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BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their joint 2025-2044 integrated resource plan, for the three year Action Plan period 2025-2027, and the Energy Supply Plan period of 2025-2027.	Docket No. 24-05___

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SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY

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APPLICATION

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

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of NEVADA POWER COMPANY d/b/a NV Energy and SIERRA PACIFIC POWER COMPANY d/b/a NV Energy, seeking approval of their joint 2025-2044 integrated resource plan, for the three year Action Plan period 2025-2027, and the Energy Supply Plan period of 2025-2027.	)	Docket No. 24-05____

APPLICATION TO APPROVE TRIENNIAL INTEGRATED RESOURCE PLAN, THREE YEAR ACTION PLAN AND ENERGY SUPPLY PLAN

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" or "NV Energy") make this Application, pursuant to Nevada Revised Statute ("NRS") § 704.741 *et seq.*, and Nevada Administrative Code ("NAC") § 704.9005 *et seq.* This Application seeks approval by the Public Utilities Commission of Nevada ("Commission") of the Companies' 2025-2044 joint triennial integrated resource plan ("2024 Joint IRP"), the plan of action for the three year period 2025-2027 ("Action Plan"), including their energy supply plan for the three year period 2025-2027 ("2024 ESP"). A triennial IRP must be processed within 210 days of filing pursuant to NRS § 704.751(1)(b), or it is deemed approved as filed. Thus, the "deemed approved" date for the 2024 Joint IRP is December 27, 2024. A triennial energy supply plan ("ESP") must be processed within 135 days of filing pursuant to NRS § 704.751(1)(a). Thus, the "deemed approved" date for the 2024 ESP is October 11, 2024.

I.
SUMMARY AND INTRODUCTION

At the time the Companies filed its joint triennial IRP in 2021, energy markets in the western United States were experiencing significant stress from extreme and prolonged summer heatwaves, a trend that has continued in subsequent years. In August 2020, excessive heat events led the California Independent System Operator ("CAISO") to implement rolling blackouts, which resulted in significant supply curtailments for the Companies. During a similar heat event in July 2021, the Companies experienced an Energy Emergency Alert ("EEA") Level 3 event during near record-breaking temperatures in the region. A wildfire in southern Oregon simultaneously resulted in a loss of transmission capacity and once again, significant supply curtailments for the Companies. In September 2022, the first week of the month proved to be one of the most challenging periods on record for the western electrical grid. The intensity and duration of the September 2022 heat event qualifies it as one of the worst heatwaves to strike the western United States in the past 40 years. During this heatwave, six entities in the western United States issued some level of EEA, and market energy was severely limited as prices climbed to as high as $1,900 per megawatt-hour ("MWh"). In light of these challenging events in recent years, resource adequacy remains a top priority for NV Energy.

The 2024 Joint IRP adds 1,028 megawatts ("MW") of new solar generating facilities, along with 1,028 MW of co-located battery storage, and 411 MW of hydrogen-capable natural gas combustion turbines at the North Valmy Generating Station, creating a balanced approach to providing affordable and reliable energy while addressing the clean energy goals of the state, the Companies, and their customers. The 2024 Joint IRP also contains an update on the Greenlink Nevada transmission project costs and states the reasons why this backbone transmission project, even with the increased budget, remains vital to the state and its energy future. The Plan requests approval for a number of transmission projects necessary to keep pace with Nevada's rapid economic growth. Additionally, the Companies present next steps for joining a regional Day-Ahead Market and the Western Resource Adequacy Program ("WRAP") as well as a roadmap to joining a Regional Transmission Organization ("RTO").

The Companies continue to focus on delivering an affordable and reliable renewable energy future for Nevada with a balanced approach to decarbonization. The Renewable Portfolio Standard ("RPS") continues to ramp up to a requirement of 50 percent renewable energy by 2030. The state also has a goal for an amount of zero carbon generation equal to sales in 2050. Furthermore, customers have been clear that they want more renewable energy and service options to meet their own sustainability goals. Finally, climate change is impacting the western energy markets, requiring the Companies and stakeholders to reevaluate established practices to ensure there is sufficient energy to meet peak energy demands.

To continue addressing these challenges and opportunities, the Companies have prepared this 2024 Joint IRP. The 2024 Joint IRP demonstrates how the Companies intend to address the state's clean energy goals and policies and meet the energy demands of their customers by balancing cost, reliability, and decarbonization goals. After analyzing several energy supply portfolios based on capacity needs, cost to customers, decarbonizing goals, societal cost, economic impact on the state and other factors, the Companies selected the Balanced Plan as their Preferred Plan. The Balanced Plan recommends the addition of three power purchase agreements for solar generating resources totaling more than 1,000 MW, each with co-located battery energy storage systems ("BESS"); two company-owned hydrogen-capable natural gas simple cycle combustion turbines; and transmission infrastructure necessitated by the new resources and to support growing customer demand. In addition, the evolution of the Companies' proposed demand side management plan to provide grid value with a new savings target and the growing maturity of the distributed resource plan and planning processes seek to create foundational strategies to enable flexible load and deploy cost-effective Non-Wires Alternatives to support the needs of the grid and our State, while providing savings to NV Energy customers. To demonstrate the effect on customer rates from the proposed investments, the Companies have conducted and are presenting through this filing numerous rate impact analyses covering the alternative supply plans, demand side plan, and transportation electrification plan.

The Balanced Plan uses the updated load forecast, addresses state and federal carbon policy and changes in fuel and purchase power prices, meets the system's planning reserve margin ("PRM"), meets or exceeds the RPS in every year, and advances the state's 2050 clean energy goal. The Companies' investment in renewable resources in the Balanced Plan pays off with meaningful gains to both the state economy and the environment. The Companies selected the Balanced Plan as it is closely aligned with Nevada's energy policies, delivers the resources its customers value, and represents a balance of cost to customers, reliability, and environmental benefits. NV Energy, therefore, asks that the Commission accept the Balanced Plan and authorize NV Energy to take all necessary steps in the Action Plan period to implement the plan.

II.
THE APPLICANTS

Nevada Power and Sierra are Nevada corporations and wholly-owned subsidiaries of NV Energy, Inc. Nevada Power and Sierra are public utilities as defined in NRS § 704.020 and are subject to the jurisdiction of the Commission. Nevada Power is engaged in providing electric service to the public in portions of Clark and Nye counties, Nevada pursuant to a certificate of public convenience and necessity issued by this Commission. Sierra provides electric service to the public in portions of 14 northern Nevada counties, including the communities of Carson City, Minden, Gardnerville, Reno, Sparks, and Elko. In addition, Sierra owns and operates a certificated local distribution company engaged in the retail sale of natural gas to customers in the Reno-Sparks metropolitan area.

Sierra's primary business office is located at 6100 Neil Road in Reno, Nevada and Nevada Power's primary business office is located at 6226 West Sahara Avenue in Las Vegas, Nevada. All correspondence related to this Application should be transmitted to the Companies' counsel *and* to the Manager of Regulatory Services, as set forth below:

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III.
APPLICATION EXHIBITS

Included with this Application and incorporated herein by reference are the following exhibits:

- **Application Exhibit A** is the three-year Action Plan for the period January 1, 2025, through December 31, 2027. This exhibit is required by NAC § 704.9489.
- **Application Exhibit B** is a roadmap of applicable statutes and regulations and the location of the required information within the filing. This exhibit is not described in or mandated by the Commission's IRP regulations or prior IRP orders but is provided to assist those performing an evaluation of the technical aspects of the filing.
- **Application Exhibit C** is a proposed draft notice of the Application as required by NAC § 703.162.
- **Application Exhibit D** includes Current Tariffs and Schedules superseded by the Proposed Tariffs and Schedules.
- **Application Exhibit E** includes Proposed Tariffs and Schedules.

In addition, as required by NAC § 704.9215, the 2024 Joint IRP contains a stand-alone Summary Volume. Section I of that document contains a short, executive summary of the 2024 Joint IRP. The remainder of the Summary Volume addresses each of the items required by NAC § 704.9215, is written in plain language and includes easily interpretable tables, graphs and maps.

IV.
SUPPORTING MATERIAL

Section 704.9321 of the NAC provides that a utility's resource plan must be based on substantially accurate data, adequately demonstrated and defended, and adequately documented and defended. As is set forth below, included in this 2024 Joint IRP, and incorporated herein by reference, the reader will find all material required to adequately demonstrate and defend the substantially accurate data supporting the analysis and the requests for affirmative relief set forth herein. A summary of this information, which includes narrative, technical appendices,[1] and supporting prepared direct testimony,[2] is set forth by general topic below.

A. Load, Fuel and Purchased Power Forecasts. The first narrative in the 2024 Joint IRP filing addresses load forecasts, includes a comprehensive discussion of market fundamentals that impact long-term fuel and purchased power pricing, and describes and supports the long-term price forecasts for fuel and purchased power that underlie the analysis in the 2024 Joint IRP.

1. Load Forecasting. The narrative addressing the load forecast is supported by the prepared direct testimony of **Tim Pollard,** Director of Load Forecasting, Research and Analytics, as well as the following technical appendices:

- LF-1 - 2024 Joint IRP Load Forecast Technical Appendix (portions of which are confidential);
- LF-2 - State Demographer Long-Term Population Projections, 2022-2041;
- LF-3 - State Demographer 2022 Governor Certified Series – Population Estimates of Nevada's Counties;

[1] NAC § 704.922 requires that a utility's resource plan include technical appendices that contain sufficient detail to enable a technically proficient reader to understand how the resource plan and its forecasts were prepared and to evaluate the validity of the assumptions and the accuracy of the data used, including, without limitation, a list of the major assumptions used, a description of the forecasting methods employed and a description of the software utilized.

[2] NAC § 704.9321(4) requires that all testimony offered in support of a utility's resource plan be filed with the resource plan.

- LF-4 - Las Vegas Convention and Visitors Year to Date executive summary for 2023;
- LF-5 - 2023 CBER Clark County Population Forecast, June 2023;
- LF-6 - S&P Global HIS Economics 2023 (confidential);
- LF-7 - Itron, Inc. Statistically adjusted end-use ("SAE") model overview;
- LF-8 - Applied Analysis reports.

In addition, Mr. Pollard supports the Companies' proposed annual limits for eligible customers to apply for and take service from a provider of new electric resources pursuant to NRS Chapter 704B and the proposed transition rates.

2. ***Market Fundamentals and Fuel and Purchased Power Forecasting.*** The narrative addressing market fundamentals and the fuel and purchased power forecasts is supported by the prepared direct testimony of **Zeljko Vukanovic**, Market Fundamentals Lead. **Vincent Vitiello,** Gas Supply Planning Lead, sponsors the gas transportation strategies.

- FPP-1 - Fuel and Purchased Power Price Forecasts (Confidential)

C. Demand-Side Resources. This narrative in the 2024 Joint IRP addresses the Companies' demand-side management ("DSM") and planning processes, the performance of the Companies' 2023 DSM programs, as well as their current and proposed portfolio of demand-side resources and programs. The narrative addressing demand-side resources is supported by the following technical appendices.[3]

- DSM-01 – AceGuru Technical Manual
- DSM-02 – 2023 Ace Guru Input-Output
- DSM-03 – 2025-2027 Ace Guru Traditional Portfolio Input-Output
- DSM-04 – 2025-2027 Ace Guru Grid Value Portfolio Input-Output
- DSM-05 – Net-to-Gross Study Report
- DSM-06 – Net-to-Gross Study DSM Program Vol 1

[3] In addition, consistent with the Companies' commitment in prior DSM plan proceedings, a set of electronic workpapers supporting the analysis and selection of the programs and measures discussed in the narrative have been developed. The electronic workpapers are not a part of the filing but have been provided to the Commission's Regulatory Operations Staff ("Staff") and the Bureau of Consumer Protection ("BCP").

- DSM-07 – DSM Collaborative Meeting Slides
- DSM-08 – DSM Working Group Meeting Slides
- DSM-09 – DSM Working Group Final Report
- DSM-10 – DSM Collaborative Stakeholder Survey Results
- DSM-11 – M&V Process
- DSM-12 – Technical Approach to the M&V
- DSM-13 – 2023 Energy Education M&V
- DSM-14 – 2023 Energy Reports M&V
- DSM-15 – 2023 Energy Assessments M&V
- DSM-16 – 2023 Home Energy Saver M&V
- DSM-17 – 2023 Residential Codes and New Construction M&V
- DSM-18 – 2023 QAR Low Income M&V
- DSM-19 – 2023 Direct Install M&V
- DSM-20 – 2023 Residential Demand Response M&V
- DSM-21 – 2023 Energy Smart Schools M&V
- DSM-22 – 2023 Business Energy Services M&V
- DSM-23 – 2023 Commercial Demand Response M&V
- DSM-24 – 2023 Program Development Field Trials
- DSM-25 – 2023 Low Income Expenditure Tracking
- DSM-26 – 2025-2027 Market Potential Study
- DSM-27 – DSMore User Manual
- DSM-28 – DSMore User Manual Technical Appendices
- DSM-29 – 2025-2027 DSMore Output Sheets
- DSM-30 – DSM Rate Impact Methodology
- DSM-31 – DSM Rate Impact Model Results
- DSM-32 – Directive 5 Rate Impact

The demand-side resources narrative and the technical appendices supporting the narrative, are sponsored by the prepared direct testimony of the following demand-side planning, implementation and evaluation experts:

Patricia Rodriguez, Director, Energy Services Optimization, sponsors and co-sponsors all portions of the DSM plan along with the following witnesses.

Christopher Belcher, Integrated Energy Services Policy and Compliance Manager, Integrated Energy Services Operations, supports portions of the Demand Side Plan, including aspects of the Demand Side Plan rate impacts.

Lark Lee, Senior Director at Tetra Tech**,** co-sponsors the Net-to-Gross Study in Technical Appendix Items DSM-5 and DSM-6.

Robert Oliver, Principal at ADM Associates, Inc., co-sponsors the M&V reports contained in Technical Appendix Items DSM-2 through DSM-23, and DSM-25.

Dr. Sanem Sergici, Principal at The Brattle Group, sponsors the Demand Side Plan rate impact analyses pertaining to the enhanced Demand Side Plan spending.

Tom Hines, Principal and Co-founder of Tierra Resource Consultants LLC, also supports the DSM market potential study as well as development of Demand Side Plan portfolios.

Dr. Kenneth Skinner, Vice President of Integral Analytics Inc., supports the financial models in the Demand Side Plan.

D. Distributed Resources Plan. The narrative in the 2024 Joint IRP filing addresses the Companies' Distributed Resources Plan ("DRP"). The narrative addressing distributed resources is supported by the following technical appendices:

- DRP-1 Docket No. 21-06001 DRP Stakeholder Process Issues List
- DRP-2 DRP Stakeholder Process Running Meeting Notes
- DRP-3 Nevada Power and Sierra Past Peaks
- DRP-4 Nevada Power and Sierra Forecast Peaks
- DRP-5 NV Energy Forecasting Anywhere Methodology

- DRP-6 Pathway Results
- DRP-7 HCA Monthly Update Internal Process Flowchart
- DRP-8 Clean Energy Programs Post Incentive Installation Survey Data Results
- DRP-9 Energy Storage Systems and System Peak Report

The DRP narrative, and the technical appendices supporting the narrative, are sponsored by the prepared direct testimony of the following planning, implementation and evaluation experts:

Marie Steele, Vice President, Integrated Energy Services, sponsors the Distributed Resources Plan as a policy witness.

Joseph Sinobio, Director of Integrated Grid Planning, sponsors the Distributed Resources Plan as the key technical expert .

Michael Brown, Integrated Energy Services Director, sponsors sections 7.A, 7.B, 8.A.2, and 8.B of the Distributed Resources Plan .

Tyler Meroth, Transmission Planning Engineer, sponsors Section 3.B of the Distributed Resources Plan, Distributed Resources Plan Analyses: Transmission Planning.

Kimberly Williams, Director of Resource Planning and Analysis, supports incorporation of the DRP in the integrated planning process .

The Companies present the Transportation Electrification Plan ("TEP") as part of the DRP. The narrative addressing distributed resources is supported by the following technical appendices:

- TEP-1 Electric Vehicle Charging Data Report
- TEP-2 Stakeholder Working Group Meeting Presentations
- TEP-3 EV Program Offerings Customer Survey
- TEP-4 AG_DSMore Cost-Effective Outputs Inputs
- TEP-5 Stakeholder Survey Results
- TEP-6 AG_DSMore Cost-Effectiveness Comparison

The following witnesses sponsor key aspects of the TEP:

Adam Grant, Director of Integrated Energy Services Operations, sponsors the proposed Transportation Electrification Plan.

Snuller Price, Senior Partner at Energy and Environmental Economics, supports the Distributed Energy Resources ("DER") evaluation framework and NV Energy's market potential study.

Misha Pascal, Regulatory Analysis Lead, supports the Companies' proposal of a Rule 9 allowance mechanism for the facilities required for electric vehicle charging for commercial customers.

E. Supply Plan Resources. This narrative in the 2024 Joint IRP filing addresses the Companies' Supply Plan (including the generation, renewable energy, and transmission plans). Each element of the Supply Plan is addressed in turn below:

1. Conventional Generation. This portion of the Supply Plan is supported by the following technical appendices:

- GEN-1 - Unit Characteristics Table (Confidential)
- GEN-2 – Emissions Rates - Generation
- GEN-3 – Generation Brownfield Study (Confidential)

The conventional Generation of the Supply Plan narrative, as well as the technical appendices supporting it, is sponsored by the prepared direct testimony of the following supply-side resource planning and implementation experts.

John Lescenski, Plant Engineering and Technical Services, sponsors the Generation section of the Supply Plan including the proposed Valmy combustion turbine project .

Mathew Johns, Vice President, Environmental Services and Land Management, supports the environmental regulatory discussion in the Generation section of the Supply Plan

2. Current Renewable Portfolio, Compliance with Renewable Portfolio Plan and New Renewable Resources. These portions of the Supply Plan are found in Section 2.D.

(Renewable Energy Plan) of the Supply Plan narrative. This section of the narrative is supported by the following technical appendices:

- REN-1 2024 IRP Proposed Projects 12x24 Supply Tables
- REN-2 2024 IRP RPS Compliance Build Out Scenarios
- REN-3-DLE(a) Dry Lake East PPA (Redacted)
- REN-3-DLE(b) Dry Lake East Due Diligence Summary
- REN-3-DLE(c) Dry Lake East NAC Compliance
- REN-3-DLE(d) Dry Lake East PPA Key Provisions
- REN-4-BS3(a) Boulder Solar III PPA (Redacted)
- REN-4-BS3(b) Boulder Solar III Due Diligence Summary
- REN-4-BS3(c) Boulder Solar III NAC Compliance
- REN-4-BS3(d) Boulder Solar III PPA Key Provisions
- REN-5-LS(a) Libra PPA (Redacted)
- REN-5-LS(b) Libra Due Diligence Summary
- REN-5-LS(c) Libra NAC Compliance
- REN-5-LS(d) Libra PPA Key Provisions
- REN-6-CS2(a) Corsac Generating Station 2 PPA (Redacted)
- REN-6-CS2(b) Corsac Generating Station 2 Due Diligence Summary
- REN-6-CS2(c) Corsac Generating Station 2 NAC Compliance
- REN-6-CS2(c) Corsac Generating Station 2 PPA Key Provisions
- REN-7 Cost Comparison of Solar Plus Storage RFP Bids to PPA Pricing
- REN-8 Bid Scores Summary 2023 OR RFP

The Renewables section of the Supply Plan narrative and the technical appendices supporting this narrative section are sponsored by the prepared direct testimony of the following witnesses:

Jimmy Daghlian, Vice President of Renewables, sponsors the Companies' Renewables section of the Supply Plan.

Sean Spitzer, Senior Project Manager, Renewable Energy, sponsors the Companies' renewable energy projects to support the Renewables Section of the Supply Plan.

Mark Warden, Director of Development, Renewable Energy and Origination, describes named placeholders and provides status updates on the Companies' renewable initiatives.

Janet Wells, Vice President, Regulatory, supports Energy Supply Agreements ("ESA") used to support large customers' renewable goals.

3. ***Transmission Plan.*** This portion of the Supply Plan is found in Section 2.E (Transmission Plan) of the Supply Plan. The following technical appendices support this section of the narrative:

- TRAN-1 – 2024 IRP Greenlink Nevada
- TRAN-2 – Apex Area Master Plan (2024) Report
- TRAN-3 – Western Nevada Master Plan
- TRAN-4 – Agreements List 2024 IRP

The Transmission Plan narrative, as well as the technical appendices supporting the narrative, are sponsored by the prepared direct testimony of the following witnesses:

Charles Pottey, Director of Transmission Planning, sponsors the Transmission Plan section of the Supply Plan and supports the Companies' requests to construct transmission system network upgrades and the continued need for the Greenlink projects.

Layne Maxfield, Manager, Transmission System Planning, supports the Transmission Plan and the Companies' requests to construct transmission system network upgrades for large customer additions.

Shahzad Lateef, Senior Project Director, supports the updated cost forecast for the Greenlink transmission projects.

John Tsoukalis, Principal at The Brattle Group, supports the economic benefits of the Greenlink transmission projects and addresses the projects' updated cost forecast.

Kiley Moore, Director, Transmission Policy and Business Services, supports the federal regulatory requirements related to the Greenlink transmission projects.

Josh Langdon, Vice President of Transmission, sponsors an updated cost forecast for the Greenlink transmission projects and introduces other witnesses addressing the projects.

Eric Schwarzrock, Vice President, Customer Solutions and Projects, supports the Companies' process working with customers to connect large loads to the transmission and distribution system.

F. Economic Analysis. The Economic Analysis narrative follows the Supply Plan narrative and discusses the methodologies and analytical tools used to perform the integrated economic analysis that underlies the Companies' selection of the Preferred Plan and Alternate Plan. This section also describes the calculation of environmental externalities for the Preferred and Alternate Plans. The economic analysis narrative is supported by the following technical appendices:

- ECON-1 - Notice and Presentation from Stakeholder Briefings
- ECON-2 - Description of Modeling Software
- ECON-3 - Average Generation Costs for Preferred Plan - Redacted
- ECON-4 – Summary of Production Cost Output for All Cases - Redacted
- ECON-5 - Loads and Resources Tables
- ECON-6 - Capital Projects (all cases and sensitivities) - Confidential
- ECON-7 - PWRR (Production Costs plus Capital Costs)
- ECON-8 – Area Diagram
- ECON-9 – NERA Report
- ECON-10 – Candidate Resources - Redacted
- ECON-11 – Average Marginal Energy Costs for Preferred Plan
- ECON-12 – 2024 Resource Adequacy Study
- ECON-13 – Uncertainty Reserves
- ECON-14 - Sierra Subsystem Resource Adequacy Analysis
- ECON-15 – DSM Cases – Redacted
- ECON-16 – No Greenlink Illustrative Case - Redacted

The Economic Analysis narrative, as well as the technical appendices supporting the narrative, are sponsored in the prepared direct testimony of **Kimberly Williams**, Director of Resource Planning and Analysis, **Nicolai Schlag**, Partner at Energy and Environmental Economics, as well as **Dr. David Harrison, Jr.**, Affiliated Consultant at NERA Economic Consulting. Mr. Schlag sponsors the 2024 resource adequacy study, analysis of uncertainty reserves, and Sierra subsystem resource adequacy analysis contained in Technical Appendices ECON-12, ECON-13, and ECON-14. Dr. Harrison sponsors the discussion and analysis of environmental externalities contained in the Economic Analysis discussion, as well as Technical Appendix ECON-12.

G. Financial Plan. The 2024 Joint IRP narrative closes with a discussion of the Financial Plan following the Economic Analysis narrative. This section of the narrative discusses the methodologies and analytical tools used to evaluate the impact of the Preferred and Alternate Plans on the Companies' financial metrics. **Mr. Michael Behrens**, Chief Financial Officer, sponsors the Financial Plan of the 2024 Joint IRP. **Christopher Sarda**, Financial Planning & Analysis Capital Services Director, sponsors the financial forecast modeling and analysis used to support the Financial Plan as well as the alternative plans rate impact analyses.

