ 1,653	$ 3,283	46
47	5	Net-BTER rate	$ 0.12603	$ 0.10423	$ (0.09948)	$ 0.02324	$ (0.04370)	$ 0.00253	$ (0.07734)	$ (0.07699)	$ (0.03996)	$ 0.21691	$ 0.11175	$ 0.18712	$ 0.02780	47
48																48
49		Notes:												**Net-BTER Rate**	**$ 0.02780**	49
50		1) Adjusted for Mill Tax (0.3891035%)														50

NEVADA POWER COMPANY
Variable O&M Charge Calculation

Docket No. 26-05007
2026 IRP
Exhibit Pollard-Rebuttal-3
Page 3 of 3

Line No.		Base Case			Change Case			Difference			Line No.
		MWh	Costs ($000)	$/MWh	MWh	Costs ($000)	$/MWh	MWh	Costs ($000)	$/MWh	
9											9
10	2027										10
11	Jan	1,673,534	$ 3,878	$ 2.32	1,673,534	$ 3,867	$ 2.31	0	$ (11)	$ (0.01)	11
12	Feb	1,449,711	$ 3,386	$ 2.34	1,449,711	$ 3,392	2.34	0	6	0.00	12
13	Mar	1,563,972	$ 3,394	$ 2.17	1,563,972	$ 3,391	2.17	0	(3)	(0.00)	13
14	Apr	1,537,462	$ 2,450	$ 1.59	1,537,462	$ 2,461	1.60	(0)	11	0.01	14
15	May	2,062,063	$ 3,395	$ 1.65	2,062,063	$ 3,382	1.64	(0)	(13)	(0.01)	15
16	Jun	2,778,168	$ 7,799	$ 2.81	2,778,168	$ 7,802	2.81	0	3	0.00	16
17	Jul	3,278,823	$ 10,756	$ 3.28	3,278,823	$ 10,803	3.29	(0)	47	0.01	17
18	Aug	3,061,252	$ 10,120	$ 3.31	3,061,252	$ 10,060	3.29	(0)	(60)	(0.02)	18
19	Sep	2,517,256	$ 6,914	$ 2.75	2,517,256	$ 6,781	2.69	(0)	(132)	(0.05)	19
20	Oct	1,789,913	$ 3,912	$ 2.19	1,789,913	$ 3,925	2.19	(0)	13	0.01	20
21	Nov	1,563,974	$ 3,751	$ 2.40	1,563,974	$ 3,765	2.41	0	14	0.01	21
22	Dec	1,761,405	$ 4,079	$ 2.32	1,761,405	$ 4,077	2.31	0	(2)	(0.00)	22
23											23
24	Total	25,037,533	$ 63,833	$ 2.55	25,037,533	$ 63,705	$ 2.54	(0)	$ (128)	$ (0.01)	24
25											25
26											26
27	2028										27
28	Jan	1,786,819	$ 4,408	$ 2.47	1,782,218	$ 4,359	$ 2.45	(4,601)	$ (49)	$ (0.02)	28
29	Feb	1,608,775	$ 3,824	2.38	1,604,485	$ 3,810	2.37	(4,290)	(14)	(0.00)	29
30	Mar	1,681,506	$ 3,647	2.17	1,676,665	$ 3,640	2.17	(4,841)	(6)	0.00	30
31	Apr	1,667,718	$ 2,884	1.73	1,663,318	$ 2,883	1.73	(4,399)	(1)	0.00	31
32	May	2,213,642	$ 3,610	1.63	2,208,628	$ 3,600	1.63	(5,014)	(10)	(0.00)	32
33	Jun	2,942,663	$ 7,343	2.50	2,937,249	$ 7,376	2.51	(5,414)	33	0.02	33
34	Jul	3,423,447	$ 9,160	2.68	3,417,606	$ 9,081	2.66	(5,841)	(79)	(0.02)	34
35	Aug	3,200,837	$ 8,086	2.53	3,194,970	$ 7,945	2.49	(5,867)	(141)	(0.04)	35
36	Sep	2,636,473	$ 6,072	2.30	2,631,031	$ 6,044	2.30	(5,442)	(28)	(0.01)	36
37	Oct	1,900,758	$ 4,329	2.28	1,896,044	$ 4,378	2.31	(4,714)	49	0.03	37
38	Nov	1,682,278	$ 3,938	2.34	1,677,996	$ 3,931	2.34	(4,282)	(7)	0.00	38
39	Dec	1,874,614	$ 4,501	2.40	1,870,197	$ 4,529	2.42	(4,417)	28	0.02	39
40											40
41	Total	26,619,531	$ 61,802	$ 2.32	26,560,408	$ 61,577	$ 2.32	(59,123)	$ (225)	$ (0.00)	41
42											42
43											43
44	2029										44
45	Jan	1,934,346	$ 5,425	$ 2.80	1,929,737	$ 5,489	$ 2.84	(4,609)	$ 64	$ 0.04	45
46	Feb	1,689,179	$ 4,241	2.51	1,685,037	$ 4,245	2.52	(4,142)	5	0.01	46
47	Mar	1,847,149	$ 4,120	2.23	1,842,308	$ 4,115	2.23	(4,841)	(5)	0.00	47
48	Apr	1,823,015	$ 3,298	1.81	1,818,617	$ 3,346	1.84	(4,398)	48	0.03	48
49	May	2,377,466	$ 4,121	1.73	2,372,446	$ 4,182	1.76	(5,020)	61	0.03	49
50	Jun	3,121,162	$ 7,310	2.34	3,115,750	$ 7,266	2.33	(5,412)	(44)	(0.01)	50
51	Jul	3,641,857	$ 9,004	2.47	3,636,012	$ 8,801	2.42	(5,845)	(203)	(0.05)	51
52	Aug	3,422,076	$ 8,734	2.55	3,416,209	$ 8,560	2.51	(5,867)	(174)	(0.05)	52
53	Sep	2,872,407	$ 6,602	2.30	2,866,973	$ 6,446	2.25	(5,433)	(156)	(0.05)	53
54	Oct	2,145,099	$ 5,548	2.59	2,140,380	$ 5,528	2.58	(4,719)	(20)	(0.00)	54
55	Nov	1,891,900	$ 4,400	2.33	1,887,627	$ 4,443	2.35	(4,273)	43	0.03	55
56	Dec	2,093,576	$ 6,406	3.06	2,089,158	$ 6,523	3.12	(4,418)	117	0.06	56
57											57
58	Total	28,859,232	$ 69,209	$ 2.40	28,800,255	$ 68,945	$ 2.39	(58,977)	$ (263)	$ (0.00)	58
59											59
60	3-year Total	80,516,296	$ 194,844	$ 2.42	80,398,196	$ 194,228	$ 2.42	(118,099)	$ (616)	$ 0.01	60
61	Percent of System Loads								0.147%		61
62	Load ratio share of Variable O&M reduction								$ (1)		62
63											63
64							**Variable O&M credit ($/kWh)**		**$ (0.00001)**		64
65											65

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, TIMOTHY POLLARD, 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: November 2, 2026

Timothy Pollard