H. Energy Supply Plan. The 2024 Joint IRP includes an ESP. Because the IRP statute requires that an ESP be processed in 135 days, while the full IRP is to be processed in 210 days, the Companies have segregated the ESP narrative, testimony and technical appendices into stand-alone volumes filed as part of the 2024 Joint IRP. Together the 2024 ESP narrative, prepared direct testimony and technical appendices provide the Companies' recommended power procurement plans, fuel procurement plans, and risk management strategies based on current market conditions during the 2024 ESP period. The 2024 ESP narrative is supported by the following technical appendices and prepared direct testimony.

1. Policy including Prudence Determinations and Compliance with Prior Commission Directives. **Mr. Atkins**, introduced above, is the overall policy witness for the

2024 ESP and sponsors Sections 1 (Executive Summary), 2.C (Energy Requirements), 2.G (Financial Gas Requirement), 3.A (Market Fundamentals), 4 (Power Procurement Plan), 5.A (Physical Gas Procurement Plan), 5.C (Recommend Gas Hedging Plan), 8 (Determination of Prudence), 9 (Commission Directives) of the ESP narrative and Technical Appendix Items GAS-1.

2. ***Load Forecasting***. **Mr. Pollard**, introduced above, sponsors the 2024 ESP load forecast, which is described in Section 2.A of the ESP narrative. The Technical Appendix items LF-1 through LF-8 are identical as between the ESP and IRP, and thus are included only once, with the 2024 Joint IRP.

3. ***Fuel and Purchased Power Forecasting*****.** **Mr. Vukanovic**, introduced above, sponsors Sections 3.A (Market Fundamentals w/Mr. Atkins) and 3.B (Fuel and Purchase Power Forecasts) in the narrative 2024 ESP, as well as the following Technical Appendix FPP-1 – Fuel and Purchased Power Price Forecasts (Confidential).[4]

4. ***Power Procurement Plan*****.** **Mr. Atkins,** and **Mr. Spitzer**, both introduced above, as well as **Jenny Naughton,** Revenue Requirement and FERC Manager, and **David Maher,** Project Consultant for Metasys Inc., sponsor portions of the power procurement plan, as well as the following Technical Appendix:

- GAS-2 - Summary of Actual and Forecasted BTERs and DEAAs

5. ***Fuel Procurement Plan***. **Mr. Atkins** and **Mr. Vitello**, introduced above, sponsor the fuel procurement plan.

6. ***Economic Analysis*****.** **Mr. Maher**, introduced above, sponsors Economic Analysis discussion in the ESP and the following Technical Appendix item:

- ECON-1 – PROMOD Results (Confidential)

7. ***Risk Management Strategy*****.** **Adrian Cacuci**, Treasurer, sponsors Section 7 (Risk Management Strategy) and portions of Section 8 (Determination of

[4] The fuel and purchased power price forecast for the ESP period from 2025 through 2027 is identical to the IRP forecast contained in IRP Technical Appendix FPP-1.

Prudence) of the 2024 Joint ESP, and sponsors the following Technical Appendices:

- ESP-RM-1 Risk Management and Control Policy
- ESP-RM-2 Energy Risk Management and Control Policy
- ESP-RM-3 Credit Risk Management and Control Policy

V.
CONFIDENTIALITY

Certain information set forth in the narratives and Technical Appendices is commercially confidential and/or trade secret information subject to protection pursuant to NRS § 703.190. Specifically, the confidential information in this filing, along with the basis for the assertion of confidentiality, is set forth below.

Load Forecast. Technical Appendix LF-6 contains third-party proprietary information and is being provided confidentially.

Fuel and Purchased Power Price Forecasts and Market Fundamentals. The Companies prepared price forecasts for fuel and purchased power for the 2024 Joint IRP and the 2024 ESP. The following figures in the fuel and purchased power narrative in the 2024 Joint IRP are confidential and have been redacted in the public version of the filing.

- Figure PF-2 – Annual Average Gas Price Forecast
- Figure PF-3 – Average Market Implied Heat Rate
- Figure PF-4 – Average Annual Power Price Forecast - Mead
- Figure PF-5 – Base, High and Low Gas Price Forecast - Rockies
- Figure PF-6 – Base, High and Low Gas Price Forecast – Alberta (AECO)
- Figure PF-7 – Base, High and Low Power Price Forecast - Mead
- Figure PF-8 – Projected Capacity Prices

In addition, in the 2024 Joint IRP, Technical Appendix item FPP-1 provides additional confidential fuel price information.

In the 2024 ESP, the following figures in the fuel and purchased power narrative are confidential and have been redacted in the public version of the filing:

- Figure ESP-29 – Natural Gas Price Forecasts
- Figure ESP-30 – Natural Gas Price Forecast (Rockies)
- Figure ESP-31 – Natural Gas Price Forecast (Alberta)
- Figure ESP-32 – Power Price Forecast (Mead-on-Peak)

In addition, the 2024 ESP market fundamentals narrative reproduces the above figures, and the gas procurement plan lists confidential pricing values. Technical Appendix FPP-1 contains confidential fuel price information.

Fuel and purchased price forecasts qualify for confidential treatment under NRS § 703.190. They derive independent economic value from not being generally known and disclose the Companies' views and expectations of the relevant markets. This information is not known outside the Companies and its distribution is limited within the Companies. Releasing this highly sensitive information would disadvantage the Companies by limiting their ability to foster competition among prospective suppliers, compromising the Companies' negotiating position and reducing its bargaining leverage. Publication of this information would unfairly advantage competing coal buyers and impair the Companies' ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of its customers.

Gas Premiums. In the 2024 Joint IRP, Fuel Supply narrative contains confidential gas price premiums. This confidential information is commercially sensitive and/or trade secret information that derives independent economic value from not being generally known. Disclosure of this confidential information to any third party would adversely affect the Companies' ability to obtain favorable terms from its gas suppliers.

Operational Data. A comprehensive IRP analysis necessarily relies on confidential information regarding the performance characteristics of the Companies' generating fleet. In the 2024 Joint IRP, the following Technical Appendix items are provided in redacted form in the public version of the filing.

- GEN-1 – Unit Characteristics Table
- GEN-3 – Generation Brownfield Study
- ECON-3 – Average Generation Costs
- ECON-4 – Production Cost Summaries
- ECON-6 – Capital Projects
- ECON-10 – Candidate Resources
- ECON-15 – DSM Cases
- ECON-16 – No Greenlink Case

Similar information is included in Technical Appendix ECON-1 in the 2024 ESP.

Generation unit characteristics and similar operational data qualify for confidential treatment under NRS § 703.190. The information in these Technical Appendices derive independent economic value from not being generally known. This information discloses the Companies' views and expectations of the relevant markets and its future procurement opportunities. This information is not known outside the Companies and its distribution is limited within the Companies. Releasing this highly sensitive information would disadvantage the Companies by limiting their ability to foster competition among prospective energy suppliers and buyers; compromising the Companies negotiating positions and reducing their bargaining leverage. Publication of this information would unfairly advantage competing market participants and impair the Companies' ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of its customers.

In addition, parts of the Supply Plan narrative contain confidential information. Tables GEN-3, GEN-4, GEN-6, and GEN-7 within the Generation Section of the Supply Plan contain confidential projects cost information that is currently in development, subject to on-going bids, or is being negotiated.

Renewables. The following Technical Appendices for the Renewables Section of the Supply Plan in the 2024 Joint IRP, or portions thereof, are confidential:

- REN-3-DLE(a) Dry Lake East PPA (Redacted)
- REN-3-DLE(b) Dry Lake East Due Diligence Summary
- REN-4-BS3(a) Boulder Solar III PPA (Redacted)
- REN-4-BS3(b) Boulder Solar III Due Diligence Summary
- REN-5-LS(a) Libra PPA (Redacted)
- REN-5-LS(b) Libra Due Diligence Summary
- REN-6-CS2(a) Corsac Generating Station 2 PPA (Redacted)
- REN-6-CS2(b) Corsac Generating Station 2 Due Diligence Summary
- REN-8 Bid Scores Summary 2023 OR RFP

Technical Appendices REN-3-DLE(a) Dry Lake East PPA, REN-4-BS3(a) Boulder Solar III PPA, REN-5-LS(a) Libra PPA, and REN-6-CS2(a) Corsac Generating Station 2 PPA contain a redacted Exhibit that lists approved vendors. This information is commercially sensitive and its disclosure can result in harm to the Companies, the Companies' contractual counterparties, and the vendors either included or excluded from the list.

The Technical Appendices containing the due diligence summaries are confidential because, if publicly disclosed, could provide an unfair market advantage to competitors and future bidders by showing the Companies' internal analysis on projects. Technical Appendix REN-8 contains 2023 RFP bid information from non-winning bids submitted to the Companies under confidentiality agreements. Table REN-8 within the Supply Plan also reflects confidential bid information from candidate resources.

Demand Side Plan. Technical Appendix DSM-21, M&V Report Energy Smart Schools, contains personal information of individuals which has been redacted.

Forecasted Financial Data. A comprehensive IRP analysis necessarily relies on confidential information regarding the impact of the Preferred and Alternate Plans on the Companies' financial performance. That information is discussed in the narrative of the

Financial Plan. The following figures in the Financial Plan narrative, as well as the Financial Plan in-text references to the information contained in those figures, are confidential and have been redacted in the public version of the filing.

- Figure FP-3 – Nevada Power Summary of External Debt Financing
- Figure FP-4 – Sierra Summary of External Debt Financing
- Figure FP-11 – Nevada Power Funds from Operations to Total Debt
- Figure FP-12 – Nevada Power EBITDA Interest Coverage
- Figure FP-13 – Nevada Power Total Debt to Total Capital
- Figure FP-14 – Nevada Power Cash from Operations to CAPEX
- Figure FP-15 – Sierra Funds from Operations to Total Debt
- Figure FP-16 – Sierra EBITDA Interest Coverage
- Figure FP-17 – Sierra Total Debt to Total Capital
- Figure FP-18 – Sierra Cash from Operations to CAPEX

Additionally, Prepared Direct Testimony of Mike Behrens contains Figures Behrens-Direct-3 and Behrens-Direct-4, which depict Nevada Power and Sierra credit metrics. The financial analysis accompanying the 2024 Joint IRP qualifies for confidential treatment under NRS § 703.190. It derives independent economic value from not being generally known and discloses the Companies' views and expectations of the relevant markets. This information is not known outside the Companies and its distribution is limited within the Companies. Moreover, the financial analysis contains non-public financial data. Exhibit Behrens-Direct-2 is confidential because it consists of third-party, Moody's, copyrighted material. Reproduction and dissemination of the material is explicitly prohibited.

Pursuant to NAC § 703.5274(1), one unredacted copy of the confidential information will be filed with the Commission's Secretary in a separate envelope stamped "confidential." Redacted versions of confidential information will be submitted for processing and posting onto the Commission's public website.

Pursuant to NAC § 703.5274(2), the Companies hereby request that the above-described information not be disclosed to the public. The Companies request that this information remain confidential for a period of five years.

Confidential treatment of the above-described information will not impair the ability the Staff or the BCP to fully investigate the Companies' proposals. Pursuant to NAC § 703.527 and § 703.5274, Staff and BCP have already executed a protective agreement for this case and will be immediately provided unredacted copies of the filing.

VI.
REQUEST FOR DEVIATION FROM REGULATION

NAC § 704.0097 provides that the Commission may allow deviation from any provision of NAC Chapter 704 if:

(1) Good cause for the deviation appears;

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

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

NAC § 704.9237(2)(f) states that the DRP must:

> Be developed by a utility using a forecast of net distribution system load and distributed resources. The forecast must be for a period of not less than 6 years, beginning with the year after the distributed resources plan is filed. The net distribution system load and distributed resources forecast will include system, substation and feeder level net load projections and energy and demand characteristics for all distributed resource types.

The Companies utilized net distribution feeder, substation transformer, and transmission forecasts to determine the constraints on the transmission and distribution systems. System-level forecasts for certain distributed resource types are filed with the Commission in the Load Forecast and Technical Appendix LF-1 of this 2024 Joint IRP filing and the DRP does not alter those forecasts in any way. However, all distributed resource types as defined in NAC § 704.90583 are not yet represented in those forecasts. Also of note is that the Companies have disaggregated system-level private solar photovoltaic ("PV") forecasts down to the substation and feeder levels, as noted in the DRP. As a result, NV Energy requests a waiver of NAC § 704.9237(2)(f) as it continues to investigate alternative methods for developing substation and feeder level DER forecasts. The Companies' request to deviate is in the public interest because it does not impact the analysis or conclusion of the DRP and recognizes the DRP is an evolving process that requires some flexibility.

In addition, NAC § 704.9237(3)(b) states that the DRP must include a hosting capacity analysis of the distribution system evaluated "under normal conditions and planned and unplanned contingency conditions." The Companies completed the hosting capacity analysis ("HCA") for the DRP under normal system operating conditions, but not under planned or unplanned contingency conditions. The Companies discussed the issue of performing HCA under contingency conditions internally and initially concluded that any contingencies analyzed would need to be limited in scope to ensure that the number of cases analyzed do not create an untenable situation in terms of being able to complete the analysis. NV Energy will continue to investigate how other utilities may be approaching this issue to ascertain if there are any techniques that can be applied to ensure that the analytical process would not be made impractical by the addition of contingency conditions. The Companies request a waiver from NAC § 704.9237(3)(b). The Companies' request to deviate is in the public interest because it does not impact the analysis or conclusion of the DRP and recognizes the DRP is an evolving process that requires flexibility.

VII.
REQUEST TO CONSOLIDATE

Pursuant to NAC § 703.740 and the Commission's order in Docket No. 19-07005, the Companies requests that this Application be consolidated with the Application of Sierra Pacific Power Company d/b/a NV Energy for Approval of its 2024 Natural Gas Conservation and Energy Efficiency Plan Report.

VIII.
PRAYER

WHEREFORE, the Companies requests that the Commission:

(1) Accept the Action Plan as it is set forth in Exhibit A to this Application which includes the following items:

a) Regarding the 2024 Joint IRP, approval of the long-term base load forecast presented in the Load Forecast and Market Fundamentals volume of this filing as being the most accurate information upon which to base long-term planning decisions through the Action Plan period;

b) Regarding the 2024 ESP, approval of the three-year base load forecast presented in the 2024 ESP as being the most accurate information upon which to base near-term planning decisions through the Action Plan period;

c) Regarding the 2024 Joint IRP, approval of the base long-term fuel and purchased power price forecasts presented in FPP-1 as presenting the best and most accurate information upon which to base long-term planning decisions through the Action Plan period;

d) Regarding the 2024 ESP, approval of the base three-year fuel and purchased power price forecasts presented in the 2024 ESP as presenting the best and most accurate information upon which to base near-term planning decisions through the Action Plan period;

e) Regarding the 2024 Joint IRP, approval of the Companies' recommended annual limits on the total amount of energy and capacity that eligible NRS Chapter 704B customers may be authorized to purchase from providers of new electric resources during the Action Plan period, and the Net Differential Energy Rate of $0.04165 per kWh, and the Variable O&M Credit (Charge) of $-0.00015 per kWh for the Action Plan period;

f) Regarding the 2024 Joint IRP, issuance of a list of any current or ongoing legislatively mandated public policy programs for which eligible customers are required to pay costs, fees, charges or rates pursuant to subsection 8 of NRS 704B.310;

g) Approval of the Companies' Preferred Plan, which includes:

i. A Supply Plan addition of two 200 MW (nominal) gas-fired simple-cycle turbines at the North Valmy generation station. Commercial operation is expected by June 30, 2028. The estimated cost of the project is approximately $573.3 million (2024 dollars), without AFUDC, and will serve Sierra's customers.

ii. A Supply Plan addition of the Dry Lake East PV and BESS PPA for 200 MW of renewable energy and 200 MW of storage. Commercial operation is expected in December of 2026. The PPA is with Nevada Power for a 25-year term at a flat energy price of $36.78 per MWh and 20-year term for the battery component at a rate of $13,440 per MW-month.

iii. A Supply Plan addition of the Boulder Solar III PV and BESS PPA for 127.9 MW of renewable energy and 127.9 MW of storage. Commercial operation is expected in June of 2027. The PPA is with Nevada Power for a 25-year term at a flat energy price of $34.60 per MWh and 20-year term for the battery component at a rate of $15,460 per MW-month; however, for years 21-25, the remaining battery capacity will be available exclusively to Nevada Power at a price of $0.00 per MW-month.

iv. A Supply Plan addition of the Libar Solar PV and BESS PPA for 700 MW of renewable energy and 700 MW of storage. Commercial operation is expected in December of 2027. The PPA is with Nevada Power for a 25-year term at a flat energy price of $34.97 per MWh and 20-year term for the battery component at a rate of $13,350 per MW-month; however, for years 21-25, the remaining battery capacity will be available exclusively to Nevada Power at a price of $0.00 per MW-month.

v. A Supply Plan addition of Tolson substation transformer #2, 230/138 kV, at a cost of $9.60 million (2024 dollars), with a March 2028 estimated in-service date.

vi. A Supply Plan addition of Reid Gardner-Harry Allen 230 kV line #3 and separate of lines #1 and #2, at a cost of $24.20 million (2024 dollars), with a May 2026 estimated in-service date.

vii. A Supply Plan addition of Lantern-Comstock Meadows 345 kV line, at a cost of $105 million (2024 dollars), with a December 2029 estimated in-service date.

viii. A Supply Plan addition of Comstock Meadows 345/120 kV transformer #2, at a cost of $13 million (2024 dollars), with a May 2027 estimated in-service date.

ix. A Supply Plan addition of West Tracy transformer #1 345/120 kV, at a cost of $13 million (2024 dollars), with a May 2028 estimated in-service date.

x. A Supply Plan addition of Lantern-Comstock Meadows 345 kV line, at a cost of $105 million (2024 dollars), with a December 2029 estimated in-service date.

xi. A Supply Plan addition of 230 kV line breakers at the Machacek Substation, at a cost of $14.8 million (2024 dollars), with a June 2027 estimated in-service date.

xii. A Supply Plan addition of Darling Substation with two 230/12 kV transformers, at a cost of $43.5 million (2024 dollars), with a June 2028 estimated in-service date.

xiii. A Supply Plan addition of Log Cabin Substation with a 230/12 kV transformer, at a cost of $33.75 million (2024 dollars), with a June 2028 estimated in-service date.

xiv. A Supply Plan addition of Spring Canyon Substation with three 230/12 kV transformers, at a cost of $49.6 million (2024 dollars), with a December 2026 estimated in-service date.

xv. A Supply Plan addition of Ft. Churchill-Comstock Meadows 345 kV line #2 at an incremental cost of $97.4 million (2024 dollars), with a December 2027 in-service date.[5]

xvi. A Supply Plan addition of the third and fourth 525/345 kV transformers located at the Ft. Churchill Substation, at a cost of $12 million (2024 dollars) for each transformer. Conditional approvals are sought for these transformers as they will be constructed only upon loads connecting at the Ft. Churchill Substation materializing.

xvii. A Supply Plan addition of Mackay Substation 345 kV, at a cost of $28 million (2024 dollars), with a December 2027 estimated in-service date.

xviii. A Supply Plan addition of Gosling Switching Station 345 kV, at a cost of $5 million (2024 dollars), with an April 2027 estimated in-service date.

[5] The Commission previously approved permitting, preliminary design, and engineering for this line at a cost of $12.8 million. The total project cost is $110.2 million. The total project cost of $110.2 million is also included in the updated Greenlink estimate.

xix. Siting and permitting costs for Ft. Churchill-Veterans 525 kV line in the amount of $14 million (2024 dollars), with May 2031 estimated in-service date.

xx. A Supply Plan addition of Naniwa Switching Station 345 kV, at a cost of $26 million (2024 dollars), with May 2027 estimated in-service date.

xxi. A Supply Plan addition of Nighthawk 345/120 kV Substation, at a cost of $67 million (2024 dollars), with a December 2028 estimated in-service date.

xxii. A Supply Plan addition of Vaquero 345/120 kV Substation, at a cost of $30 million (2024 dollars), with a May 2029 estimated in-service date.

xxiii. A Supply Plan addition of Viking 345 kV Switching Station, at a cost of $55 million (2024 dollars), with a May 2029 estimated in-service date.

xxiv. A Supply Plan addition of Veterans 345/120 kV Substation, at a cost of $40 million (2024 dollars), with a May 2030 estimated in-service date.

xxv. A Supply Plan addition of Prospector 230 kV line terminal, at a cost of $2.2 million (2024 dollars), with a December 2026 estimated in-service date.

xxvi. $5.22 million for the necessary network upgrades to add a 345 kV lead line terminal at the North Valmy Substation bus for the generator interconnection of the Valmy Simple-Cycle Plant.

xxvii. $4 million for the necessary network upgrades to construct a new line position and lead line at the Harry Allen Substation for the generator interconnection of the Dry Lake East PV/BESS project.

xxviii. $3.9 million for the necessary network upgrades to construct a new line position at the Ft. Churchill Substation for the generator interconnection of the Libra PV/BESS project.

xxix. continued approval of the Greenlink project with a combined budget for Greenlink West, Greenlink North and Common Ties of $4,128 million.[6]

h) Regarding the 2024 Joint IRP, approval of the Corsac Generating Station 2 PPA for 115 MW of geothermal energy. Commercial operation is expected in January of 2030. The PPA is with Sierra for a 15-year term at a flat energy price of $107.00 per MWh. The PPA will provide 24/7 renewable energy and PCs to Callisto Energy via an ESA. The PPA is not effective until the ESA has been fully executed and all conditions to its effectiveness have been satisfied;

i) Regarding the 2024 Joint IRP, $2 million for the necessary network upgrades to add a 345 kV line terminal at Lantern bus for the generator interconnection of the Corsac Geothermal project;

j) Regarding the 2024 Joint IRP, approval of the request to designate Greenlink West and common ties as critical facilities;

k) Regarding the 2024 Joint IRP, approval of the construction work in progress accounting treatment for the Greenlink project;

l) Regarding the 2024 Joint IRP, approval of a regulatory asset, with no carrying charges, to record and include the Greenlink depreciation expense;

m) Regarding the 2024 Joint IRP, approval of the Companies' proposed long-term avoided costs;

[6] The $110 million estimated cost of the Ft. Churchill-Comstock Meadows #2 345 kV line is subtracted from this estimate to avoid double counting. The total estimated cost of the Greenlink project is $4,239 million.

n) Regarding the 2024 Joint IRP, approval of the proposed Grid Value Portfolio as the DSM Plan with the following budgets:

   i. Nevada Power with budgets of $55.9 million, $60.7 million, and $65.3 million in 2025, 2026, and 2027, respectively; Sierra $20.2 million, $22 million, and $23.9 million in 2025, 2026, and 2027 respectively; and NV Energy combined $76.1 million, $82.7 million, and $89.2 million in 2025, 2026, and 2027, respectively;

o) Regarding the 2024 Joint IRP, Commission review and acceptance of an energy savings goal that proposes a combination of energy savings, in kilowatt-hours, and incremental demand reduction capacity, in kilowatts, during the Action Plan period. The proposed Grid Value portfolio implements a demand savings target reduction of 175 MW with a kWh savings target of 0.7 percent of the forecasted weather normalized retail sales statewide for the three-year period;

p) Regarding the 2024 Joint IRP, a finding that the Companies have complied with all relevant statutory, regulatory, and Commission directive requirements that are listed in Table DSM-10 of the DSM Plan;

q) Regarding the 2024 Joint IRP, Commission review and acceptance of the measurement and verification reports for program year 2023 provided in Technical Appendices DSM-13 through DSM-23;

r) Regarding the 2024 Joint IRP, approval of the DRP, which includes:

   i. A finding that the DRP meets the requirements in NRS § 704.741(4) and NAC §704.9237;

   ii. A request for $0.3 million to investigate and develop a Non-Wires Alternative Tariffed-On-Bill Pilot; and

   iii. A request for a concept approval of the size and type of the Utility Owned Community Solar ("UOCS") and Solar for All ("S4A") within this IRP.

s) Regarding the 2024 Joint IRP, approval of the Transportation Electrification Plan ("TEP"), as part of the DRP , which includes:

i. A finding that the TEP meets the requirements in NRS §§ 704.741(4)(f) and 704.7867;

ii. Approval of the TEP with the following budgets: \$5.2 million, \$6.1 million, \$8 million for NV Energy in 2025, 2026, and 2027, respectively;

iii. The TEP Technical Appendix submitted, which includes Technical Appendices TEP-1 through TEP-6, is in compliance with NAC 704.9237(3)(f);

iv. Approval of the Companies' proposed revisions to Schedule No. ESB-V2G, Electric School Bus Vehicle-to-Grid Trial, tariffs provided in Application Exhibit E.

t) Regarding the 2024 Joint IRP, approval to establish a regulatory asset to record costs of the 2025-2027 Transportation Electrification Plan with carrying charges;

u) Regarding the 2024 ESP, acceptance and approval of the power procurement plan and an affirmative finding, consistent with NAC § 704.9494(3), that the power procurement strategy is prudent;

v) Regarding the 2024 ESP, acceptance and approval of the physical gas procurement plan and an affirmative finding, consistent with NAC § 704.9494(3), that the physical gas procurement strategy is prudent;

w) Regarding the 2024 ESP, acceptance and approval of its gas transportation plan, and an affirmative finding, consistent with NAC § 704.9494(3), that the gas transportation strategy is prudent;

x) Regarding the 2024 ESP, acceptance and approval of its gas hedging plan, and an affirmative finding, consistent with NAC § 704.9494(3), that the gas hedging plan is prudent;

y) Regarding the 2024 ESP, acceptance and approval of the coal procurement plan, and an affirmative finding consistent with NAC § 704.9494(3) that its coal procurement strategy is prudent;

z) Regarding the 2024 ESP, acceptance an approval of the risk management strategy, and an affirmative finding consistent with NAC § 704.9494(3) that its risk management strategy is prudent;

aa) Regarding the 2024 ESP, an affirmative finding that Nevada Power has satisfied the Commission directive from the Commission's Order approving the modified stipulation in Docket No. 13-08024, requiring the Company to continue conducting quarterly gas hedging workshops with Staff and BCP to review the implementation of the elements of the ESP and the approved hedging strategy;

bb) Regarding the 2024 ESP, pursuant to NAC § 704.9494, the Companies request that the Commission determine that the elements of the ESP are prudent by making the following findings:

i. That the ESP balances the objectives of minimizing the cost of supply, minimizing retail price volatility and maximizing the reliability of supply over the term of the plan; and

ii. That the ESP optimizes the value of the overall supply portfolio of the utility for the benefit of its bundled retail customers; and

iii. That the ESP does not contain any feature or mechanism that would impair the restoration of the creditworthiness of the utility or would lead to a deterioration of the creditworthiness of the utility;

(2) Approval of the Companies' request to deviate from NAC 704.9237(2)(f) and NAC 704.9237(3)(b);

(3) Find that the Companies have satisfied the directives and compliance items from Docket Nos. 21-06001, 22-03024, 22-07003, 22-07004, 22-09006, 23-02001, 23-02010, 23-02011, 23-06044, and 23-08015;

(4) Grant the Companies' request to maintain the confidentiality of the information as provided above;

(5) Consolidate this Application with the Application of Sierra Pacific Power Company d/b/a NV Energy for Approval of its 2024 Natural Gas Conservation and Energy Efficiency Plan Report;

(6) Grant any other requests as are specifically set forth in the testimony and exhibits filed herewith, both those that are directly addressed and those that are not directly addressed in this Application; and

(7) Grant such additional other relief as the Commission may deem appropriate and necessary.

Dated this 31st day of May, 2024.

Respectfully submitted,

NEVADA POWER COMPANY
SIERRA PACIFIC POWER COMPANY

/s/ Roman Borisov
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EXHIBIT A

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

2024 Joint Integrated Resource Plan
Docket No. 24-05_____

Action Plan Period January 1, 2025, to December 31, 2027

SECTION I
INTRODUCTION — NAC § 704.9489(1)(a)

Nevada Power Company ("Nevada Power") and Sierra Pacific Power Company ("Sierra" and, together with Nevada Power, the "Companies" or "NV Energy") are filing this joint integrated resource plan ("2024 Joint IRP"). The 2024 Joint IRP focuses on affordability, reliability, and sustainability. The 2024 Joint IRP continues the Companies' commitment to meeting the state's clean energy policies and goals, while also meeting the energy needs and demands of their customers. In determining their Preferred Plan and preparing the Action Plan, the Companies developed four long-term primary expansion plans for meeting customers' demands and tested them to determine how each performed across the range of potential load, power purchase price, fuel price and carbon emissions cost scenarios. The Companies have selected as their Preferred Plan the Balanced Plan, the centerpiece of which is:

1) Libra – a 700 megawatt ("MW") photovoltaic ("PV") system paired with 700 MW of battery storage. The project has an in-service date of December 2027.

2) Dry Lake East – a 200 MW PV system paired with 200 MW of battery storage. The project has an in-service date of December 2026.

3) Boulder Solar III – a 128 MW PV system paired with 128 MW of battery storage. The project has an in-service date of June 2027.

4) Valmy Simple-Cycle Project – a 411 MW of hydrogen-capable natural gas combustion turbines at the North Valmy Generating Station with an in-service date of June 2028.

5) Transmission projects required to meet customers' needs as presented in the Transmission Plan.

The Companies present for Commission review and continued approval an increased budget for the Greenlink project with this Joint Application. The Commission approved the Greenlink project in Docket Nos. 20-07023 and 21-06003. The Greenlink project is embedded in all four alternative plans. In recent years, the cost of transmission infrastructure construction has seen a notable increase based on inflation, supply chain constraints, and labor rate escalations. The Greenlink project has not been immune to that increase. In addition, finalization of the project routing and design, Bureau of Land Management stipulations on environmental risk mitigation, and further budget development, based on detailed engineering, have contributed to the increased project costs. The Companies' analysis demonstrates that the Greenlink project continues to be the best option to serve the electric needs of the state, ensure NV Energy system reliability and resiliency, increase renewable energy production and promote economic development.

The Demand Side Management ("DSM") programs proposed with this IRP provide grid value with a new savings target and utilization of evolving planning processes that seek to create foundational strategies to enable flexible load. Specifically, the proposed DSM Grid Value portfolio implements a demand savings target reduction of 175 incremental new dispatchable MW with an energy savings target (expressed in kilowatt-hours ("kWh")) of 0.7 percent of the forecasted weather normalized retail sales over the Action Plan period. The DSM Grid Value portfolio also allocates 10 percent of its total Action Plan budget on programs directed to low-income customers or those residing in historically underserved communities ("HUCs"). NV Energy proposes to continue to spend seven percent of that 10 percent allocation towards its standalone Low Income program, proposed in the DSM Plan as the Qualified Customer Program.

The 2024 Joint IRP also presents a Distributed Resources Plan ("DRP") that contains a Transportation Electrification Plan ("TEP"). The DRP meets the statutory and regulatory objectives and continues to evolve as the Companies, the Commission and stakeholders become more familiar with the technologies.

A complete list of all Action Plan items follows in Section II.

SECTION II
ACTION PLAN ITEMS — NAC § 704.9489(1)(b)

LOAD FORECAST – IRP & ESP

- Approval of the long-term base load forecast presented in the Load Forecast and Market Fundamentals volume of this filing as being the most accurate information upon which to base long-term planning decisions through the Action Plan period.
- Approval of the Companies' recommended annual limits on the total amount of energy and capacity that eligible NRS Chapter 704B customers may be authorized to purchase from providers of new electric resources during the Action Plan period, and the proposed Net

Differential Energy Rate and the Variable O&M Credit (Charge) for the Action Plan period.

- Approval of the three-year base load forecast presented in the 2024 Energy Supply Plan ("2024 ESP") as being the most accurate information upon which to base near-term planning decisions through the Action Plan period.

FUEL AND PURCHASED POWER PRICE FORECASTS – IRP & ESP

- Approval of the base long-term fuel and purchased power forecasts presented in Technical Appendix FPP-1 as presenting the best and most accurate information upon which to base long-term planning decisions through the Action Plan period.
- Approval of the base three-year fuel and purchased power forecast presented in the 2024 ESP as presenting the best and most accurate information upon which to base near-term planning decisions through the Action Plan period.

GENERATION – IRP

- Approval of the construction by the Companies of the Valmy Simple-Cycle Plant, which consists of two new hydrogen-capable natural gas combustion turbines located at the North Valmy Generating Station with an in-service date of June 2028.

RENEWABLES – IRP

- Approval of the Dry Lake East Power Purchase Agreement ("PPA") which is a 200 MW PV and 200 MW Battery Energy Storage System ("BESS") project located in Clark County, Nevada, with an in-service date of December 1, 2026.
- Approval of the Boulder Solar III PPA which is a 128 MW PV and 128 MW BESS project located in Clark County, Nevada, with an in-service date of June 1, 2027.
- Approval of the Libra PPA which is a 700 MW PV and 700 MW BESS project located near the Mineral County/Lyon County border, Nevada, with an in-service date of December 1, 2027.

TRANSMISSION — IRP

- Approval for the construction of one transmission system network upgrade necessary to support the corrective action plan required per the North American Electric Reliability Corporation ("NERC") TPL-001 transmission planning standard.
- Approval for the construction of one transmission system network upgrade necessary to support the interconnection of generation per the Federal Energy Regulatory Commission ("FERC") jurisdictional Open Access Transmission Tariff ("OATT").
- Approval for the construction of nine transmission system network upgrades necessary to support the development of the Companies' new and existing Rule 9-driven customer load increases.

- Approval for the construction of one transmission system network upgrade necessary to improve area reliability for a Network Integration Transmission Service ("NITS") customer.
- Approval for the construction of seven transmission system network upgrades necessary to support the development of the Companies' new Rule 9 customer load increases that are currently under agreement negotiation.
- Approval for the construction of five transmission system network upgrades necessary to support the development of generation projects to support non-retail load increase.
- Continued approval of the Greenlink Nevada transmission project at the updated forecasted costs.

DEMAND SIDE PROGRAMS — IRP

- Approval of the budgets for the Grid Value portfolio for the 2025-2027 Action Plan period: Nevada Power with budgets of $55.9 million , $60.7 million, and $65.3 million in 2025, 2026, and 2027, respectively; Sierra with budgets of $20.2 million, $22 million, and $23.9 million in 2025, 2026, and 2027 respectively; and NV Energy with combined budgets of $76.1 million, $82.7 million, and $89.2 million in 2025, 2026, and 2027, respectively.
- Review and approval of the M&V reports for program year 2023 provided in Technical Appendices DSM-13 through DSM-23 for the DSM programs delivered in the 2023 program year.
- Review and acceptance of an energy savings goal that proposes a combination of energy savings, expressed in kWh, and incremental demand reduction capacity, in kilowatts, during the Action Plan period. The proposed Grid Value portfolio implements a demand savings target reduction of 175 incremental new dispatchable MW with a kWh savings target of 0.7 percent of the forecasted weather normalized retail sales statewide for the three-year period.

DISTRIBUTED RESOURCES PLAN — IRP

- Approval of the request for $300,000 to investigate and develop a Non-Wires Alternative Tariffed-On-Bill Pilot with stakeholders as detailed in the DRP's narrative Section 8.A.2.
- Approval of the TEP that covers transportation electrification programs and investments for the years 2025 to 2027, with a total budget of $19,233,000.
- The request for approval of the size and type of the Utility Owned Community Solar ("UOCS") and Solar for All ("S4A") placeholder resources within this DRP, such that the Companies can return for further approval with resource costs and customer program requirements and/or design, where relevant, in an appropriate filing.

2024 JOINT ENERGY SUPPLY PLAN — ESP

Power Procurement Plan. Based on the 2024 ESP Forecasts, Nevada Power has open power positions in the summers of 2025-2027. Note that any open positions in the spring or fall period of each year are "maintenance-driven," rather than "load-driven," and occur during lower system load conditions when wholesale power market supplies are generally available. The Companies propose to close the respective anticipated 2025-2027 summer open positions with firm products prior to respective summers.

The Companies propose to implement a four-season laddering strategy to close the remaining open power positions in 2025-2027 with the procurement of physical power and/or capacity acquired through a competitive bidding process. In addition, the Companies propose to negotiate and transact directly with counterparties as a supplement to the current request for proposal process. This would allow the Companies to seek custom non-standard firm energy products to help address short-term supply challenges during the early evening net demand peak period (i.e., the hours past the gross peak when solar production is very low or zero). Any proposed purchases of greater than three years in duration will be submitted to the Commission for approval in accordance with NAC §§ 704.9113 and 704.9512. Additional information regarding the closing of the open positions in the power procurement plan is provided in Section 4.C of the ESP narrative.

Additionally, the Companies monitor the portfolio seasonally, monthly, weekly, daily, and hourly and, when economic, seek to make short-term and forward sales of resources not expected to be needed to serve native load. This practice will be continued over the ESP period.

The Companies anticipate meeting their RPS credit obligations throughout the ESP planning period. This ESP incorporates the current regulations governing the Companies' ability to use PCs to meet the RPS and the calculation of the PCs. The plan also contemplates that Nevada Power will continue repaying its outstanding credit obligation to the joint pool for the benefit of Sierra.

Fuel Procurement Plan. The fuel procurement plan is made up of four components: (1) a physical gas procurement plan, (2) a gas transportation plan, (3) a gas hedging plan and (4) coal supply plan.

1) ***Physical Gas Procurement Plan.*** The Companies employ a four-season laddering strategy for physical gas purchases, through which 25 percent of projected monthly gas requirements per season are procured, subject to the availability of conforming bids and the willingness of suppliers to accept reasonable commercial terms. The Companies will continue to solicit physical gas supplies sourced from geographically diverse gas supply basins. Additional information regarding the Companies' physical gas procurement plan is provided in Section 5.A.

2) ***Gas Transportation Plan.*** Nevada Power is connected directly to the interstate pipeline systems with several major gas producing regions including the Permian, San Juan, and the Rocky Mountain supply basins, as well as California gas supply. The largest producing region with the best connectivity into and through Nevada Power's control area is the Rocky Mountain supply basin. The Kern River pipeline connects the Rocky Mountain basin through Nevada into southern California with a design capacity of 2,166,575 million British thermal units ("MMBtu") per day. This pipeline deliverability capacity is large in comparison to Nevada Power's daily needs.

   Sierra is well poised to access the dominant supply basins serving the Pacific Northwest with its existing firm gas transportation assets. These gas supply basins are the Rocky Mountain Basin, the San Juan Basin, British Columbia, and the Western Canadian Sedimentary Basin. Sierra receives gas supplies directly from two interstate natural gas pipelines: Paiute and Tuscarora. Paiute receives gas supplies upstream from Williams Gas Pipelines – Northwest, which sources its gas supplies from British Columbia, the San Juan Basin, and the Rocky Mountain region of Wyoming, Utah and Colorado. Tuscarora receives gas supplies from Gas Transmission Northwest, near Malin, Oregon, which is connected to the gas producing regions of the Western Canada Sedimentary basin.

   The Companies are seeking approval to maintain their current natural gas transportation portfolios. The contracts are listed in Figures ESP-38 and ESP-39. Additional information regarding the Companies' gas transportation plan is provided in Section 5.B of the ESP narrative.

3) ***Gas Hedging Plan.*** The Companies are proposing to continue the current approved hedging strategy and acquire no natural gas hedging products during the ESP period. The Companies will continue to monitor the natural gas market fundamentals and recommend changes to the hedging strategy in a future ESP update or ESP amendment as necessary.

4) ***Coal Supply Plan***. The coal requirements for Valmy are discussed in Section 2.H of the ESP narrative. It is anticipated that one Valmy unit will be taken offline in October 2025 for conversion to natural gas and coal burning will cease at Valmy in December of 2025 when the second unit will be taken offline for conversion to natural gas.

Risk Management Strategy. The Companies' risk management strategy includes:

- Detailed corporate governance and risk control policies and procedures,
- Compliance with approved supply plans,
- Reduced reliance on volatile wholesale markets,
- Use of competitive procurement processes,

- Gas hedging strategies, and
- Market monitoring.

For more detail on risk management strategy, see Section 7 of the ESP narrative.

Determination of Prudence. Pursuant to NAC §§ 704.9508(2) and 704.9494, the Commission can determine that the elements of an ESP are prudent if:

- The ESP balances the objectives of minimizing the cost of supply, minimizing retail price volatility, and maximizing the reliability of supply over the term of the plan.
- The ESP optimizes the value of the overall supply portfolio of the utility for the benefit of its bundled retail customers.
- The ESP does not contain any feature or mechanism that the Commission finds would impair the restoration of the creditworthiness of the utility or would lead to a deterioration of the creditworthiness of the utility.

This ESP satisfies the prudency requirements of NAC §§ 704.9508(2) and 704.9494 for each of the three elements, as discussed in detail in Section 8. The Companies acknowledge that the prudence of their implementation of an approved ESP will be determined in a future deferred energy proceeding. In addition, pursuant to NAC § 704.9504, the Companies may deviate from an approved ESP or ESP update "to the extent necessary to respond adequately to any significant change in circumstances not contemplated by the energy supply plan."

Continue to Conduct Gas Hedging Workshops. The Companies continue to conduct workshops bi-annually with the Staff and BCP and provide updates in the form of presentations for the remaining two quarters. Several topics are addressed, including energy market fundamentals, a monitoring matrix for potential gas hedging strategies, forward sales activity, gas procurement, and the most recent management decision on hedging.

SECTION III
FORECASTING DATA — NAC § 704.9489(1)(c)

The Companies will continue to pursue improvements to its forecast models including economic and price projections for all customer classes, end-use saturations and efficiency trends.

SECTION IV
TIMETABLE AND BUDGET FOR PROGRAMS — NAC § 704.9489(1)(d), (3), (4)

Figure S-29 shows the Action Plan timetable and budget by Action Plan year. Further details regarding the project schedules and milestones for capital projects are set forth in the Supply Plan. Additional information regarding the Demand Side Management Plan budget can be found in the Demand Side volume. Further details regarding the Distributed Resources Plan budget can be found in the Distributed Resources Plan volume.

FIGURE S-29
ACTION PLAN BUDGET

Action Plan Items	(2025$ Millions excluding AFUDC) 2025	2026	2027	3-Year Total
Nevada Power				
Energy Efficiency and Conservation				
Education Services	$ 1.9	$ 1.9	$ 1.9	$ 5.7
Residential Services	$ 34.1	$ 37.4	$ 40.0	$ 111.6
Non-Residential Services	$ 19.8	$ 21.4	$ 23.3	$ 64.6
Total Energy Efficiency and Conservation	$ 55.9	$ 60.7	$ 65.3	$ 181.9
Distributed Resources Plan				
Transportation Electrification Plan	$ 3.7	$ 4.3	$ 5.7	$ 13.6
Non Wires Alternative Tariffed On Bill Pilot Investigation	$ 0.2	$ -	$ -	$ 0.2
Total Distributed Resources	$ 3.8	$ 4.3	$ 5.7	$ 13.8
Plan for Supply				
Greenlink Nevada Transmission	$ 845.7	$ 505.2	$ 724.2	$ 2,075.1
Dry Lake East Transmission	$ 1.2	$ 2.9	$ -	$ 4.1
Transmission Infrastructure	$ 46.1	$ 51.5	$ 49.2	$ 146.8
Total Plan for Supply	$ 893.1	$ 559.5	$ 773.4	$ 2,226.0
Totals	$ 952.7	$ 624.5	$ 844.4	$ 2,421.6
Sierra				
Energy Efficiency and Conservation				
Education Services	$ 0.8	$ 0.8	$ 0.8	$ 2.4
Residential Services	$ 10.4	$ 11.4	$ 12.7	$ 34.5
Non-Residential Services	$ 9.0	$ 9.8	$ 10.4	$ 29.2
Total Energy Efficiency and Conservation	$ 20.2	$ 22.0	$ 23.9	$ 66.1
Distributed Resources Plan				
Transportation Electrification Plan	$ 1.5	$ 1.8	$ 2.3	$ 5.6
Non Wires Alternative Tariffed On Bill Pilot Investigation	$ 0.2	$ -	$ -	$ 0.2
Total Distributed Resources	$ 1.7	$ 1.8	$ 2.3	$ 5.7
Plan for Supply				
Greenlink Nevada Transmission	$ 762.9	$ 467.2	$ 390.5	$ 1,620.6
Valmy Combustion Turbines	$ 98.7	$ 28.4	$ 273.2	$ 400.3
Valmy CTs Transmission	$ -	$ 0.5	$ 1.1	$ 1.6
Libra Transmission	$ 0.4	$ 0.8	$ 2.8	$ 4.0
Transmission Infrastructure	$ 64.7	$ 98.7	$ 152.6	$ 316.0
Total Plan for Supply	$ 926.7	$ 595.6	$ 820.2	$ 2,342.5
Totals	$ 948.6	$ 619.3	$ 846.4	$ 2,414.3
NV Energy				
Energy Efficiency and Conservation				
Education Services	$ 2.7	$ 2.7	$ 2.7	$ 8.2
Residential Services	$ 44.5	$ 48.9	$ 52.7	$ 146.0
Non-Residential Services	$ 28.9	$ 31.2	$ 33.8	$ 93.8
Total Energy Efficiency and Conservation	$ 76.1	$ 82.7	$ 89.2	$ 248.0
Distributed Resources Plan				
Transportation Electrification Plan	$ 5.2	$ 6.1	$ 8.0	$ 19.2
Non Wires Alternative Tariffed On Bill Pilot Investigation	$ 0.3	$ -	$ -	$ 0.3
Total Distributed Resources	$ 5.5	$ 6.1	$ 8.0	$ 19.5
Plan for Supply				
Greenlink Nevada Transmission	$ 1,608.6	$ 972.4	$ 1,114.7	$ 3,695.6
Valmy Combustion Turbines	$ 98.7	$ 28.4	$ 273.2	$ 400.3
Valmy CTs Transmission	$ -	$ 0.5	$ 1.1	$ 1.6
Libra Transmission	$ 0.4	$ 0.8	$ 2.8	$ 4.0
Dry Lake East Transmission	$ 1.2	$ 2.9	$ -	$ 4.1
Transmission Infrastructure	$ 110.9	$ 150.1	$ 201.8	$ 462.8
Total Plan for Supply	$ 1,819.8	$ 1,155.1	$ 1,593.6	$ 4,568.4
Totals	$ 1,901.4	$ 1,243.9	$ 1,690.8	$ 4,836.0

SECTION V
CHANGES IN METHODOLOGY — NAC § 704.9489(1)(e)

While some modeling techniques have been improved, especially in the areas of load forecasting and DSM planning, and updates are described in the economic analysis narrative, the Companies are not proposing any changes in basic planning methodologies.

SECTION VI
ACQUISITION OF NEW MODELING INSTRUMENTS — NAC § 704.9489(l)(f)

In Section 7.C. of the Distributed Resources Plan, the Companies discuss the DER Analytics Toolset and Potential Study that introduces the new modeling instruments, DSMore and LoadSEER$_{TM}$, their purpose and utilization within this IRP, and planned future use. While some other modeling techniques have been improved, the Companies are not proposing any other new modeling instruments.

SECTION VII
DEMAND SIDE PLAN PROGRAMS — NAC § 704.9489(1)(g)

A description of continued planning efforts and the plan to carry out and continue selected conservation and DSM measures is set forth in Section II. The Companies have not attempted to claim or calculate imputed debt associated with energy efficiency contracts in the Preferred Plan.

SECTION VIII
ACQUISITION OF RESOURCES — NAC § 704.9489(1)(h)

During the Action Plan period, the Companies plan to enter into three PPAs for solar PV with storage generating resources totaling 1,028 MW with 1,028 MW of storage and construct two hydrogen-capable natural gas combustion turbines totaling 411 MW at the North Valmy Generating Station.

SECTION IX
RENEWABLE ENERGY ZONE TRANSMISSION PLAN – NAC §704.9489(5)

The Companies have prepared and previously submitted a Conceptual Renewable Energy Zone Transmission Plan (“REZTP”). The Companies did not produce new studies for the REZTP for this filing. Upon a new identification of renewable energy zones by the Commission, the Companies will revisit the REZTP and update accordingly.

SECTION X
ASSET RETIREMENT PLAN — NAC 704.9489(6)

Nevada Power and Sierra hold ownership interests in two generation assets that meet the criteria of NAC § 704.9489(5), specifically:

- <u>Mohave Generating Station – Nevada Power</u>: The Mohave site is in Laughlin, Nevada, and is the previous site of a 1,500 MW coal-fired generating plant. Nevada Power is a 14 percent owner in the project. Southern California Edison (majority owner and operator) and Los Angeles Department of Water and Power (who has assumed Salt River Project's original ownership share) are the other project owners. Mohave ceased operations January 1, 2006, and has been decommissioned.[1] In 2015, the co-owners agreed to proceed with selling most of the property through a public sale process. The project has been marketed for sale since 2016. If, and when, a transaction occurs and it is material, the net gains would be included in a future general rate case for the benefit of Nevada Power's customers. The owners will continue to retain approximately 500 acres of land and post-closure care associated with the closed onsite landfill.

- Navajo Generating Station – Nevada Power: The Navajo Generating Station is located near Page, Arizona, and is a previous site of a 2,250 MW total net capacity coal-fired facility. Nevada Power is a 11.3 percent participant in the Navajo Generating Station. Arizona Public Service, Los Angeles Department of Water and Power, Salt River Project, and Tucson Electric Power are other participants in the plant, with Salt River Project also holding an interest in Navajo on behalf of the United States. The coal-fired facility ceased operation in November 2019. Site decommissioning, demolition, pond, and landfill closure activities were completed in 2023. Site monitoring, post-closure care and groundwater monitoring activities, and extension lease payments will continue through the site remediation period ending December 22, 2054.

[1] As defined in NRS § 704.7332.

EXHIBIT B

The following is a list of the Integrated Resource Planning regulations and the document location where each regulation has been addressed.

Code	Sub-Section	Description	2024 IRP Location
NAC 704.9215		**NAC 704.9215 Summary of resource plan**. (NRS 703.025, 704.210, 704.741)	
NAC 704.9215	1	A utility's resource plan must be accompanied by a summary that is suitable for distribution to the pubic. The summary must contain easily interpretable tables, graphs and maps and must not contain any complex explanations or highly technical language. The summary must be approximately 40 pages in length.	Summary Volume
NAC 704.9215	2	The summary must include:	
NAC 704.9215	2(a)	A brief introduction, addressed to the public, describing the utility, its facilities and the purpose of the resource plan, and the relationship between the resource plan and the strategic plan of the utility for the duration of the period covered by the resource plan.	Summary Volume, Sections I and II (Executive Summary and Introduction to Companies)
NAC 704.9215	2(b)	The forecast of low growth, the forecast of high growth and the forecast of base growth of the peak demand for electric energy and of the annual electrical consumption, for the next 20 years, commencing with the year following the year in which the resource plan is filed, both with and without the impacts of programs for energy efficiency and conservation and an explanation of the economic and demographic assumptions associated with each forecast.	Summary Volume, Section III (Forecast of Growth)
NAC 704.9215	2(c)	A summary of the demand side plan listing each program and its effectiveness in terms of costs and showing the 20-year forecast of the reduction of demand and the contribution of each program to this forecast.	Summary Volume - Section IV (Demand Side Plan Summary)
NAC 704.9215	2(d)	A summary of the preferred plan:	
NAC 704.9215	2(d)(1)	Showing each planned addition to the system for the next 20 years, commencing with the year following the year in which the resource plan is filed, with its anticipated capacity, cost and date of beginning service; and	Summary Volume, Section V (Summary of the Preferred Plan)
NAC 704.9215	2(d)2	Explaining how the preferred plan reduces customer exposure to the price volatility of fossil fuels and the potential social cost of carbon as calculated pursuant to subsection 5 of NAC 704.937.	Summary Volume - Section V (Summary of the Preferred Plan)
NAC 704.9215	2(e)	A summary of renewable energy showing how the utility intends to comply with the portfolio standard and listing each existing contract for renewable energy and each existing contract for the purchase of renewable energy credits and the term and anticipated cost of each such contract.	Renewables Supply Plan Narrative, Sections 2 & 3, Technical Appendix REN-2
NAC 704.9215	2(f)	A summary of:	
NAC 704.9215	2(f)(1)	The energy supply plan for the next 3 years setting out the anticipated cost, price volatility and reliability risks of the energy supply plan;	Energy Supply Plan Volume
NAC 704.9215	2(f)(2)	The risk management strategy	Energy Supply Plan Volume, Section 7 (Risk Management Strategy)
NAC 704.9215	2(f)(3)	The fuel procurement plan	Energy Supply Plan Volume, Section5 (Gas Procurement Plan) and Section 6 (Coal Supply Plan)
NAC 704.9215	2(f)(4)	The purchased power procurement plan.	Energy Supply Plan Volume, Section 4 (Power Procurement Plan)
NAC 704.9215	2(g)	A summary of the distributed resources plan for the next 3 years covered by the action plan of the utility setting out:	Summary Volume - Section VIII (Distributed Resources Plan)
NAC 704.9215	2(g)(1)	The locational benefits and costs of the distributed resources, which may include benefits and costs to the electric grid	Summary Volume - Section VIII (Distributed Resources Plan)
NAC 704.9215	2(g)(2)	Identified barriers and recommendations to accept or overcome these barriers to the deployment of cost-effective distributed resources and proposed mechanisms pursuant to which cost-effective distributed resources will be deployed, in coordination with existing programs that have been approved by the Commission.	Summary Volume - Section VIII (Distributed Resources Plan)
NAC 704.9215	2(g)(3)	Incremental utility investment or expenditures to be funded for the next 3 years to identify, evaluate and integrate cost-effective distributed resources into the distribution planning process.	Summary Volume - Section VIII (Distributed Resources Plan)

NAC 704.9215	2(g)(4)	A summary of the methods and outcomes of the hosting capacity analysis described by paragraph (b) of subsection 3 of NAC 704.9237.	Summary Volume - Section VIII (Distributed Resources Plan)
NAC 704.9215	2(g)(5)	A summary of forecasted loads and the forecasted growth of distributed energy resources for the electric grid over a 6-year period, at minimum, beginning with the year after the distributed resources plan is filed.	Summary Volume - Section VIII (Distributed Resources Plan)
NAC 704.9215	2(h)	A summary of the activities, acquisitions and costs included in the action plan of the utility.	Summary Volume, Section IX (A Summary of the Activities, Acquisitions, and Costs Included in the Action Plan of the Utility); Exhibit A (Action Plan Budget)
NAC 704.9215	2(i)	An integrated evaluation of the components of the resource plan which relates the preferred plan to the objectives of the strategic plan of the utility, and any other information useful in presenting to the public a comprehensive summary of the utility and its expected development.	Summary Volume
NAC 704.922		**NAC 704.922 Technical appendix to resource plan.** (NRS 703.025, 704.210, 704.741)	
NAC 704.922	1	A utility's resource plan must include a technical appendix. The appendix must contain sufficient detail to enable a technically proficient reader to understand how the resource plan and its forecasts were prepared and to evaluate the validity of the assumptions and the accuracy of the data used, including, without limitation, a list of the major assumptions used, a description of the forecasting methods employed and a description of the software utilized.	The 2024 IRP includes a technical appendix with sufficient detail to enable a technically proficient individual to understand how the resource plan and its forecasts were prepared and to evaluate the validity of the assumptions and accuracy of the data used.
NAC 704.922	2	The appendix must contain sufficient information to enable a technically proficient reader to reproduce the results from the computations shown, including, without limitation:	
NAC 704.922	2(a)	Citations to the sources of all significant information used in the resource plan;	All Technical Appendix Items, including but not limited to MF; FPP; LF; DSM; DRP; TEP; GEN; REN; TRAN; ECON; FIN
NAC 704.922	2(b)	Descriptions of all data inputs to the models used in developing the resource plan accompanied by an explanation of any modifications made to the data;	All Technical Appendix Items, including but not limited to MF; FPP; LF; DSM; DRP; TEP; GEN; REN; TRAN; ECON; FIN
NAC 704.922	2(c)	Characteristics of the generation operation of the utility, including the:	
NAC 704.922	2(c)(1)	Rates of forced outages;	Technical Appendix Item GEN-1 (Unit Characteristics Table)
NAC 704.922	2(c)(2)	Rates of scheduled outages;	Technical Appendix Item GEN-1 (Unit Characteristics Table)
NAC 704.922	2(c)(3)	Heat rates;	Technical Appendix Item GEN-1 (Unit Characteristics Table)
NAC 704.922	2(c)(4)	Rates at which pollutants are emitted;	Technical Appendix Item GEN-2 (Emissions Rates - Generation)
NAC 704.922	2(c)(5)	Controls required to mitigate pollution at planned facilities and estimates of the costs of those controls; and	Supply Plan Narrative, Section 2.A.3 (Status of Previously Approved Projects)
NAC 704.922	2(c)(6)	Projections for the availability and price of fuels.	Technical Appendix Item FPP-1
NAC 704.922	2(d)	Output characteristics or profiles of renewable resources for each type of renewable resource that is being considered as a resource option or that is currently owned or under contract with the utility;	Technical Appendix Items REN-1 (Proposed Projects Supply Tables); REN-2 Renewable Portfolio Standard Buildout Scenarios; ECON-10 (Candidate Resources)
NAC 704.922	2(e)	A summary of the impact of intermittent energy resources on the electric system of the utility;	Technical Appendix ECON-5 (Loads and Resources Table)

NAC 704.922	2(f)	The final results derived from the models;	Technical Appendices: LF-1 2024 IRP Load Forecast; REN-1 (Proposed Projects Supply Tables), REN-2 Renewable Portfolio Standard Buildout Scenarios; ECON-3 (Average Generation Costs for Preferred Plan); ECON-4 (Summary of Production Cost Output for All Cases); ECON-6 Capital Projects; ECON-7 (PWRR); ECON-11 (Average Marginal Energy Costs for Preferred Plan); ECON-15 (DSM Cases); ECON-16 (No Greenlink Illustrative Case); FPP-1 Fuel and Purchased Power Price Forecasts
NAC 704.922	2(g)	Documentation of all models and formulas used consistent with any proprietary requirements imposed upon the utility by outside suppliers of the models;	Technical Appendices: DSM-1 Ace Guru, DSM-2 DSMore; DSM-4 M&V Process, DSM-5 through DSM-15 M&V Reports, DSM-16 Technical Appendix to M&V, DSM-21 through DSM-23 Net to Gross, DSM-24 DSM Market Potential Study; ECON-2 Description of Modeling Software; ECON-9 NERA Report; ECON-12 2024 Resource Adequacy Study; LF-1 2024 IRP Load Forecast
NAC 704.922	2(h)	Such other information as is necessary to enable an informed reader to examine the resource plan and verify the adequacy and accuracy of the data, assumptions and methods used in developing the resource plan.	The Technical Appendix includes additional information that the Company believes will be useful in examining the resource plan.
NAC 704.9225		**NAC 704.9225 Forecasts of peak demand and annual energy consumption: General requirements.** (NRS 703.025, 704.210, 704.741)	
NAC 704.9225	1	A utility's resource plan must contain a series of forecasts of the peak demand and annual energy consumption that represent the range of future load which its system may be required to serve. The range of future peak demand and energy consumption must be based upon and consistent with the upper and lower limits of expected economic and demographic change in the utility's service territory in the next 20 years, commencing with the year following the year in which the resource plan is filed, as follows	
NAC 704.9225	1(a)	A forecast of high growth;	LF-1 2024 IRP Load Forecast; LF Technical Appendix Section V
NAC 704.9225	1(b)	A forecast of base growth; and	LF-1 2024 IRP Load Forecast; LF Technical Appendix Section V
NAC 704.9225	1(c)	A forecast of low growth.	LF-1 2024 IRP Load Forecast; LF Technical Appendix Section V
NAC 704.9225	2	In each of the forecasts described in subsection 1, the utility shall account for customer response to changes in the prices of electric energy and substitute energy sources and to the impacts of existing and proposed programs undertaken by the utility or required by governmental regulation to alter current energy use patterns.	LF-1 2024 IRP Load Forecast; LF Technical Appendix Section IV
NAC 704.9225	3	To the extent data is available, peak demand must be forecasted before accounting for the effects of cogeneration.	LF-1 2024 IRP Load Forecast; LF Technical Appendix Section IV
NAC 704.9225	4	The utility shall maintain internal consistency among its forecasts. The forecast of peak demand must be consistent with the forecast of energy consumption and must be based on data which is normalized for weather pursuant to NAC 704.9245.	Technical Appendix LF-1, Section III
NAC 704.923		**NAC 704.923 Periods to be covered by resource plan.** (NRS 703.025, 704.210, 704.741) The periods that must be covered by the utility's resource plan are as follows:	
NAC 704.923	1	For historical data, the 10-year period preceding the year in which the resource plan is filed. If estimated data are used, the utility shall identify such data and describe the procedure by which the estimates were made.	Technical Appendix LF-1, Section III
NAC 704.923	2	For the forecasts of peak demand and energy consumption, the 20-year period beginning with the year in which the resource plan is filed.	Technical Appendix LF-1, Section IV
NAC 704.9235		**NAC 704.9235 Formats for information included in resource plan.** (NRS 703.025, 704.210, 704.741)	

NAC 704.9235	1	A utility shall, in consultation with the staff and subject to the approval of the Commission, develop suitable formats to be used for all information required in the resource plan of the utility.	This filing is consistent with past filings in terms of formatting in accordance with Commission regulations. The Companies provide executable copies of non-confidential filing documents to Staff and BCP upon request.
NAC 704.9235	2	Graphical and tabular information must be accompanied by explanatory narratives.	All graphical and tabular information is accompanied by explanatory narratives.
NAC 704.9235	3	A resource plan may include text which is not specifically related to those formats but is of importance to the resource plan.	This Companies' Joint IRP filing includes text which is of importance to the proposed plan.
NAC 704.9237		**NAC 704.9237 Requirements and contents of distributed resources plan; identification and justification of certain changes of methodology; public posting of update to hosting capacity analysis.** (NRS 703.025, 704.210, 704.741)	
NAC 704.9237	1	The resource plan of a utility must contain a distributed resources plan for the 3 years covered by the action plan of the utility. The distributed resources plan of a utility must be consistent with the action plan of the utility.	The 2024 IRP includes a Distributed Resources Plan (DRP) for the 3 years covered by the IRP action plan, and the DRP is consistent with the IRP action plan.
NAC 704.9237	2	The distributed resources plan must:	
NAC 704.9237	2(a)	Identify and evaluate the locational benefits and costs of distributed resources. The evaluation must be based on:	DRP Narrative, Sections 3.A.3.b, 3.A.3.c, 3.B.3.b, 3.B.3.c
NAC 704.9237	2(a)(1)	Reductions or increases in local generation capacity needs;	DRP Narrative, Sections 3.A.3.b, 3.A.3.c, 3.B.3.b, 3.B.3.c
NAC 704.9237	2(a)(2)	Avoided or increased localized investments in distribution infrastructure;	DRP Narrative, Sections 3.A.3.b, 3.A.3.c, 3.B.3.b, 3.B.3.c
NAC 704.9237	2(a)(3)	Reductions or increases in safety benefits of the electric grid;	DRP Narrative, Sections 3.A.3.b, 3.A.3c, 3.B.3.b, 3.B.3.c
NAC 704.9237	2(a)(4)	Reductions or increases in the reliability benefits of the electric grid;	DRP Narrative, Sections 3.A.3.b, 3.A.3c, 3.B.3.b, 3.B.3.c
NAC 704.9237	2(a)(5)	Any other localized savings that the distributed resources provide to the electric grid; and	DRP Narrative, Sections 3.A.3.b, 3.A.3c, 3.B.3.b, 3.B.3.c
NAC 704.9237	2(a)(6)	Any other costs that distributed resources impose on customers of the electric utility or utilities.	DRP Narrative, Sections 3.A.3.b, 3.A.3c, 3.B.3.b, 3.B.3.c
NAC 704.9237	2(b)	As part of the distributed resources plan, the utility may propose tariffs, bilateral contracts, competitive solicitations or other mechanisms that it has identified and evaluated that maximize locational benefits and minimize the incremental cost of distributed resources.	DRP Narrative, Sections 5.B and 8.A.2
NAC 704.9237	2(c)	Identify existing programs approved by the Commission that address the deployment of distributed resources, including, without limitation, tariffs and incentives, and propose cost-effective methods of effectively coordinating the deployment of distributed resources with such existing programs to maximize the locational benefits and minimize the incremental costs of distributed resources.	DRP Narrative, Section 5.B
NAC 704.9237	2(d)	Identify and evaluate any incremental utility investment or expenditure necessary to integrate cost-effective distributed resources into the distribution planning process consistent with the goal of yielding a net benefit to the customers of the electric utility or utilities.	DRP Narrative, Section 7
NAC 704.9237	2(e)	Identify and evaluate potential barriers to the deployment of distributed resources, including, without limitation, safety standards related to technology or operation of the distribution system and make recommendations regarding accepting or overcoming identified potential barriers in a manner that will ensure the safety of the distribution grid and the reliability of service.	DRP Narrative, Section 4
NAC 704.9237	2(f)	Be developed by a utility using a forecast of net distribution system load and distributed resources. The forecast must be for a period of not less than 6 years, beginning with the year after the distributed resources plan is filed. The net distribution system load and distributed resources forecast will include system, substation and feeder level net load projections and energy and demand characteristics for all distributed resource types.	DRP Narrative, Sections 3.A.1 and 3.B.1; Technical Appendix DRP-4
NAC 704.9237	3	The distributed resources plan must include:	

NAC 704.9237	3(a)	A grid needs assessment, which must be based on the net distribution system load, distributed resource forecast and the facilities capacity analysis. The grid needs assessment must include, without limitation:	DRP Narrative, Sections 3.A.3 and 3.B.3
NAC 704.9237	3(a)(1)	The hosting capacity analysis described by paragraph (b);	DRP Narrative, Section 3.A.2
NAC 704.9237	3(a)(2)	An analysis of the suitability of non-wires alternatives to mitigate identified transmission and distribution system constraints;	DRP Narrative, Sections 3.A.3.b and 3.B.3.b
NAC 704.9237	3(a)(3)	A locational net benefit analysis to compare utility infrastructure upgrade solutions and distributed resources solutions to forecasted transmission and distribution system constraints; and	DRP Narrative, Sections 3.A.3.c and 3.B.3.c
NAC 704.9237	3(a)(4)	Recommendations for the deployment of utility infrastructure upgrade solutions and non-wires alternative solutions to identified transmission and distribution system constraints.	DRP Narrative, Sections 3.A.3.d and 3.B.3.d
NAC 704.9237	3(b)	A hosting capacity analysis of the distribution system. The hosting capacity analysis shall be performed using a load flow analysis and forecasted distribution facilities and their capacity, configuration, loading and voltage data gathered at the substation, feeder and primary node levels. The utility shall perform scenario analyses to evaluate hosting capacity under normal conditions and planned and unplanned contingency conditions. The utility shall provide a detailed description of the methods and outcomes it used to perform the hosting capacity analysis. The utility shall also provide a detailed narrative describing the utility's progress towards providing publicly-available, real-time hosting capacity data.	DRP Narrative, Section 3.A.2
NAC 704.9237	3(c)	Recommendations for new cost-effective distributed resources, sourcing of distributed resource solutions and utility infrastructure upgrade solutions which have been determined to be the preferred solution to constraints on a utility's electric grid on the basis of the analysis in the grid needs assessment. Such recommendations must be based on the locational net benefit analysis of resource options to utility customers.	DRP Narrative, Sections 3.A.3.d and 3.B.3.d
NAC 704.9237	3(d)	A summary that explains how distributed resources have affected the need for supply side resources in the resource planning process. The summary shall include, without limitation, a description of the effect of distributed resources on the need for new generation and transmission resources and how distributed resources are integrated into the transmission planning and supply side planning portions of the resource planning process.	DRP Narrative, Section 5.A
NAC 704.9237	3(e)	A summary that describes the results of an informal stakeholder process to discuss recommendations for improvements to the hosting capacity analysis. The informal stakeholder process shall occur not less than 120 days before the filing of a distributed resources plan and be organized by the utility.	DRP Narrative, Section 2.D
NAC 704.9237	3(f)	A technical appendix that conforms to the requirements of NAC 704.922.	Technical Appendices DRP-1 through DRP-10 and TEP-1 through TEP-6
NAC 704.9237	3(g)	A plan to accelerate transportation electrification in this State that:	
NAC 704.9237	3(g)(1)	Complies with the requirements of NRS 704.7867; and	DRP Narrative, Section 10
NAC 704.9237	3(g)(2)	Includes all financial impacts associated with the plan and separately identifies the financial impacts of any proposed financial incentives or special accounting treatment requested, including, without limitation, a rate impact analysis that specifies the rate impact of any such proposal on each rate class.	DRP Narrative, Section 10
NAC 704.9237	4	If the utility changes the methodology of forecasting or the methodology used to conduct the hosting capacity analysis or grid needs assessment from the methodology used in the previous resource plan filed by the utility, the utility shall identify and provide a justification for the change.	DRP Narrative, Sections 3.A.1, 3.A.2, and 3.B.1
NAC 704.9237	5	Unless otherwise ordered by the Commission, in addition to, and separately from, the updates required pursuant to NAC 704.9239, the utility shall, not less than once per year, post publicly on its Internet website an update to the hosting capacity analysis of the distribution system. The Internet website of the utility shall contain a portal that provides maps and accessible electronic data suitable for distribution to the public.	DRP Narrative, Sections 3.A.2 and 6

NAC 704.9237	6	To the extent that a plan to accelerate transportation electrification submitted pursuant to paragraph (g) of subsection 3 includes programs in which customers may participate, eligibility for participation by customers in such programs must be offered by the utility on a nondiscriminatory basis to both bundled retail customers and eligible customers, as defined in NRS 704B.080, who purchase or plan to purchase electricity from a provider of new electric resources, as defined in NRS 704B.130. Before eligible customers who purchase or plan to purchase electricity from a provider of new electric resources may participate in such programs, the utility shall request, and the Commission may approve, a non-bypassable per kilowatt hour charge to fully pay for the participation of eligible customers who purchase or plan to purchase electricity from a provider of new electric resources.	DRP Narrative, Section 10
NAC 704.9238		**NAC 704.9238 Deviation from and amendment of distributed resources plan.** (NRS 703.025, 704.210, 704.741)	
NAC 704.9238	1	Notwithstanding the approval of the Commission of the distributed resources plan of a utility, the utility may deviate from the approved distributed resources plan to the extent necessary to respond adequately to any significant change in circumstances not contemplated by the distributed resources plan. A significant change in circumstances includes, without limitation:	No requirement in this filing
NAC 704.9238	1(a)	A material change in net system, feeder or nodal customer load or demand;	No requirement in this filing
NAC 704.9238	1(b)	A material difference between the estimated and actual locational net benefit results for any or all resources analyzed in the grid needs assessment;	No requirement in this filing
NAC 704.9238	1(c)	A material difference between estimated and actual in-service dates or performance of the distributed resources analyzed and selected pursuant to the distributed resources plan;	No requirement in this filing
NAC 704.9238	1(d)	Any other circumstance that the utility demonstrates to the Commission warrants a deviation.	No requirement in this filing
NAC 704.9238	2	If the utility deviates from its approved distributed resources plan, the utility shall include in the rate proceeding in which costs associated with the deviation are first sought to be recovered a description and justification for the deviation.	No requirement in this filing
NAC 704.9238	3	The utility may seek authority from the Commission to deviate prospectively from the distributed resources plan in an update filed pursuant to NAC 704.9239, or by filing an amendment to the distributed resources plan in accordance with subsection 4.	No requirement in this filing
NAC 704.9238	4	An amendment to the distributed resources plan of a utility must contain:	
NAC 704.9238	4(a)	A section that identifies the specific approvals requested by the utility in the amendment;	No requirement in this filing
NAC 704.9238	4(b)	A section that specifies any changes in assumptions or data that have occurred since the utility's last resource plan was filed; and	No requirement in this filing
NAC 704.9238	4(c)	As applicable, information required by NAC 704.9237.	No requirement in this filing
NAC 704.9238	5	The Commission shall conduct its evaluation of the amendment of the distributed resources plan in accordance with subsection 5 of NAC 704.9494 and issue an order approving the amendment as filed, modifying the amendment or specifying any portions of the amendment that the Commission deems to be inadequate.	
NAC 704.9239		**NAC 704.9239 Update of distributed resources plan: Filing; requirements.** (NRS 703.025, 704.210, 704.741)	
NAC 704.9239	1	Beginning in calendar year 2020, on or before September 1 of the first and second years after the action plan of a utility is filed, the utility shall file an update of the distributed resources plan that will be applicable for each year remaining in the period covered by the action plan.	No requirement in this filing
NAC 704.9239	2	The update of the distributed resources plan must comply with the requirements of NAC 704.9237.	No requirement in this filing
NAC 704.9241		**NAC 704.9241 Update of distributed resources plan: Action by Commission.** (NRS 703.025, 704.210, 704.741)	
NAC 704.9241	1	The Commission will conduct a hearing within 60 days after a utility files an update of its distributed resources plan pursuant to NAC 704.9239 and issue an order within 120 days after the filing of that update by the utility.	No requirement in this filing

NAC 704.9241	2	The Commission will conduct its evaluation of the update of the distributed resources plan in accordance with subsection 5 of NAC 704.9494 and issue an order approving the update as filed, modifying the update or specifying any portions of the update that the Commission deems to be inadequate.	No requirement in this filing
NAC 704.9245		**NAC 704.9245 Normalizing forecast values of peak demand and energy consumption to account for normal weather conditions.** (NRS 703.025, 704.210, 704.741) All forecast values of peak demand and energy consumption must be normalized to account for normal weather conditions within the service territory of the utility.	Technical Appendix LF-1, Section III
NAC 704.925		**NAC 704.925 Resource plan: Inclusion, contents and evaluation of forecasts of energy consumption and peak demand; consideration of certain impacts; identification of change in methodology of forecasting.** (NRS 703.025, 704.210, 704.741)	
NAC 704.925	1	A utility's resource plan must include forecasts of energy consumption and the peak demand for summer and winter for the system, disaggregated by rate schedule, for the 20-year period beginning with the year following the year in which the resource plan is filed. The utility may combine rate schedules if necessary to protect the confidentiality of individual customers.	Technical Appendix LF-1, Section IV
NAC 704.925	2	The utility shall identify components of residential and commercial energy and demand for which initiatives for energy efficiency and conservation are applicable. The utility shall include in its forecast an assessment of the impacts of such initiatives on the identified components and on overall levels of energy consumption and demand by residential and commercial customers.	Technical Appendix LF-1, Section IV
NAC 704.925	3	The utility's forecast must include:	
NAC 704.925	3(a)	Estimated annual losses of energy on the system for the 20-year period of the resource plan; and	Technical Appendix LF-1, Section III
NAC 704.925	3(b)	Estimated annual energy to be used by the utility for the 20-year period of the resource plan.	Technical Appendix LF-1, Section III
NAC 704.925	4	The utility shall consider the impact of applicable new technologies and the impact of applicable new governmental programs or regulations.	Technical Appendix LF-1, Section III
NAC 704.925	5	The utility shall consider the impact of distributed generation and customers who acquire energy pursuant to NRS 704.787 or chapter 704B of NRS.	Technical Appendix LF-1, Section III
NAC 704.925	6	The utility shall provide a reasonable estimate of the demand from interruptible loads and the total demand of each type of interruptible load.	Technical Appendix LF-1, Section III
NAC 704.925	7	The utility shall identify all standby loads and the total demand of each type of standby load and include an analysis of the likelihood and effect of incurring such demands at the time of the system peak of the utility.	Technical Appendix LF-1, Section III
NAC 704.925	8	All forecast values for the entire system of the utility must be reported. The utility shall separately estimate the contribution to peak demand and energy consumption for the components of the system located within the State of Nevada and for the components of the system located outside the State of Nevada.	Technical Appendix LF-1, Section III
NAC 704.925	9	A resource plan must contain a graphical representation of projected load duration curves for the year following the year in which the resource plan was filed and every fifth year thereafter for the remainder of the period covered by the resource plan.	Technical Appendix LF-1, Section IV
NAC 704.925	10	To verify and complete the final forecasts, the utility may evaluate the forecasts with the results of alternative forecasting methods.	No alternative models were evaluated.
NAC 704.925	11	Any change in the methodology of forecasting used by the utility from that used in the utility's previous resource plan must be identified in the current resource plan of the utility.	Testimony of Tim Pollard
NAC 704.9281		**NAC 704.9281 Resource plan: Contents of data relating to peak demand and energy consumption.** (NRS 703.025, 704.210, 704.741)	
NAC 704.9281	1	The historical data relating to peak demand and energy consumption submitted in a utility's resource plan must contain:	
NAC 704.9281	1(a)	The recorded and coincident peak demand, normalized for weather, in the summer and winter for the total system for the 10-year period immediately preceding the year in which the resource plan is filed;	Technical Appendix LF-1, Section III
NAC 704.9281	1(b)	The recorded and annual sales of energy consumption, normalized for weather, for the total system for each year of the 10-year period immediately preceding the year in which the resource plan is filed;	Technical Appendix LF-1, Section III

NAC 704.9281	1(c)	The estimated losses of energy for the system for each year of the 10-year period immediately preceding the year in which the resource plan is filed; and	Technical Appendix LF-1, Section III
NAC 704.9281	1(d)	The estimated or actual amount of electric energy used by the utility in the operation of its business for each year of the 10-year period immediately preceding the year in which the resource plan is filed.	Technical Appendix LF-1, Section III
NAC 704.9281	2	The data on energy consumption and peak demands must include data on all consumption and demands of ultimate customers that reflect firm, contractual commitments.	Technical Appendix LF-1, Sections III and IV
NAC 704.9321		**NAC 704.9321 Resource plan: Reliability of assumptions, forecasts, conclusions and information; adjustments to forecasts; maps of covered areas; supportive testimony.** (NRS 703.025, 704.210, 704.741)	
NAC 704.9321	1	To the extent consistent with cost-effective procedures generally accepted by the industry, all assumptions, forecasts, conclusions and information used by a utility in its resource plan must be:	
NAC 704.9321	1(a)	Based on substantially accurate data;	The assumptions, forecasts, conclusions and information used in this filing meet these requirements.
NAC 704.9321	1(b)	Adequately demonstrated and defended; and	The assumptions, forecasts, conclusions and information used in this filing meet these requirements.
NAC 704.9321	1(c)	Adequately documented and justified.	The assumptions, forecasts, conclusions and information used in this filing meet these requirements.
NAC 704.9321	2	Adjustments to forecasts obtained from external or published sources that are made on the basis of factors specifically relating to the utility must be explained.	Load Forecast Appendices LF-1 through LF-8
NAC 704.9321	3	Each utility shall provide a suitable map or maps to show all areas covered by the resource plan. Each such map must show at least:	
NAC 704.9321	3(a)	The service territory covered by the resource plan;	Summary Volume, Figure S-7 (NV Energy Service Territories)
NAC 704.9321	3(b)	The locations of the utility's facilities for generation of electric energy;	Supply Plan Narrative, Section 2.A.1 (Existing Generation)
NAC 704.9321	3(c)	The location of renewable resources, independent power producers and distributed generation that are located within the service territory of the utility and are under contract with the utility;	Supply Plan Narrative, Section B
NAC 704.9321	3(d)	The interconnections with other utilities and independent power producers; and	Transmission Narrative, Section B, Transmission Path Ratings and Transmission Service Obligations
NAC 704.9321	3(e)	The utility's facilities for transmission of electric energy.	Transmission Narrative, Section B, Overview of the Companies' Transmission System
NAC 704.9321	4	All testimony offered in support of the resource plan must be filed with the resource plan.	All of the testimony offered in support of the 2021 Joint IRP is filed with the 2021 Joint IRP Plan.
NAC 704.934		**NAC 704.934 Preparation, contents and submission of demand side plan; annual analyses regarding programs for energy efficiency and conservation.** (NRS 703.025, 704.210, 704.741, 704.7836)	
NAC 704.934	1	As part of its resource plan, a utility shall submit a demand side planthat is cost effective as a whole.	DSM Plan Narrative and Technical Appendices DSM-1 through DSM-29
NAC 704.934	2	The demand side plan must include:	
NAC 704.934	2(a)	An identification of end-uses for programs for energy efficiency and conservation.	DSM Narrative Sections 4-6
NAC 704.934	2(b)	An assessment of savings attributable to technically feasible programs for energy efficiency and conservation, as determined by the utility. The programs must be ranked in a list according to the level of savings in energy or reduction in demand, or both.	DSM Narrative Sections 3-6
NAC 704.934	2(c)	An assessment of technically feasible programs to determine which will produce benefits in peak demand or energy consumption. The utility shall estimate the cost of each such program. The methods used for the assessment must be stated in detail, specifically listing the data and assumptions considered in the assessment.	DSM Narrative Sections 3-6

NAC 704.934	2(d)	An energy efficiency plan which complies with the requirements of NRS 704.7836, and which includes any additional goals for energy savings established by the Commission.	DSM Narrative Section 1
NAC 704.934	3	In creating its demand side plan, a utility shall consider the impact of applicable new technologies on current and future energy efficiency and conservation options. The consideration of new technologies must include, without limitation, consideration of the potential impact of advances in digital technology and computer information systems.	DSM Narrative Section 3, and Section 4 "Program Development" data sheet
NAC 704.934	4	A utility shall include in its demand side plan an energy efficiency program for residential customers which reduces the consumption of electricity or any fossil fuel. The energy efficiency program must include, without limitation, the use of new solar thermal energy sources.	DSM Narrative Section 3; Gas C&EE Plan Narrative
NAC 704.934	5	The demand side plan must provide a list of the programs for which the utility is requesting the approval of the Commission. The list must include, without limitation:	
NAC 704.934	5(a)	An estimate of the reduction in the peak demand and energy consumption that would result from each proposed program, in kilowatt-hours and kilowatts saved. The programs must be listed according to their expected savings and their contribution to a reduction in peak demand and energy consumption based upon realistic estimates of the penetration of the market and the average life of the programs.	DSM Narrative Sections 2-3; Technical Appendices DSM-5 through DSM-15 (M&V Reports)
NAC 704.934	5(b)	An assessment of the costs of each proposed program and the savings produced by the program. If the program can be relied upon to reduce peak demand on a firm basis, the assessment must include the savings in the costs of transmission and distribution.	DSM Narrative Sections 1 and 4-6; Technical Appendices DSM-5 through DSM-15 (M&V Reports)
NAC 704.934	5(c)	An assessment of the impact on the utility's load shapes of each proposed and existing program for energy efficiency and conservation.	DSM Narrative Section 3; Technical Appendices DSM-5 through DSM-15 (M&V Reports)
NAC 704.934	5(d)	If a program is an educational program, the projected expenses of the utility for the educational program.	DSM Narrative Section 4 (Education Program)
NAC 704.934	6	For any energy efficiency or conservation program which reduces the consumption of electricity or any fossil fuel, a utility shall include in its demand side plan a complete life-cycle analysis of the costs and benefits of the program using at least one standard test of cost effectiveness that accounts for the nonenergy benefits of the program.	DSM Narrative Sections 3-6, DSM Technical Appendices
NAC 704.934	7	The utility shall include with its demand side plan a report on the status of all programs for energy efficiency and conservation that have been approved by the Commission. The report must include tables for each such program showing, for each year, the planned and achieved reduction in kilowatt-hours, the reduction in kilowatts and the cost of the program.	DSM Narrative Sections 2 and 4-6
NAC 704.934	8	Not less than 10 percent of the total expenditures related to energy efficiency and conservation programs in the demand side plan must be directed to energy efficiency measures for customers of the electric utility in low-income households and residential customers and public schools in historically underserved communities through both targeted programs and programs directed at residential customers and public schools in general.	DSM Narrative Sections 2-3; DSM Technical Appendices
NAC 704.934	9	On or before July 1 of each year following the filing of its resource plan, the utility shall file with the Commission a copy of the complete analysis the utility used in determining for the upcoming year which energy efficiency and conservation programs are to be continued and which programs are to be cancelled. Within 180 days after the analysis is filed, the Commission will accept the analysis as filed, accept the analysis with modification or reject the analysis.	DSM Narrative, Sections 2 and 4-6
NAC 704.934	10	As used in this section:	
NAC 704.934	10(a)	"Energy efficiency and conservation program" has the meaning ascribed to it in NRS 704.7366.	
NAC 704.934	10(b)	"Energy savings" has the meaning ascribed to it in NRS 704.7834.	
NAC 704.934	10(c)	"Historically underserved community" has the meaning ascribed to it in NRS 704.78343.	

NAC 704.934	10(d)	"New solar thermal energy sources" means energy sources which are installed after the effective date of the utility's energy efficiency program and which reduce the consumption of electricity or any fossil fuel by using solar radiation to heat water or to provide space heating or cooling.	
NAC 704.9355		**NAC 704.9355 Analyses of options for supply** (NRS 703.025, 704.210, 704.741)	
NAC 704.9355	1	A utility shall develop a set of analyses of its options for supply to be considered for meeting the expected future demand on its system. These analyses must include an examination of the environmental impact of each option, taking into account the best available technologies and the environmental benefit of renewable resources. The options to be analyzed must include:	
NAC 704.9355	1(a)	Construction of new generation facilities or upgrades to existing generation facilities, including retrofitting existing facilities with more efficient systems or converting to other fuels;	Supply Plan Narrative, Section 2.4.a. (Valmy Simple Cycle Plant)
NAC 704.9355	1(b)	Construction of new transmission facilities or upgrades to existing transmission facilities;	Transmission Plan Narrative, Section C
NAC 704.9355	1(c)	Purchase of long-term transmission rights on transmission facilities owned by other persons;	Transmission Plan Narrative, Section B, FIGURE TP-14 and FIGURE TP-15
NAC 704.9355	1(d)	Improvements in the efficiency of operations and scheduling, including, without limitation, improvements that are attributable to the proposed implementation of new digital and computer information system technologies;	Not Applicable
NAC 704.9355	1(e)	Options of low carbon dioxide emissions; and	Supply Plan Narrative, Section 3.E
NAC 704.9355	1(f)	Transactions with other utilities, independent producers and utility customers for:	
NAC 704.9355	1(f)(1)	Pooling of power;	Supply Plan Narrative, Sections 3.B and 3.E
NAC 704.9355	1(f)(2)	Purchases of power; or	Supply Plan Narrative, Sections 3.B and 3.E
NAC 704.9355	1(f)(3)	Exchanges of power.	Supply Plan Narrative, Sections 3.B and 3.E
NAC 704.9355	2	As used in this section, "environmental benefit of renewable resources" means the present worth over a 20-year period of the benefits associated with the generation and maintenance of renewable resources for supply of capacity or energy, or supply of both capacity and energy, that results in a reduction of harm to the environment.	
NAC 704.9357		**NAC 704.9357 Analysis of net economic benefits to State.** (NRS 703.025, 704.210, 704.741)	
NAC 704.9357	1	An analysis of the changes that result in net economic benefits to Nevada from electricity-producing or electricity-saving resources must be conducted by the utility in selecting a resource option. The net economic benefit to the State must be quantified to reflect both the positive and negative changes and must include the net economic impact of renewable resources. The projected present worth of societal cost of a competing resource plan must be within 10 percent of the lowest societal costs plan before proceeding with an analysis of the economic benefits to Nevada.	Supply Plan Narrative, Section 3.G (Environmental Externalities and Net Economic Benefits); Technical Appendix ECON-9 (NERA Report)
NAC 704.9357	2	The economic benefits analysis must be achieved by calculating the portion of the present worth of future requirements for revenue that is expended within the State, including the following for both the construction and operation phases of any project:	Supply Plan Narrative, Section 3.G (Environmental Externalities and Net Economic Benefits); Technical Appendix ECON-9 (NERA Report)
NAC 704.9357	2(a)	Capital expenditures for land and facilities located within the State or equipment manufactured in the State;	Supply Plan Narrative, Section 3.G (Environmental Externalities and Net Economic Benefits); Technical Appendix ECON-9 (NERA Report)
NAC 704.9357	2(b)	The portion of the cost of materials, supplies and fuel purchased in the State;	Supply Plan Narrative, Section 3.G (Environmental Externalities and Net Economic Benefits); Technical Appendix ECON-9 (NERA Report)

NAC 704.9357	2(c)	Wages paid for work done within the State;	Supply Plan Narrative, Section 3.G (Environmental Externalities and Net Economic Benefits); Technical Appendix ECON-9 (NERA Report)
NAC 704.9357	2(d)	Taxes and fees paid to the State or subdivisions thereof; and	Supply Plan Narrative, Section 3.G (Environmental Externalities and Net Economic Benefits); Technical Appendix ECON-9 (NERA Report)
NAC 704.9357	2(e)	Fees paid for services performed within the State.	Supply Plan Narrative, Section 3.G (Environmental Externalities and Net Economic Benefits); Technical Appendix ECON-9 (NERA Report)
NAC 704.9357	3	In the analysis, the utility shall consider only the net benefit added to the economy of the State of that portion of expenditures made within the State.	Supply Plan Narrative, Section 3.G (Environmental Externalities and Net Economic Benefits); Technical Appendix ECON-9 (NERA Report)
NAC 704.9357	4	The present worth of societal costs of the competing resources must then be adjusted by the Commission to take into consideration either all, or only a portion, of the calculated economic benefit."	Supply Plan Narrative, Section 3.G (Environmental Externalities and Net Economic Benefits); Technical Appendix ECON-9 (NERA Report)
NAC 704.9357	5	As used in this section, "net economic impact of a renewable resource" means the present worth of economic costs of a contract for a renewable resource minus the present worth of economic development benefits to the State over a 20-year period.	
NAC 704.9359		**NAC 704.9359 Determination of environmental costs to State.** (NRS 703.025, 704.210, 704.741) The environmental costs to the State associated with operating and maintaining a supply plan or demand side plan must be quantified for air emissions, water and land use and the social cost of carbon as calculated pursuant to subsection 5 of NAC 704.937. Environmental costs are those costs, wherever they may occur, that result from harm or risks of harm to the environment after the application of all mitigation measures required by existing environmental regulation or otherwise included in the resource plan.	Supply Plan Narrative, Section 3.G (Environmental Externalities and Net Economic Benefits); Technical Appendix ECON-9 (NERA Report)
NAC 704.9361		**NAC 704.9361 Elimination or modification of environmental factors, emission rates and environmental costs** (NRS 703.025, 704.210, 704.741) The emission rates and environmental costs set or otherwise authorized by the Commission may be subject to elimination or modification, and new factors may be added for consideration, as new scientific, engineering, economic or other technical information becomes available to the Commission. Information purporting to establish a need for the deletion or addition of any environmental factor or the revision of any authorized emission rates or environmental costs may be presented by any party at the time of a hearing on the utility's resource plan.	The Company is not claiming a need for the deletion or addition of any environmental factor or the revision of any authorized emission rates or environmental costs.
NAC 704.937		**NAC 704.937 Inclusion in supply plan of alternative plans and list of options for supply of capacity and electric energy; criteria for selection of options; comparison of and requirements for alternative plans; identification of preferred plan.** (NRS 703.025, 704.210, 704.741)	
NAC 704.937	1	A utility's supply plan must contain a diverse set of alternative plans which include a list of options for the supply of capacity and electric energy that includes a description of all existing and planned facilities for generation and transmission, existing and planned power purchases, and other resources available as options to the utility for the future supply of electric energy. The description must include the expected capacity of the facilities and resources for each year of the supply plan. At least one alternative plan must be of low carbon dioxide emissions that:	Supply Plan Narrative, Section 2 (Supply Side Plan); Supply Plan Narrative, Section 3.E. (Plan Development); Technical Appendix Items ECON-5 (Loads and Resources Tables);
NAC 704.937	1(a)	Uses sources of supply that result in, by 2050, an amount of energy production from zero carbon dioxide emission resources that equals the forecasted demand for electricity by customers of the utility;	Supply Plan Narrative, Section 3.E. (Plan Development)
NAC 704.937	1(b)	Includes the deployment of distributed generation; and	DRP Narrative

NAC 704.937	1(c)	If the plan is submitted on or before June 1, 2027, uses sources of supply that result in, by the year 2030, an 80 percent reduction in carbon dioxide emissions from the generation of electricity to meet the demands of customers of the utility as compared to the amount of such emissions in the year 2005.	Supply Plan Narrative, Section 3.E. (Plan Development)
NAC 704.937	2	A utility shall identify the criteria it has used for the selection of its options for meeting the expected future demands for electric energy and shall explain how any conflicts among criteria are resolved.	Supply Plan Narrative, Section 3.A (Overview); Supply Plan Narrative, Section 3.D. (Assessment of Need); Supply Plan Narrative, Section 3.E. (Plan Development); Supply Plan Narrative, Section 3.H (Selection of Preferred Plan)
NAC 704.937	3	In comparing alternative plans containing different resource options, the utility shall calculate the present worth of future requirements for revenue for each alternative plan for the supply of power. A comparison of the present worth of future requirements for revenue for each alternative plan must be presented in the resource plan. As calculated pursuant to this subsection, the present worth of future requirements for revenue for each alternative plan must include, without limitation, a reasonable range of costs associated with emissions of carbon in the 20-year period of the resource plan as private costs to the utility.	Supply Plan Narrative, Section 3.F (Economic Analysis Results); Technical Appendix Item ECON-7 (PWRR)
NAC 704.937	4	The utility shall calculate the present worth of societal costs for each alternative plan for the supply of power. The present worth of societal costs of a particular alternative plan must be determined by adding the environmental costs that are not internalized as private costs to the utility pursuant to subsection 3 to the present worth of future requirements for revenue. In calculating the present worth of societal costs for each alternative plan pursuant to this subsection, the utility shall include as environmental costs the utility's estimate of the level of environmental costs resulting from carbon dioxide emissions for that year and the social cost of carbon.	Supply Plan Narrative, Section 3.G (Environmental Externalities and Net Economic Benefits); Technical Appendix ECON-9 (NERA Report)
NAC 704.937	5	For the purposes of subsection 4 and NAC 704.9215 and 704.9359, the social cost of carbon must be determined by subtracting the costs associated with emissions of carbon internalized as private costs to the utility pursuant to subsection 3 from the net present value of the future global economic costs resulting from the emission of each additional metric ton of carbon dioxide. The net present value of the future global economic costs resulting from the emission of an additional ton of carbon dioxide must be calculated using the best available science and economics such as the analysis set forth in the "Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis" released by the Interagency Working Group on Social Cost of Greenhouse Gases in August 2016. This publication may be obtained, free of charge, at the Internet website https://obamawhitehouse.archives.gov/sites/default/files/omb/inforeg/scc_tsd_final_clean_8_26_16.pdf. The utility shall submit information supporting the method used by the utility to calculate the social cost of carbon.	Supply Plan Narrative, Section 3.G (Environmental Externalities and Net Economic Benefits); Technical Appendix ECON-9 (NERA Report)
NAC 704.937	6	The utility shall consider for each alternative plan the mitigation of risk by means of:	
NAC 704.937	6(a)	Flexibility;	Supply Plan Narrative, Section 3.F (Economic Analysis Results); Supply Plan Narrative, Section 3.H (Selection of Preferred Plan)
NAC 704.937	6(b)	Diversity;	Supply Plan Narrative, Section 3.F (Economic Analysis Results); Supply Plan Narrative, Section 3.H (Selection of Preferred Plan)
NAC 704.937	6(c)	Reduced size of commitments;	Supply Plan Narrative, Section 3.F (Economic Analysis Results); Supply Plan Narrative, Section 3.H (Selection of Preferred Plan)
NAC 704.937	6(d)	Choice of projects that can be completed in short periods;	Supply Plan Narrative, Section 3.F (Economic Analysis Results); Supply Plan Narrative, Section 3.H (Selection of Preferred Plan)

NAC 704.937	6(e)	Displacement of fuel;	Supply Plan Narrative, Section 3.F (Economic Analysis Results); Supply Plan Narrative, Section 3.H (Selection of Preferred Plan)
NAC 704.937	6(f)	Reliability;	Supply Plan Narrative, Section 3.F (Economic Analysis Results); Supply Plan Narrative, Section 3.H (Selection of Preferred Plan)
NAC 704.937	6(g)	Selection of fuel and energy supply portfolios; and	Supply Plan Narrative, Section 3.F (Economic Analysis Results); Supply Plan Narrative, Section 3.H (Selection of Preferred Plan)
NAC 704.937	6(h)	Financial instruments or electricity products.	Supply Plan Narrative, Section 3.F (Economic Analysis Results); Supply Plan Narrative, Section 3.H (Selection of Preferred Plan)
NAC 704.937	7	The alternative plans of the utility must:	
NAC 704.937	7a	Provide adequate reliability;	Supply Plan Narrative, Section 3.F (Economic Analysis Results); Supply Plan Narrative, Section 3.H (Selection of Preferred Plan)
NAC 704.937	7b	Be within regulatory and financial constraints;	Supply Plan Narrative, Section 3.F (Economic Analysis Results); Supply Plan Narrative, Section 3.H (Selection of Preferred Plan); Supply Plan Narrative, Section 4 (Financial Plan)
NAC 704.937	7c	Meet the portfolio standard; and	Supply Plan Narrative, Section 2.D (Renewable Plan); Supply Plan Narrative, Section 3.H (Selection of Preferred Plan)
NAC 704.937	7d	Meet the requirements for environmental protection.	Supply Plan Narrative, Section 2.A (Generation) Supply Plan Narrative, Section 3.H (Selection of Preferred Plan)
NAC 704.937	8	The utility shall identify its preferred plan and fully justify its choice by setting forth the criteria that influenced the utility's choice.	Supply Plan Narrative, Section 3.E (Plan Development); Supply Plan Narrative, Section 3.F (Economic Analysis Results); Supply Plan Narrative, Section 3.H (Selection of Preferred Plan)
NAC 704.9378		**NAC 704.9378 Supply plan: Time-line graphs for proposed resources for supply.** (NRS 703.025, 704.210, 704.741) The supply plan must contain time-line graphs for the utility's proposed resources for supply that include major activities, milestones and points of decision. The following subjects must be included in the time-line graphs for each proposed resource:	
NAC 704.9378	1	Preparation of any required environmental impact statements;	No environmental impact statements in this IRP filing.
NAC 704.9378	2	Applications for significant permits	No permit applications planned for this IRP filing.
NAC 704.9378	3	Commitments of significant expenditures;	No commitment for significant expenditures in this filing
NAC 704.9378	4	Periods for construction; and	No periods of construction in this filing.
NAC 704.9378	5	The commercial operation date.	Renewables Supply Plan Narrative, Section C: Table REN-7
NAC 704.9385		**NAC 704.9385 Supply plan: Contents; tables; transmission plan; information regarding purchase of power; maps; conceptual renewable energy zone transmission plan; list of assets.** (NRS 703.025, 704.210, 704.741)	
NAC 704.9385	1	The supply plan of the utility must develop and document the origins of:	

NAC 704.9385	1(a)	The assumptions, data and projections used by the utility to calculate the costs and benefits of its options.	Technical Appendix Items: LF-1 2024 IRP Load Forecast; FPP-1 Fuel and Purchased Power Price Forecasts; GEN-1 Generating Unit Characteristics Table; GEN-2 Plant Emission Rates; GEN-3 New Generation Unit Performance Data; REN-1 through REN-6; ECON-6 Capital Projects, and ECON-10 Candidate Resources
NAC 704.9385	1(b)	The assessment of current and anticipated electric market conditions by the utility for the region in which the utility operates.	Load Forecast and Market Fundamentals Narrative, Section 2.A
NAC 704.9385	1(c)	The basic economic and financial limitations of the utility.	Supply Plan Volume, Section 4 (Financial Plan)
NAC 704.9385	1(d)	The assumptions used by the utility for developing the environmental costs and the net economic benefits to the State from each of the options of the utility for future supply.	Supply Plan Narrative, Section 3.G (Environmental Externalities and Net Economic Benefits); Technical Appendix Item ECON-9 (NERA Report)
NAC 704.9385	1(e)	The criteria used by the utility for determining the reserve margin.	Supply Plan Narrative, Section 3.C (Key Modeling Assumptions); Technical Appendix Item ECON-12 (2024 Resource Adequacy Study); Technical Appendix Item ECON-13 (Uncertainty Reserves)
NAC 704.9385	1(f)	The assumptions used by the utility for renewable resources.	REN-1 (Proposed Projects Supply Tables), REN-2 Renewable Portfolio Standard Buildout Scenarios
NAC 704.9385	1(g)	The assumptions used by the utility for independent power producers.	Technical Appendix FPP-1
NAC 704.9385	1(h)	The assumptions used by the utility for the reduction in demand and energy requirements associated with customers exiting service from the utility and customers utilizing distributed generation resources.	Technical Appendix LF-1, Sections III, V, and VI
NAC 704.9385	2	Regarding generation, a utility's supply plan must contain a table of all its existing and planned facilities for electric generation that it expects to be operating in each of the 20 years covered by its forecast. Each of the following items of information must be set forth in the table if applicable to a listed facility:	
NAC 704.9385	2(a)	The planned or actual commercial operation date of the facility;	Supply Plan Narrative, Section 2.A (Generation); Supply Plan Narrative, Section 2.D (Renewable Plan)
NAC 704.9385	2(b)	The date of the planned retirement of the facility, including the criteria used to select that date;	Supply Plan Narrative, Section 2.A (Generation); Supply Plan Narrative, Section 2.D (Renewable Plan)
NAC 704.9385	2(c)	The type of facility;	Supply Plan Narrative, Section 2.A (Generation); Supply Plan Narrative, Section 2.D (Renewable Plan)
NAC 704.9385	2(d)	The rated generating capacity and net expected generating capacity of the facility;	Supply Plan Narrative, Section 2.A (Generation); Supply Plan Narrative, Section 2.D (Renewable Plan)
NAC 704.9385	2(e)	The fuel used;	Supply Plan Narrative, Section 2.A (Generation); Supply Plan Narrative, Section 2.D (Renewable Plan)
NAC 704.9385	2(f)	The capacity of the facility for storing fuel; and	Supply Plan Narrative, Section 2.A (Generation); Supply Plan Narrative, Section 2.D (Renewable Plan)
NAC 704.9385	2(g)	The designation of the capacity type of the facility, such as base load, intermediate or peaking.	Supply Plan Narrative, Section 2.A (Generation); Supply Plan Narrative, Section 2.D (Renewable Plan)

NAC 704.9385	3	The supply plan of a utility must include a transmission plan for the 20 years covered by the forecast in the supply plan. The transmission plan must include, without limitation:	
NAC 704.9385	3(a)	A summary of the capabilities of the transmission system, including import, export and the rating of significant transmission paths within the system of the utility, and of the existing and planned transmission system of the utility for each year in the period covered by the resource plan.	Transmission Plan Narrative, Section 2
NAC 704.9385	3(b)	A description of the transmission projects the utility is considering for expanding or upgrading the capabilities of its transmission system, the anticipated timing of those projects and the impact of the projects on the transmission capabilities of the existing and planned transmission system of the utility.	Transmission Plan Narrative, Section 3
NAC 704.9385	3(c)	Identification of the transmission capacity required to serve bundled retail transmission customers, unbundled retail transmission customers and those wholesale transmission customers for whom the utility has an obligation to provide transmission services, for annual and peaking periods throughout the period covered by the resource plan.	Transmission Plan Narrative, Section 2
NAC 704.9385	3(d)	Identification of all existing and proposed transmission service agreements, and their expiration dates, with transmission customers for transmission service on the transmission system of the utility and the impact of these agreements on available capacity for bundled retail transmission customers on the proposed or existing transmission facilities.	Transmission Plan Narrative, Section 2
NAC 704.9385	3(e)	A table identifying all the transmission capacity that the utility has secured for its bundled retail transmission customers on both its transmission system and the transmission systems of other entities.	Transmission Plan Narrative, Section 2
NAC 704.9385	3(f)	A description of the participation of the utility in regional planning organizations and an explanation of the role of those organizations in the transmission planning process of the utility.	Transmission Plan Narrative, Section 8
NAC 704.9385	3(g)	A summary of the impacts of relevant orders of the Federal Energy Regulatory Commission issued since the utility filed its last resource plan.	Transmission Plan Narrative, Section 8
NAC 704.9385	3(h)	(h) A demonstration that the utility has attempted to reduce the impact of line losses upon its future resource requirements.	Transmission Plan Narrative, Section 6
NAC 704.9385	4	Regarding the purchase of power, the supply plan must contain a list showing:	
NAC 704.9385	4(a)	All sources from which the utility has contracted to buy, or has plans or potential opportunities to buy, electric power during the 20 years covered by the supply plan; and	Supply Plan Narrative, Section 2.B (Long-Term Purchase Power Agreements); Section 2.D (Renewable Plan)
NAC 704.9385	4(b)	The amount of electric power that the utility has contracted to buy, or has plans or potential opportunities to buy, from each source and the years for which delivery of the electric power is contracted or planned.	Supply Plan Narrative, Section 2.B (Long-Term Purchase Power Agreements)
NAC 704.9385	5	The utility shall include in its supply plan a map or maps that identify the location of each existing or planned generation or transmission facility, renewable energy system and independent power producer that are projected to be relied upon during the period covered by the action plan.	Supply Plan Narrative, Section 2.A (Generation); Supply Plan Narrative, Section 2.B (Long-Term Purchase Power Agreements); Supply Plan Narrative, Section 2.D (Renewable Plan)
NAC 704.9385	6	The supply plan of a utility must include the list of all assets of the utility required by NRS 704.7338. If a utility owns only part of an asset included on the list, the identity of every other owner and the percentage of the asset owned by each owner must be set forth on the list.	Supply Side Narrative, Section 2.A and Technical Appendix GEN-1
NAC 704.9395		**NAC 704.9395 Resource plan: Information on financial and economic characteristics of planned facilities.** (NRS 703.025, 704.210, 704.741) A utility's resource plan must contain information on the financial and economic characteristics of planned facilities. The information must include:	
NAC 704.9395	1	The estimated costs of construction, including:	
NAC 704.9395	1(a)	Annual flows of expenditures with allowance for money expended during construction; and	Supply Side Narrative, Section 2.A and Technical Appendix GEN-1
NAC 704.9395	1(b)	Annual flows of expenditures without allowance for money expended during construction;	Supply Side Narrative, Section 2.A and Technical Appendix GEN-1
NAC 704.9395	2	The estimated costs of operation, including:	
NAC 704.9395	2(a)	Variable costs per kilowatt-hour, with expenses for fuel and other items indicated separately; and	Technical Appendix Item GEN-1 (Unit Characteristics Table)

NAC 704.9395	2(b)	Fixed costs per kilowatt-hour;	Technical Appendix Item GEN-1 (Unit Characteristics Table)
NAC 704.9395	3	Net environmental costs and net economic benefits to the State;	Supply Plan Narrative, Section 3.G (Environmental Externalities and Net Economic Benefits); Technical Appendix Item ECON-9 (NERA Report)
NAC 704.9395	4	The rates of escalation of cost, including:	
NAC 704.9395	4(a)	Capital costs;	Technical Appendix Item GEN-1 (Unit Characteristics Table)
NAC 704.9395	4(b)	Variable fuel costs;	Technical Appendix Item GEN-1 (Unit Characteristics Table)
NAC 704.9395	4(c)	Nonfuel operating costs;	Technical Appendix Item GEN-1 (Unit Characteristics Table)
NAC 704.9395	4(d)	Environmental costs; and	Technical Appendix Item GEN-1 (Unit Characteristics Table)
NAC 704.9395	4(e)	Fixed operating costs; and	Technical Appendix Item GEN-1 (Unit Characteristics Table)
NAC 704.9395	5	The average cost per kilowatt-hour at projected loads in current dollars for each year of the plan for each existing and planned facility.	Technical Appendix Item ECON-3 (Average Generation Costs for Preferred Plan)
NAC 704.9401		**NAC 704.9401 Financial information and assumptions used to develop financial plan.** (NRS 703.025, 704.210, 704.741)	
NAC 704.9401	1	The assumptions and methodologies for modeling used to develop the utility's financial plan must be described in the resource plan of the utility. The following estimated financial information for the preferred plan must be included in the financial plan:	
NAC 704.9401	1(a)	Present worth of revenue requirements;	Supply Plan Volume, Section 4 (Financial Plan)
NAC 704.9401	1(b)	Nominal revenue requirements by year;	Supply Plan Volume, Section 4 (Financial Plan)
NAC 704.9401	1(c)	Average system rates per kilowatt-hour by year;	Supply Plan Volume, Section 4 (Financial Plan)
NAC 704.9401	1(d)	Total rate base by year;	Supply Plan Volume, Section 4 (Financial Plan)
NAC 704.9401	1(e)	Financial results attributed to the risk management strategy of the utility.	Supply Plan Volume, Section 4 (Financial Plan)
NAC 704.9401	2	The financial assumptions used by the utility to develop its supply plan must be stated in the financial plan. The following items must be stated for each year in the financial plan:	
NAC 704.9401	2(a)	The general rate of inflation;	Supply Plan Volume, Section 4 (Financial Plan)
NAC 704.9401	2(b)	The AFUDC rates used in the supply plan;	Supply Plan Volume, Section 4 (Financial Plan)
NAC 704.9401	2(c)	The cost of capital rates used in the supply plan;	Supply Plan Volume, Section 4 (Financial Plan)
NAC 704.9401	2(d)	The discount rates used in the calculations to determine present worth;	Supply Plan Volume, Section 4 (Financial Plan)
NAC 704.9401	2(e)	The tax rates used in the supply plan;	Supply Plan Volume, Section 4 (Financial Plan)
NAC 704.9401	2(f)	Other assumptions used in the supply plan.	Supply Plan Volume, Section 4 (Financial Plan)
NAC 704.944		**NAC 704.944 Supply plan: Discussion of alternative strategies.** (NRS 703.025, 704.210, 704.741) A utility shall include in its supply plan a comprehensive discussion of the alternative strategies that the utility would pursue if any preferred resource or facility were not available as described in the supply plan.	Section 2.D (Renewable Plan) Supply Plan Volume, Section 3 (Economic Analysis)
NAC 704.945		**NAC 704.945 Resource plan: Inclusion of certain tables and graphs.** (NRS 703.025, 704.210, 704.741)	
NAC 704.945	1	A utility shall include in its resource plan a table of loads and resources for each supply plan analyzed. The table must include the following data for each year of the resource plan:	
NAC 704.945	1(a)	The capacity provided by each supply resource;	Supply Plan Volume, Section 3.I (Loads and Resources Tables): Technical Appendix Item ECON-5

NAC 704.945	1(b)	The total expected capacity of all resources;	Supply Plan Volume, Section 3.I (Loads and Resources Tables): Technical Appendix Item ECON-5
NAC 704.945	1(c)	The forecasted peak demand;	Supply Plan Volume, Section 3.I (Loads and Resources Tables): Technical Appendix Item ECON-5
NAC 704.945	1(d)	The estimated impact of new programs for energy efficiency and conservation;	Supply Plan Volume, Section 3.I (Loads and Resources Tables): Technical Appendix Item ECON-5
NAC 704.945	1(e)	The expected capacity and energy provided by renewable resources, categorized by type;	Supply Plan Volume, Section 3.I (Loads and Resources Tables): Technical Appendix Items ECON-4 and ECON-5
NAC 704.945	1(f)	The required planning reserves;	Supply Plan Volume, Section 3.I (Loads and Resources Tables): Technical Appendix Item ECON-5
NAC 704.945	1(g)	The total capacity required;	Supply Plan Volume, Section 3.I (Loads and Resources Tables): Technical Appendix Item ECON-5
NAC 704.945	1(h)	The excess or deficiency of capacity without additional resources; and	Supply Plan Volume, Section 3.d (Assessment of Need); Section 3.I (Loads and Resources Tables): Technical Appendix Item ECON-5
NAC 704.945	1(i)	The excess or deficiency of capacity with additional planned resources.	Supply Plan Volume, Section 3.I (Loads and Resources Tables): Technical Appendix Item ECON-5
NAC 704.945	2	A graph must be included for the preferred plan of the utility showing, over the 20-year planning period:	
NAC 704.945	2(a)	The total resources requirements;	Supply Plan Volume, Section 3.D (Assessment of Need) Figure EA-4; Section 3.I (Loads and Resources Tables) Figure EA-44
NAC 704.945	2(b)	The total demand without new programs for energy efficiency and conservation;	Supply Plan Volume, Section 3.D Figure EA-4
NAC 704.945	2(c)	The total demand with new programs for energy efficiency and conservation;	Supply Plan Volume, Section 3.I Figure EA-44
NAC 704.945	2(d)	The total capacity with additional planned resources; and	Supply Plan Volume, Section 3.I Figure EA-44
NAC 704.945	2(e)	The total capacity without additional resources.	Supply Plan Volume, Section 3.D Figure EA-4
NAC 704.945	3	A graph must be included for the preferred plan that shows, for each year of the 20-year planning period, the excess or required capacity both with and without the additional planned resources.	Supply Plan Volume, Section 3.D Figure EA-4 and Section 3.I. Figure EA-44
NAC 704.945	4	A table must be included for each supply plan analyzed that shows, for each year of the resource plan:	
NAC 704.945	4(a)	The projected mix of generation by fuel type; and	Supply Plan Volume, Section 3.E Figures EA-29, EA-32, EA-35, and EA-38
NAC 704.945	4(b)	The projected total emissions of carbon dioxide.	Supply Plan Volume, Section 3.E Figure EA-26
NAC 704.945	5	A graph must be included for each supply plan analyzed that shows, for each year of the resource plan, the percentage change in the preferred plan's projected total emissions of carbon dioxide resulting from that supply plan.	Technical Appendix ECON-9
NAC 704.945	6	A graph or table must be provided that shows the allocation of the capacity of the transmission system of the utility between bundled retail transmission customers, unbundled retail transmission customers and wholesale transmission customers.	Transmission Plan Narrative, Section B
NAC 704.9465		**NAC 704.9465 Integrated analysis to establish priorities among options; consideration of results as basis for preferred plan.** (NRS 703.025, 704.210, 704.741)	
NAC 704.9465	1	The utility shall perform an analysis integrating:	
NAC 704.9465	1(a)	Planning based on demand;	Supply Plan Volume, Section 3.E (Plan Development) and Section 3.H (Selection of the Preferred Plan)

NAC 704.9465	1(b)	Planning based on supply;	Supply Plan Volume, Section 3.E (Plan Development) and Section 3.H (Selection of the Preferred Plan)
NAC 704.9465	1(c)	Financial planning; and	Supply Plan Volume, Section 3.E (Plan Development) and Section 3.H (Selection of the Preferred Plan)
NAC 704.9465	1(d)	Planning to meet other applicable regulatory constraints.	Supply Plan Volume, Section 3.E (Plan Development) and Section 3.H (Selection of the Preferred Plan)
NAC 704.9465	2	The primary function of the integrated analysis is to establish priorities among the utility's options for demand and supply so that the utility can demonstrate the minimum costs of providing electric energy to its customers.	Supply Plan Volume, Section 3.H (Selection of the Preferred Plan)
NAC 704.9465	3	The utility shall consider the results of the integrated analysis as a basis for its preferred plan along with the other selection criteria set forth in NAC 704.937.	Supply Plan Volume, Section 3.H (Selection of the Preferred Plan)
NAC 704.9475		**NAC 704.9475 Analysis of sensitivity for major assumptions and estimates used in resource plan.** (NRS 703.025, 704.210, 704.741)	
NAC 704.9475	1	A utility shall conduct an analysis of sensitivity for all major assumptions and estimates used in its resource plan. The analysis must include the:	
NAC 704.9475	1(a)	Forecast of peak demand and energy consumption;	Supply Plan Volume, Section 3.E (Plan Development) and Technical Appendix ECON-5
NAC 704.9475	1(b)	Dates when proposed acquisitions will be in service;	Supply Plan Volume, Section 3.E (Plan Development) and Technical Appendix ECON-5
NAC 704.9475	1(c)	Unit availability;	Technical Appendix Item GEN-1 (Generating Unit Characteristics Table) and Technical Appendix Item ECON-10
NAC 704.9475	1(d)	Costs of power plants;	Supply Plan Volume, Section 2.4.a. (Valmy Simple Cycle Plant) and Technical Appendix ECON-10
NAC 704.9475	1(e)	Prices of fuel;	Technical Appendix Item FPP-1
NAC 704.9475	1(f)	Amounts of purchased power and corresponding costs;	Supply Plan Volume, Section 3.F (Economic Analysis Results)
NAC 704.9475	1(g)	Schedule, impact and costs of programs for energy efficiency and conservation;	DSM Narrative and Technical Appendices; Technical Appendix Item LF-1
NAC 704.9475	1(h)	Capacity of plants in megawatts;	Technical Appendix Item GEN-1 (Unit Characteristics Table)
NAC 704.9475	1(i)	Discount rates;	Supply Plan Volume, Section 4.F (Common Methodologies/ Assumptions)
NAC 704.9475	1(j)	Rate of inflation;	Supply Plan Volume, Section 4.F (Common Methodologies/ Assumptions)
NAC 704.9475	1(k)	Cost of capital;	Supply Plan Volume, Section 4.F (Common Methodologies/ Assumptions)
NAC 704.9475	1(l)	Environmental costs; and	Supply Plan Volume, Section 3.G (Environmental Externalities and Net Economic Benefit); Technical Appendix ECON-9 (NERA Report)
NAC 704.9475	1(m)	Economic benefit.	Supply Plan Volume, Section 3.G (Environmental Externalities and Net Economic Benefit); Technical Appendix ECON-9 (NERA Report)
NAC 704.9475	2	The utility shall state the ranges and consequences of uncertainty for each of the assumptions and describe methods of combining various uncertainties.	Supply Plan Volume, Section 3.F (Economic Analysis Results); Section 3.B (Economic Analysis Methodology), Figure EA-3 Sensitivities Conducted for Economic Analysis
NAC 704.948		**NAC 704.948 Analysis of decisions** (NRS 703.025, 704.210, 704.741)	
NAC 704.948	1	A utility shall analyze its decisions, taking into account its assessment of risk and identifying particular risks with respect to:	Supply Plan Volume, Section 3.H (Selection of the Preferred Plan) and Section 3.F (Economic Analysis Results)

NAC 704.948	1(a)	Costs;	Supply Plan Volume, Section 3.H (Selection of the Preferred Plan) and Section 3.F (Economic Analysis Results)
NAC 704.948	1(b)	Reliability;	Supply Plan Volume, Section 3.H (Selection of the Preferred Plan) and Section 3.F (Economic Analysis Results)
NAC 704.948	1(c)	Finances;	Supply Plan Volume, Section 3.H (Selection of the Preferred Plan); Section 4 (Financial Plan)
NAC 704.948	1(d)	The volatility of the price of purchased power and fuel; and	Supply Plan Volume, Section 3.H (Selection of the Preferred Plan) and Section 3.F (Economic Analysis Results)
NAC 704.948	1(e)	Any other uncertainties the utility has identified.	Supply Plan Volume, Section 3.H (Selection of the Preferred Plan) and Section 3.F (Economic Analysis Results)
NAC 704.948	2	The utility's analysis must address the relationship among the factors used in making the utility's decision, including the relationship between mitigating risk, minimizing cost and volatility, and maximizing reliability.	Supply Plan Volume, Section 3.H (Selection of the Preferred Plan)
NAC 704.9482		**NAC 704.9482 Requirements for energy supply plan, purchased power procurement plan, fuel procurement plan and risk management strategy; consistency with action plan; annual filings.** (NRS 703.025, 704.210, 704.741)	
NAC 704.9482	1	The resource plan of a utility must contain an energy supply plan for the 3 years covered by the action plan of the utility. The resource plan of a utility must be consistent with the action plan of the utility.	Energy Supply Plan Volume
NAC 704.9482	2	An energy supply plan must be developed by a utility using its base forecast and target planning reserve margin.	Energy Supply Plan Volume, Section 2 (Power and Fuel Requirements)
NAC 704.9482	3	As part of its energy supply plan, a utility shall develop a purchased power procurement plan. The purchased power procurement plan of a utility must include, without limitation:	Energy Supply Plan Volume, Section 4 (Power Procurement Plan)
NAC 704.9482	3(a)	The proposed mix of purchased power products by:	Energy Supply Plan Volume, Section 4 (Power Procurement Plan)
NAC 704.9482	3(a)(1)	Type of resource;	Energy Supply Plan Volume, Section 4 (Power Procurement Plan)
NAC 704.9482	3(a)(2)	Delivery profile; and	Energy Supply Plan Volume, Section 4 (Power Procurement Plan)
NAC 704.9482	3(a)(3)	The term that the utility considers appropriate for the expected demand.	Energy Supply Plan Volume, Section 4 (Power Procurement Plan)
NAC 704.9482	3(b)	A description of the criteria used to determine the proposed mix of power products and the material factors influencing the selection of the criteria;	Energy Supply Plan Volume, Section 4 (Power Procurement Plan)
NAC 704.9482	3(c)	The proposed schedule for procuring the purchased power products, including a description of any competitive procurement processes to be undertaken;	Energy Supply Plan Volume, Section 4 (Power Procurement Plan)
NAC 704.9482	3(d)	A regional assessment of the availability of fuel and purchased power resources for the period covered by the energy supply plan;	Energy Supply Plan Volume, Section 3 (Market Fundamentals and Price Forecasts)
NAC 704.9482	3(e)	A projection of remaining capacity and energy requirements for each year of the period covered by the energy supply plan, after accounting for all existing resources and proposed long-term purchased power obligations;	Energy Supply Plan Volume, Section 2 (Power and Fuel Requirements)
NAC 704.9482	3(f)	A description, by type and term, of each existing purchased power contract with deliveries during the period covered by the energy supply plan;	Energy Supply Plan Volume, Section 4 (Power Procurement Plan)
NAC 704.9482	3(g)	A description, by type, delivery profile and term, of the purchased power products expected to be available to the utility during the period covered by the energy supply plan.	Energy Supply Plan Volume, Section 4 (Power Procurement Plan)
NAC 704.9482	4	As part of its energy supply plan, a utility shall develop a fuel procurement plan for each fuel that the utility uses to generate at least 5 percent of its annual energy requirements. The fuel procurement plan must include, without limitation:	Energy Supply Plan Volume, Section 5 (Gas Procurement Plan)
NAC 704.9482	4(a)	For each year of the energy supply plan, a projection of the quantity of each fuel the utility expects to use for each generating unit owned or controlled by the utility;	Energy Supply Plan Volume, Section 2 (Power and Fuel Requirements)

NAC 704.9482	4(b)	A description of each existing fuel contract with deliveries during the period covered by the energy supply plan, including the type of product, the quantity to be delivered, the delivery point and the term of the contract;	Energy Supply Plan Volume, Section 2 (Power and Fuel Requirements) and Section 6 (Coal Supply Plan)
NAC 704.9482	4(c)	A description of the fuel products available to the utility during the period covered by the energy supply plan, including the type of product, the pricing method, the delivery point and the term of the availability of the fuel products;	Energy Supply Plan Volume, Section 3 (Market Fundamentals & Price Forecasts) and Section 6 (Coal Supply Plan)
NAC 704.9482	4(d)	The proposed mix of fuel products;	Energy Supply Plan Volume, Section 5 (Gas Procurement Plan) and Section 6 (Coal Supply Plan)
NAC 704.9482	4(e)	A description of the criteria used to determine the proposed mix of products and the material factors influencing the selection of the criteria;	Energy Supply Plan Volume, Section 5 (Gas Procurement Plan) and Section 6 (Coal Supply Plan)
NAC 704.9482	4(f)	The proposed schedule for procurement of the fuel, including a description of any competitive procurement process to be undertaken.	Energy Supply Plan Volume, Section 5 (Gas Procurement Plan) and Section 6 (Coal Supply Plan)
NAC 704.9482	5	As part of its energy supply plan, a utility shall include a risk management strategy that includes, without limitation:	Energy Supply Plan Volume, Section 7 (Risk Management Strategy)
NAC 704.9482	5(a)	A description of how the risk management strategy was reflected in the determination of the energy supply plan proposed by the utility;	Energy Supply Plan Volume, Section 7 (Risk Management Strategy)
NAC 704.9482	5(b)	A description of the criteria used to select the proposed risk management strategy and identification of the material factors that influenced the selection of the criteria by the utility;	Energy Supply Plan Volume, Section 7 (Risk Management Strategy)
NAC 704.9482	5(c)	A description of each technique for mitigating risk that was considered;	Energy Supply Plan Volume, Section 7 (Risk Management Strategy)
NAC 704.9482	5(d)	The criteria to be used to evaluate the effectiveness of the risk management strategy.	Energy Supply Plan Volume, Section 7 (Risk Management Strategy)
NAC 704.9482	6	A utility shall annually file with the Commission an evaluation of its purchased power procurement plan, its fuel procurement plan, its risk management strategy and, if applicable, the results of any performance-based methodology for the recovery of costs for natural gas for each year included in its deferred energy application filed pursuant to NAC 704.023 to 704.195, inclusive.	See Docket Nos. 24-03003 and 24-03004
NAC 704.9482	7	The energy supply plan of a utility must include a technical appendix that conforms to NAC 704.922.	Energy Supply Plan Volume, Technical Appendix
NAC 704.9484		**NAC 704.9484 Critical facility: Procedure and purpose for designation; financial incentives.** (NRS 703.025, 704.210, 704.741)	
NAC 704.9484	1	The Commission may, upon the request of a utility or an intervening party pursuant to subsection 2 or upon its own motion, make a determination as to whether to designate a facility of the utility as a critical facility. Such a determination may be made in conjunction with an order issued by the Commission pursuant to subsection 1 of NAC 704.9494 or in another proceeding on the matter.	Supply Plan Volume, Section 2.E. (Transmission Plan) and Section 4 (Financial Plan)
NAC 704.9484	2	A utility and any party granted intervener status may request that the Commission designate a facility of the utility as a critical facility for the purpose of:	Supply Plan Volume, Section 2.E. (Transmission Plan) and Section 4 (Financial Plan)
NAC 704.9484	2(a)	Protecting reliability;	Supply Plan Volume, Section 2.E. (Transmission Plan) and Section 4 (Financial Plan)
NAC 704.9484	2(b)	Promoting diversity of supply and demand side sources;	Supply Plan Volume, Section 2.E. (Transmission Plan) and Section 4 (Financial Plan)
NAC 704.9484	2(c)	Developing renewable energy resources;	Supply Plan Volume, Section 2.E. (Transmission Plan) and Section 4 (Financial Plan)
NAC 704.9484	2(d)	Fulfilling specific statutory mandates;	Supply Plan Volume, Section 2.E. (Transmission Plan) and Section 4 (Financial Plan)
NAC 704.9484	2(e)	Promoting retail price stability; or	Supply Plan Volume, Section 2.E. (Transmission Plan) and Section 4 (Financial Plan)
NAC 704.9484	2(f)	Any combination of paragraphs (a) to (e), inclusive.	Supply Plan Volume, Section 2.E. (Transmission Plan) and Section 4 (Financial Plan)

NAC 704.9484	2(g)	Such a request must be accompanied by supporting analysis and documentation.	Supply Plan Volume, Section 2.E. (Transmission Plan) and Section 4 (Financial Plan)
NAC 704.9484	3	If the Commission designates a facility as a critical facility, the utility may request that incentives associated with that facility be included in rates in an application to change general rates filed pursuant to NAC 703.2201 to 703.2481, inclusive. The incentives may include, without limitation:	Supply Plan Volume, Section 2.E. (Transmission Plan) and Section 4 (Financial Plan)
NAC 704.9484	3(a)	Earning an enhanced return on equity on the designated critical facility over the life of the facility;	Supply Plan Volume, Section 2.E. (Transmission Plan) and Section 4 (Financial Plan)
NAC 704.9484	3(b)	The inclusion in the rates of construction work in progress associated with the designated facility; and	Supply Plan Volume, Section 2.E. (Transmission Plan) and Section 4 (Financial Plan)
NAC 704.9484	3(c)	Designating costs incurred to construct the designated critical facility in a regulatory asset account, to be recorded as a subaccount to Account 182.3 (Other Regulatory Assets). The utility may recover the regulatory asset pursuant to subsection 3 of NAC 704.9523.	Supply Plan Volume, Section 2.E. (Transmission Plan) and Section 4 (Financial Plan)
NAC 704.9486		**NAC 704.9486 Performance-based methodology for recovery of costs for natural gas used as fuel for generation: Proposal for establishment; report of results** (NRS 703.025, 704.210, 704.741)	
NAC 704.9486	1	As part of its energy supply plan, a utility may propose the establishment of a performance-based methodology for the recovery of costs for natural gas used as a fuel for generation. Any proposed performance methodology must be based upon objective standards and criteria.	The Companies are not proposing the establishment of a performance-based methodology for the recovery of costs for natural gas used as a fuel for generation.
NAC 704.9486	2	A proposal for the establishment of a performance-based methodology for the recovery of costs for natural gas must include information sufficient to enable the Commission to evaluate the proposal, including, without limitation:	The Companies are not proposing the establishment of a performance-based methodology for the recovery of costs for natural gas used as a fuel for generation.
NAC 704.9486	2(a)	The criteria to be used in measuring the performance of the utility;	The Companies are not proposing the establishment of a performance-based methodology for the recovery of costs for natural gas used as a fuel for generation.
NAC 704.9486	2(b)	The rationale for using the selected criteria;	The Companies are not proposing the establishment of a performance-based methodology for the recovery of costs for natural gas used as a fuel for generation.
NAC 704.9486	2(c)	If appropriate, the proposed sharing allocation between the utility and its consumers;	The Companies are not proposing the establishment of a performance-based methodology for the recovery of costs for natural gas used as a fuel for generation.
NAC 704.9486	2(d)	The duration of the program; and	The Companies are not proposing the establishment of a performance-based methodology for the recovery of costs for natural gas used as a fuel for generation.
NAC 704.9486	2(e)	Supporting documentation.	The Companies are not proposing the establishment of a performance-based methodology for the recovery of costs for natural gas used as a fuel for generation.
NAC 704.9486	3	If the Commission authorizes a performance-based methodology, the utility shall report the results of the methodology approved by the Commission in the deferred energy application filed by the utility pursuant to NAC 704.023 to 704.195, inclusive. At a minimum, the report must cover the period between the adjustment date for the most recent deferred energy application and the adjustment date for the application which includes the report of the results of the approved methodology.	The Companies are not proposing the establishment of a performance-based methodology for the recovery of costs for natural gas used as a fuel for generation.
NAC 704.9486	4	As used in this section, 'adjustment date' has the meaning ascribed to it in NAC 704.024.	The Companies are not proposing the establishment of a performance-based methodology for the recovery of costs for natural gas used as a fuel for generation.
NAC 704.9489		**NAC 704.9489 Requirements for action plan.** (NRS 703.025, 704.210, 704.7339, 704.734, 704.741)	

NAC 704.9489	1	Each resource plan of a utility must include a detailed action plan based on an integrated analysis of the demand side plan and supply plan of the utility. In its action plan, the utility shall specify all its actions that are to take place during the 3 years commencing with the year following the year in which the resource plan is filed. The action plan must contain:	
NAC 704.9489	1(a)	An introductory section that explains how the action plan fits into the longer-term strategic plan of the utility.	Action Plan, Section I (Introduction)
NAC 704.9489	1(b)	A list of actions for which the utility is seeking the approval of the Commission.	Action Plan, Section II (List of Actions)
NAC 704.9489	1(c)	A schedule for the acquisition of data, including planned activities to update and refine the quality of the data used in forecasting.	Action Plan, Section III (Load Forecasting Data Acquisition)
NAC 704.9489	1(d)	A specific timetable for acquisition of options for the supply of electric energy and for programs for energy efficiency and conservation.	Action Plan, Section IV (Timetable and Budget for Programs)
NAC 704.9489	1(e)	If changes in the methodology are being proposed, a description fully justifying the proposed changes, including an analysis of the costs and benefits. Any changes in methodology that are approved by the Commission must be maintained for the period described in the action plan.	DSM Narrative Sections 1 and 3; Technical Appendix LF-1
NAC 704.9489	1(f)	A section describing any plans of the utility to acquire additional modeling instruments.	DSM Narrative Section 3 (DSMore)
NAC 704.9489	1(g)	A section for the utility's program for energy efficiency and conservation, including:	
NAC 704.9489	1(g)(1)	A description of continued planning efforts;	DSM Narrative and Technical Appendices
NAC 704.9489	1(g)(2)	A plan to carry out and continue selected measures for energy efficiency and conservation that have been identified as desirable; and	DSM Narrative and Technical Appendices
NAC 704.9489	1(g)(3)	Any impacts of imputed debt calculations associated with energy efficiency contracts in the preferred plan.	DSM Narrative and Technical Appendices
NAC 704.9489	1(h)	A section for the utility's program for acquisition of resources for the supply of electric energy for the period covered by the action plan, including:	
NAC 704.9489	1(h)(1)	The immediate plans of the utility for construction of facilities or long-term purchases of power;	Renewables Supply Plan Narrative, Section 3: Table REN-7
NAC 704.9489	1(h)(2)	The expected time for construction of facilities and acquisition of long-term purchases of power identified in subparagraph (1);	Technical Appendices REN-3-DLE(b), REN-4-BS3(b), REN-5-LS(b), REN-6-CS2(b)
NAC 704.9489	1(h)(3)	The major milestones of construction; and	Technical Appendices REN-3-DLE(b), REN-4-BS3(b), REN-5-LS(b), REN-6-CS2(b)
NAC 704.9489	1(h)(4)	Any impacts of imputed debt calculations associated with renewable energy contracts or energy efficiency contracts in the preferred plan.	Not Applicable
NAC 704.9489	2	The action plan must contain an energy supply plan and a distributed resources plan, including, without limitation, a plan to accelerate transportation electrification, as required by NRS 704.7867.	Action Plan, Section II (Action Plan Items)
NAC 704.9489	3	The action plan must contain a budget for planned expenditures suitable for comparing planned and achieved expenditures. Expenses must be listed in a format that is consistent with the categories and periods to be presented in subsequent filings. The budget must be organized in the following categories:	Action Plan, Section IV (Timetable and Budget for Programs)
NAC 704.9489	3(a)	Forecasting of loads;	Load Forecast Narrative and Technical Appendix LF-1
NAC 704.9489	3(b)	Energy efficiency and conservation;	DSM Narrative and Technical Appendices
NAC 704.9489	3(c)	Distributed resources;	Action Plan, Section IV (Timetable and Budget for Programs)
NAC 704.9489	3(d)	Transportation electrification;	Action Plan, Section IV (Timetable and Budget for Programs)
NAC 704.9489	3(e)	Plan for supply; and	Action Plan, Section IV (Timetable and Budget for Programs)
NAC 704.9489	3(f)	Financial plan.	Action Plan, Section IV (Timetable and Budget for Programs)
NAC 704.9489	4	The action plan must contain schedules suitable for comparing planned and actual activities and accomplishments. Milestones and points of decision committing major expenditures must be shown.	Action Plan, Section IV (Timetable and Budget for Programs)

NAC 704.9489	5	The action plan must include the surplus asset retirement plan required by NRS 704.734, for each asset that has been classified as surplus by the utility pursuant to NRS 704.7338 or reclassified as surplus by the Commission pursuant to NRS 704.7339.	Supply Side Narrative, Section 2.A.2 (Other Generation Assets)
NAC 704.9492		**NAC 704.9492 Rates for long-term avoided cost: Inclusion of certain information in resource plan; estimation; specification of proposed limits concerning availability.** (NRS 703.025, 704.210, 704.741)	
NAC 704.9492	1	A utility shall file, as part of its resource plan, the methodology for estimating the rates for long-term avoided cost of the utility, including the capacity and energy components. The rates for long-term avoided cost must be based upon the utility's preferred plan and be consistent with 18 C.F.R. § 292.304(a), (b), (c) and (e).	Supply Plan Volume, Section 3.K (Long-Term Avoided Costs)
NAC 704.9492	2	The estimated rate for long-term avoided cost must be established for various sizes of megawatt blocks, except that:	Supply Plan Volume, Section 3.K (Long-Term Avoided Costs)
NAC 704.9492	2(a)	If the utility has a peak demand of at least 1,000 megawatts, the stated blocks must not exceed 100 megawatts; and	Supply Plan Volume, Section 3.K (Long-Term Avoided Costs)
NAC 704.9492	2(b)	If the utility has a peak demand of less than 1,000 megawatts, the stated blocks must not exceed 10 percent of the system peak.	Supply Plan Volume, Section 3.K (Long-Term Avoided Costs)
NAC 704.9492	3	The components for estimated long-term avoided cost capacity and energy rate must be stated on a cents per kilowatt-hour basis for daily and seasonal peak and off-peak periods and in such a manner that rates for various contract periods may be calculated. At a minimum, the utility shall provide estimated rates for long-term avoided cost for a 20-year contract and the long-term avoided cost by year for 5 years commencing in the year following the filing of the resource plan.	Supply Plan Volume, Section 3.K (Long-Term Avoided Costs)
NAC 704.9492	4	In developing the estimated rates for long-term avoided cost, the proposed rates must not be applied to renewable energy or to energy that is subject to the qualified energy recovery process as defined in NRS 704.7809.	Supply Plan Volume, Section 3.K (Long-Term Avoided Costs)
NAC 704.9492	5	The utility shall specify its proposed limits concerning the availability of the rates for long-term avoided cost.	Supply Plan Volume, Section 3.K (Long-Term Avoided Costs)
NAC 704.9492	6	The resource plan of the utility must include the analyses and calculations used to determine the proposed rates.	Supply Plan Volume, Section 3.K (Long-Term Avoided Costs)
NAC 704.9492	7	The resource plan must include a description of the methodology that will be used to derive the rates for long-term avoided costs from the solicitation of proposals performed pursuant to subsection 5 of NAC 704.9496.	Supply Plan Volume, Section 3.K (Long-Term Avoided Costs)
NAC 704.9494		**NAC 704.9494 Approval or modification of action plan; determination that elements of energy supply plan and distributed resources plan are prudent; recovery of costs to carry out approved plans** (NRS 703.025, 704.210, 704.741, 704.751, 704.785)	
NAC 704.9494	1	The Commission will issue an order:	
NAC 704.9494	1(a)	Approving the action plan of the utility as filed;	Not applicable at time of filing.
NAC 704.9494	1(b)	Modifying the action plan of the utility; or	Not applicable at time of filing.
NAC 704.9494	1(c)	If the plan is not approved as filed or modified, specifying those parts of the action plan the Commission considers inadequate.	Not applicable at time of filing.
NAC 704.9494	2	An action plan shall be deemed to be approved by the Commission only as to that portion of the plan accepted as filed or modified with the consent of the utility pursuant to subsection 1 of NRS 704.751.	Not applicable at time of filing.
NAC 704.9494	3	Approval by the Commission of an action plan constitutes a finding that the programs and projects contained in that action plan, other than the energy supply plan and distributed resources plan, are prudent, including, without limitation, construction of facilities, purchased power obligations, programs for energy efficiency and conservation and impacts of imputed debt calculations associated with renewable energy contracts or energy efficiency contracts. If the Commission subsequently determines that any information relied upon when issuing its order approving or modifying the action plan was based upon information that was known or should have been known by the utility to be untrue or false at the time the information was presented, the Commission may revoke, rescind or otherwise modify its approval of the action plan.	Not applicable at time of filing.
NAC 704.9494	4	If, at the time that the Commission approves the action plan of the utility, the Commission determines that the elements of the energy supply plan are prudent, the Commission will specifically include in the approval of the action plan its determination that the elements contained in the energy supply plan are prudent. For the Commission to make a determination that the elements of the energy supply plan are prudent:	

NAC 704.9494	4(a)	The energy supply plan must not contain any feature or mechanism that the Commission finds would impair the restoration of the creditworthiness of the utility or would lead to a deterioration of the creditworthiness of the utility.	Energy Supply Plan Volume, Section 8 (Determination of Prudence)
NAC 704.9494	4(b)	The energy supply plan must optimize the value of the overall supply portfolio for the utility for the benefit of its bundled retail customers.	Energy Supply Plan Volume, Section 8 (Determination of Prudence)
NAC 704.9494	4(c)	The utility must demonstrate that the energy supply plan balances the objectives of minimizing the cost of supply, minimizing retail price volatility and maximizing the reliability of supply over the term of the plan.	Energy Supply Plan Volume, Section 8 (Determination of Prudence)
NAC 704.9494	4(d)	Failure by a utility to demonstrate that its energy supply plan is prudent in accordance with this subsection does not otherwise affect approval of the action plan, including the energy supply plan, and the utility may subsequently seek a determination that the energy supply plan is prudent in the appropriate deferred energy proceeding.	Not applicable
NAC 704.9494	5	If, at the time that the Commission approves the action plan of the utility, the Commission determines that the elements of the distributed resources plan are prudent, the Commission will specifically include in the approval of the action plan its determination that the elements contained in the distributed resources plan are prudent. For the Commission to make a determination that the elements of the distributed resources plan are prudent:	Not applicable
NAC 704.9494	5(a)	The net distribution system load and distributed resource forecasts, hosting capacity analysis, grid needs assessment and non-wires alternative and locational net benefit analyses must have been prudently performed; and	DRP Narrative
NAC 704.9494	5(b)	The selections of new distributed resources set forth in the distributed resources plan must be reasonable.	DRP Narrative
NAC 704.9494	6	A utility may recover all costs that it prudently and reasonably incurs in carrying out an approved action plan in the appropriate separate rate proceeding. A utility may recover all costs it prudently and reasonably incurs in carrying out an approved distributed resources plan in an appropriate separate rate proceeding. A utility may recover all costs that are prudently and reasonably incurred in carrying out the approved energy supply plan, including deviations pursuant to subsection 1 of NAC 704.9504 approved by the Commission in the appropriate deferred energy application filed pursuant to NAC 704.023 to 704.195, inclusive.	Not applicable at time of filing.
NAC 704.9496		**NAC 704.9496 Estimated rates for long-term avoided cost: General requirements; action by Commission; solicitation of proposals;** report. (NRS 703.025, 704.210, 704.741)	
NAC 704.9496	1	In conjunction with the issuance by the Commission of a final order approving or modifying the action plan, the Commission will issue an order addressing the utility's proposed estimated rates for long-term avoided cost, including the methodology and limits to be used by the utility for its filing pursuant to NAC 704.9492. The Commission will consider the factors listed in 18 C.F.R. § 292.304(a), (b), (c) and (e) in its evaluation of the utility's proposed estimated rates for long-term avoided cost.	Not applicable at time of filing.
NAC 704.9496	2	The utility shall file with the Commission the utility's estimated rates for long term avoided cost within 60 days after the Commission issues its order pursuant to subsection 1 specifying the methodology for estimating the rates for long-term avoided cost.	Not applicable at time of filing.
NAC 704.9496	3	The estimated rates for long-term avoided cost filed by the utility with the Commission pursuant to subsection 2 must:	
NAC 704.9496	3(a)	Be consistent with the methodology for estimating the long-term avoided cost approved by the Commission and be based upon the resource plan approved by the Commission;	Not applicable at time of filing.
NAC 704.9496	3(b)	Unless otherwise ordered by the Commission, be consistent with the format set forth in subsections 2 and 3 of NAC 704.9492 and be limited to those rates proposed by the utility pursuant to subsection 5 of NAC 704.9492.	Not applicable at time of filing.
NAC 704.9496	4	If required, the Commission will hold a hearing on the estimated rates for long-term avoided cost within 90 days after the utility files the estimated rates for long-term avoided cost pursuant to subsection 2. If a hearing is held, the Commission will issue an order on the matter within 45 days after the conclusion of the hearing.	Not applicable at time of filing.
NAC 704.9496	5	Within 30 days after the date on which the Commission issues an order pursuant to subsection 4, the utility shall solicit proposals to provide the utility capacity or energy, or both, in a manner that complies with the methodology for estimating long-term avoided cost approved by the Commission.	Not applicable at time of filing.

NAC 704.9496	6	Within 90 days after issuing a solicitation of proposals pursuant to subsection 5, the utility shall file with the Commission a report concerning the results of the solicitation.	Not applicable at time of filing.
NAC 704.9496	7	The utility's rate for long-term avoided cost for each block must be the estimated rate for long-term avoided cost established pursuant to this section or the competitive rate solicited pursuant to subsection 5, whichever is lower.	Not applicable at time of filing.
NAC 704.9512		**NAC 704.9512 Submission to Commission of certain purchased power obligations; disclosure of certain affiliate relationships.** (NRS 703.025, 704.210, 704.741)	
NAC 704.9512	1	The utility shall submit to the Commission a copy of:	
NAC 704.9512	1(a)	Each long-term purchased power obligation; and	Supply Plan Volume, Section 2.B; Summary Volume, Section VI
NAC 704.9512	1(b)	Any other purchased power obligation for which the utility is seeking the approval of the Commission, to which the utility is committed or plans to become committed during the period covered by the action plan.	Supply Plan Volume, Section 2.D
NAC 704.9512	2	For any such contract that is not executed at the time the action plan is filed, the utility shall submit the contract, upon execution, to the Commission for review. The utility shall, for each such contract, disclose the existence of any affiliate relationship between the parties.	Not applicable at time of filing.
NAC 704.9514		**NAC 704.9514 Preapproval of certain fuel and purchased power agreements.** (NRS 703.025, 704.210, 704.741) To the extent the Commission deems appropriate, the Commission may preapprove and deem prudent fuel and purchased power agreements by a utility that are less than 3 years in duration.	Not Applicable
NAC 704.952		**NAC 704.952 Sessions for reviewing plans; procedure for resolving issues during sessions; summary of topics and conclusions; public meeting to provide overview of anticipated filing or amendment of resource plan** (NRS 703.025, 704.210, 704.741, 704.744)	
NAC 704.952	1	A utility may schedule sessions for reviewing plans and providing an opportunity for interested persons to:	
NAC 704.952	1(a)	Learn of progress by the utility in developing plans and amendments to plans;	
NAC 704.952	1(b)	Determine whether key assumptions are being applied in a consistent and acceptable manner;	
NAC 704.952	1(c)	Determine whether key results are reasonable; and	
NAC 704.952	1(d)	Offer suggestions on other matters as appropriate.	
NAC 704.952	2	If the utility, the Bureau of Consumer Protection in the Office of the Attorney General, the staff or any other person participating in the process cannot agree to schedule sessions for reviewing plans, any of those persons may petition the Commission to schedule the sessions.	Not applicable at time of filing.
NAC 704.952	3	The parties involved in the review sessions may establish, at the beginning of the sessions, a procedure to resolve any technical issues that are discussed during the sessions.	Not applicable at time of filing.
NAC 704.952	4	If review sessions are held pursuant to subsection 1, the utility shall prepare a brief summary of the major topics on the agendas and the conclusions reached by the parties during the review sessions. The summary must be provided to the Commission in conjunction with testimony supporting the utility's plan.	Technical Appendix ECON-1; Exhibit Williams-Direct-1
NAC 704.952	5	Not less than 4 months before filing a plan required by NRS 704.741, or within a reasonable period before filing an amendment to such a plan pursuant to NRS 704.751, the utility shall meet with staff, the personnel of the Bureau of Consumer Protection and any other interested persons to provide an overview of the plan or amendment.	Technical Appendix ECON-1
NAC 704.952	6	For each meeting held pursuant to subsection 5, the utility shall prepare a notice of the meeting which must include, without limitation, the date, time and location of the meeting and an explanation of the purpose of the meeting. The utility shall distribute the notice by:	Not applicable at time of filing.
NAC 704.952	6(a)	Posting the notice on the Internet website of the utility;	Not applicable at time of filing.
NAC 704.952	6(b)	Sending the notice via electronic mail to each person on the relevant service list maintained by the Commission; and	Not applicable at time of filing.
NAC 704.952	6(c)	Providing the notice to staff of the Commission for publication on the Internet website of the Commission.	Not applicable at time of filing.

NAC 704.9522		**NAC 704.9522 Measurement and verification protocol for energy efficiency and conservation measures: Duties of utility provider.** (NRS 703.025, 704.210, 704.741)	
NAC 704.9522	1	A utility provider shall propose a measurement and verification protocol for all energy efficiency and conservation measures submitted pursuant to NAC 704.9005 to 704.9525, inclusive.	DSM Narrative Sections 3-6; Technical Appendices DSM-11 to DSM-12
NAC 704.9522	2	The utility provider shall comply with, and shall ensure that all energy efficiency and conservation contracts entered into by the utility provider comply with, the most recent measurement and verification protocol approved by the Commission.	DSM Narrative Technical Appendices DSM-13 to DSM-24
NAC 704.95225		**NAC 704.95225 Recovery of certain amounts based on measurable and verifiable effects of implementation of programs for energy efficiency and conservation.** (NRS 703.025, 704.210, 704.785)	
NAC 704.95225	1	An electric utility may recover an amount based on the measurable and verifiable effects of the implementation by the electric utility of programs for energy efficiency and conservation described in the demand side plan of the electric utility and approved by the Commission pursuant to NAC 704.9494 as part of the action plan of the electric utility. The amount recovered must include:	DSM Narrative Sections 2 and 4-6 (2023 program year)
NAC 704.95225	1(a)	The costs reasonably incurred by the electric utility in implementing and administering the programs for energy efficiency and conservation, which are recovered pursuant to paragraph (a) of subsection 2 of NAC 704.9523; and	DSM Narrative Sections 2 and 4-6 (2023 program year)
NAC 704.95225	1(b)	An amount equal to the costs reasonably incurred by the electric utility in implementing and administering the programs for energy efficiency and conservation multiplied by the electric utility's authorized overall rate of return grossed up for taxes applicable to the utility's equity portion of the authorized rate of return, which is recovered pursuant to paragraph (b) of subsection 2 of NAC 704.9523.	DSM Narrative Sections 2 and 4-6 (2023 program year)
NAC 704.95225	2	The Commission will consider the effect of any recovery pursuant to this section on the rates of the customers of the electric utility.	
NAC 704.9523		**NAC 704.9523 Accounting for and recovery of costs of implementing programs for energy efficiency and conservation.** (NRS 703.025, 704.210, 704.785)	
NAC 704.9523	1	All costs of implementing programs for energy efficiency and conservation calculated pursuant to paragraph (a) of subsection 2 and the amounts calculated pursuant to paragraph (b) of subsection 2 must be accounted for in the books and records of an electric utility separately from costs and amounts attributable to any other activity. All accounts must be maintained in a manner that will allow costs and amounts attributable to specific programs to be readily identified.	DSM Narrative Sections 2 and 4-6 (2023 program year)
NAC 704.9523	2	An electric utility may, pursuant to subsection 3, recover:	
NAC 704.9523	2(a)	All reasonably incurred costs of implementing programs for energy efficiency and conservation that have been described in the demand side plan of the electric utility and approved by the Commission pursuant to NAC 704.9494 as part of the action plan of the electric utility, including, without limitation, the costs for labor, overhead, materials, incentives paid to customers, advertising, marketing, monitoring and evaluation.	DSM Narrative Sections 2 and 4-6 (2023 program year)
NAC 704.9523	2(b)	An amount equal to the costs calculated pursuant to paragraph (a) multiplied by the electric utility's authorized overall rate of return grossed up for taxes applicable to the utility's equity portion of the authorized rate of return.	DSM Narrative Sections 2 and 4-6 (2023 program year)
NAC 704.9523	3	To recover the reasonably incurred costs of implementing programs for energy efficiency and conservation calculated pursuant to paragraph (a) of subsection 2 and the amounts calculated pursuant to paragraph (b) of subsection 2, an electric utility must:	
NAC 704.9523	3(a)	Establish and maintain separate subsidiary records of the subaccounts of FERC Account 182.3 (Other Regulatory Assets) for each program described in the demand side plan of the electric utility and approved by the Commission pursuant to NAC 704.9494 as part of the action plan of the electric utility. These records must clearly delineate all costs calculated pursuant to paragraph (a) of subsection 2 and amounts calculated pursuant to paragraph (b) of subsection 2 and be maintained by program by month by rate effective period.	DSM Narrative Sections 2 and 4-6 (2023 program year)

NAC 704.9523	3(b)	At the time the electric utility files an annual deferred energy accounting adjustment application pursuant to subsection 3 of NRS 704.187, apply to the Commission to establish the following period-specific rates:	Not Applicable
NAC 704.9523	3(b)(1)	A prospective base program cost rate which is determined by allocating in the manner approved by the Commission in the most recent general rate case of the electric utility the total cost of programs for energy efficiency and conservation that are described in the demand side plan approved by the Commission. The prospective base program cost rate for a customer class is an amount equal to the cost allocated to that customer class pursuant to this subparagraph divided by the projected kilowatt hour sales for that class for the relevant period.	Not Applicable
NAC 704.9523	3(b)(2)	A deferred program cost rate to clear the period-specific balance over 12 months. The deferred program cost rate is an amount equal to the period-specific balance in the subaccount of FERC Account No. 182.3 for the cost of programs for energy efficiency and conservation divided by the applicable test period kilowatt hour sales.	Not Applicable
NAC 704.9523	3(c)	At the time the electric utility files an annual deferred energy accounting adjustment application pursuant to subsection 3 of NRS 704.187, file a statement that reports the Nevada jurisdictional earned rate of return for each month of the test period for the electric utility. The Nevada jurisdictional earned rate of return must be calculated for each month of the test period on a 12-month average rate base. The statement must be accompanied by all subsidiary schedules, and any adjustments made thereto, necessary to support the calculations.	Not Applicable
NAC 704.9523	4	Except as otherwise provided in subsection 8, if the Nevada jurisdictional earned rate of return for the last month of the test period reported for an electric utility pursuant to paragraph (c) of subsection 3 exceeds the rate of return last authorized by the Commission to set rates for the electric utility, the electric utility must, at the time the electric utility files the annual deferred energy accounting adjustment application pursuant to subsection 3 of NRS 704.187:	Not Applicable
NAC 704.9523	4(a)	File a statement that reports calculations of:	Not Applicable
NAC 704.9523	4(a)(1)	The amount of revenue which caused the electric utility to exceed the rate of return last authorized by the Commission;	Not Applicable
NAC 704.9523	4(a)(2)	An adjustment to the amount calculated pursuant to paragraph (b) of subsection 2; and	Not Applicable
NAC 704.9523	4(a)(3)	The carrying charges at a monthly rate of 1/12 of the authorized overall rate of return on the adjustment amount calculated pursuant to subparagraph (2).	Not Applicable
NAC 704.9523	4(b)	Establish a rate of credits for adjustments calculated pursuant to subparagraph (2) of paragraph (a) attributable to each class of service and which are identifiable from the information maintained in accordance with paragraph (a) of subsection 3.	Not Applicable
NAC 704.9523	5	Except as otherwise provided in subsection 8, an electric utility must:	
NAC 704.9523	5(a)	Record any adjustment calculated pursuant to subparagraph (2) of paragraph (a) of subsection 4 in a subaccount of FERC Account No. 254.	Not Applicable
NAC 704.9523	5(b)	Transfer any balance which remains in the subaccount of FERC Account No. 254 at the end of the amortization period to the appropriate subaccount of FERC Account No. 182.3 for the current period.	Not Applicable
NAC 704.9523	5(c)	Maintain sufficiently detailed information to identify the amount of the adjustment attributable to each class of service.	Not Applicable
NAC 704.9523	6	Except as otherwise provided in subsection 8, the sum of the adjustment calculated pursuant to subparagraph (2) of paragraph (a) of subsection 4 and any adjustments for carrying charges made to subaccounts of FERC Account No. 182.3 must not exceed the amount of revenue calculated pursuant to subparagraph (1) of paragraph (a) of subsection 4.	Not Applicable
NAC 704.9523	7	An electric utility shall account for period-specific costs incurred to implement a program for energy efficiency and conservation calculated pursuant to paragraph (a) of subsection 2, amounts calculated pursuant to paragraph (b) of subsection 2 and revenues received from the period-specific prospective base program cost rate in the following manner:	
NAC 704.9523	7(a)	On a monthly basis, the electric utility shall record in a subaccount of FERC Account No. 182.3 the program costs incurred, amounts calculated pursuant to paragraph (b) of subsection 2 and the revenues received from the prospective base program cost rate for the program for energy efficiency and conservation.	Not Applicable

NAC 704.9523	7(b)	The electric utility shall apply a carrying charge at the rate of 1/12 of the authorized overall rate of return to the unamortized balance in the subaccounts of FERC Account No. 182.3. If, in any month, the balance in a subaccount of FERC Account No. 182.3 is a debit, an adjustment amount must be calculated in an amount equal to the amount which exceeds the electric utility's last authorized rate of return that was used to set rates for the electric utility or any remainder after the rate of return has been applied to the carrying charge calculation for deferred energy pursuant to NAC 704.150.	Not Applicable
NAC 704.9523	8	If the Commission authorizes a rate adjustment mechanism for an electric utility pursuant to paragraph (b) of subsection 1 of NRS 704.785, the provisions of subsections 4, 5 and 6 do not apply to the electric utility.	Not Applicable
NAC 704.9525		**NAC 704.9525 Severability.** (NRS 703.025, 704.210, 704.741) If any provision of NAC 704.9005 to 704.9525, inclusive, is held invalid, the Commission intends that such invalidity not affect the remaining provisions to the extent that they can be given effect.	
NAC 704.8885		**NAC 704.8885 Long-term portfolio energy credits contracts, long-term renewable energy contracts and energy efficiency contracts: Review by Commission; criteria for approval.** (NRS 703.025, 704.210, 704.7821, 704.7828)	
NAC 704.8885	1	If a utility provider executes a long-term portfolio energy credits contract, long-term renewable energy contract or energy efficiency contract, the utility provider shall submit the contract to the Commission for approval. The contract shall be deemed to be a long-term purchase obligation for the purposes of NAC 704.9005 to 704.9525, inclusive, and the utility provider shall submit the contract to the Commission for approval in accordance with the provisions of those sections.	Technical Appendices REN-3-DLE(a), REN-4-BS3(a), REN-5-LS(a), REN-6-CS2(a)
NAC 704.8885	2	To approve a long-term portfolio energy credits contract, long-term renewable energy contract or energy efficiency contract executed by a utility provider, the Commission must determine that the terms and conditions of the contract are just and reasonable. In making its determination, the Commission will consider, as applicable and without limitation.	
NAC 704.8885	2(a)	The reasonableness of the price for the electricity based on the factors set forth in NAC 704.8887;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8885	2(b)	The term of the contract;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8885	2(c)	The location of each portfolio energy system or efficiency measure that is subject to the contract;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8885	2(d)	The use of natural resources by each renewable energy system that is subject to the contract;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8885	2(e)	The firmness of the electricity to be delivered and the delivery schedule;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8885	2(f)	The delivery point for the electricity;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8885	2(g)	The characteristics of similar renewable energy systems;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8885	2(h)	The requirements for ancillary services;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8885	2(i)	The unit contingent provisions;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8885	2(j)	The system peak capacity requirements of the utility provider;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8885	2(k)	The requirements for scheduling;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)

NAC 704.8885	2(l)	Conditions and limitations on the transmission system;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c),TRAN-1, TRAN-2, TRAN-3 and Transmission Plan, Section B.
NAC 704.8885	2(m)	Project insurance;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8885	2(n)	The costs for procuring replacement power in the event of nondelivery;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8885	2(o)	Information verifying that each renewable energy system which is subject to the contract transmits or distributes or will transmit or distribute the electricity that it generates from renewable energy in accordance with the requirements of NRS 704.7815;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8885	2(p)	For each owner and for each operator of a renewable energy system that is subject to the contract, the total number of renewable energy systems that each such owner and each such operator is or has been associated with as an owner or operator, including, without limitation, all renewable energy systems that are actively being constructed by or have been constructed by the owner or operator;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8885	2(q)	For each renewable energy system that is subject to the contract, the points of interconnection with the electric system of the utility;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8885	2(r)	The interconnection priority which has been established for the available transmission capacity of the utility provider for all proposed renewable energy systems that will interconnect and begin commercial operation within the 3-year period immediately following the date on which the contract is submitted for approval;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8885	2(s)	Any requests for transmission service that have been filed with the utility provider;	Transmission Plan Narrative, Section 2, FIGURE TP-11.1 and FIGURE TP-11.2
NAC 704.8885	2(t)	For each renewable energy system that is subject to the contract, any evidence that an environmental assessment, an environmental impact statement or an environmental impact report is being completed or has been completed with regard to the renewable energy system, or any evidence that a contract has been executed with an environmental contractor who will prepare such an assessment, statement or report within the 3-year period immediately preceding the date on which the renewable energy system is projected to begin commercial operation;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8885	2(u)	Whether any required permits have been acquired from or any applications for such permits have been filed with the appropriate governing agencies within the 3-year period immediately preceding the date on which the renewable energy system is projected to begin commercial operation;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8885	2(v)	Whether any applications for developmental rights have been filed with the appropriate federal agencies, including, without limitation, the United States Bureau of Land Management, where the granting of such developmental rights is not contingent upon a competitive bidding process;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8885	2(w)	For each renewable energy system that is subject to the contract, any evidence that establishes rights of ownership, possession or use concerning land or natural resources, including, without limitation, deeds, land patents, leases, contracts, licenses or permits concerning land, geothermal drilling rights or other rights to natural resources; and	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8885	2(x)	Whether the utility provider has any economical dispatch rights.	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8887		**NAC 704.8887 Long-term portfolio energy credits contracts, long-term renewable energy contracts and energy efficiency contracts: Determination of whether price for electricity is reasonable**. (NRS 703.025, 704.210, 704.7821, 704.7828)	
NAC 704.8887	1	For the purposes of this section, each utility provider shall calculate the price for electricity acquired or saved pursuant to a long-term portfolio energy credits contract, long-term renewable energy contract or energy efficiency contract by calculating the levelized market price for the electricity based on:	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)

NAC 704.8887	1(a)	The rates for electricity and capacity set forth in the contract;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8887	1(b)	Any escalators or inflation indices set forth in the contract;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8887	1(c)	Any delivery projections for electricity and capacity set forth in the contract; and	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8887	1(d)	Any other terms and conditions set forth in the contract that would affect the price paid for electricity acquired or saved pursuant to the contract.	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8887	2	All data that the utility provider uses to make its calculation must be based on the most current projections available when the contract is executed. After the utility provider calculates the price pursuant to subsection 1, the Commission will determine whether the price is reasonable. In making its determination, the Commission will consider, without limitation:	
NAC 704.8887	2(a)	Whether the contract comports with the utility provider's most recently approved plan to increase its supply of or decrease the demand for electricity that is submitted to the Commission pursuant to NAC 704.9005 to 704.9525, inclusive;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8887	2(b)	The reasonableness of any price indexing provision set forth in the contract;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8887	2(c)	As compared to competing facilities or energy systems that use one or more fossil fuels as their primary source of energy to generate electricity, whether the renewable energy systems that are subject to the contract will reduce environmental costs in this State, including, without limitation:	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8887	2(c)(1)	Air emissions;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8887	2(c)(2)	Water consumption;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8887	2(c)(3)	Waste disposal and other land uses; and	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8887	2(c)(4)	Impacts on wildlife;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8887	2(d)	The net economic impact and all environmental benefits and environmental costs to this State in accordance with NAC 704.9005 to 704.9525, inclusive:	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8887	2(e)	Any economic development benefits that might inure to any sector of the economy of this State;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8887	2(f)	The diversity of energy sources being used to generate the electricity that is consumed in this State;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8887	2(g)	The diversity of energy suppliers generating or selling electricity in this State;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8887	2(h)	The value of any price hedging or energy price stability associated with the contract;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8887	2(i)	The date on which each renewable energy system that is subject to the contract is projected to begin commercial operation;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8887	2(j)	Whether the utility provider has any flexibility concerning the quantity of electricity that the utility provider must acquire or save pursuant to the contract;	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)

NAC 704.8887	2(k)	Whether the contract will result in any benefits to the transmission system of the utility provider; and	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8887	2(l)	Whether the electricity acquired or saved pursuant to the contract is priced at or below the utility provider's long-term avoided cost rate.	Technical Appendices REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
NAC 704.8887	3	If a utility provider will be using a long-term portfolio energy credits contract, long-term renewable energy contract or energy efficiency contract to comply with the solar energy requirements of its portfolio standard, the price for electricity acquired pursuant to that contract will be evaluated separately from the price for electricity acquired or saved pursuant to other long-term portfolio energy credits contracts, long-term renewable energy contracts or energy efficiency contracts that will not be used to comply with the solar energy requirements of the portfolio standard.	

IRP List of Applicable Statutes

	Code	Sub-Section	Description	2024 IRP Location
1	**NRS 704.741**		**NRS 704.741 Plan to increase supply or decrease demands: Triennial submission required; joint plans by certain affiliated utilities; contents prescribed by regulation; requirements.**	
2	NRS 704.741	1	A utility which supplies electricity in this State shall, on or before June 1 of every third year, or more often if necessary, in the manner specified by the Commission, submit a plan to increase its supply of electricity or decrease the demands made on its system by its customers to the Commission. Two or more utilities that are affiliated through common ownership and that have an interconnected system for the transmission of electricity shall submit a joint plan.	The 2024 Joint IRP presents a plan to increase the Companies' supply of electricity and decrease the demands made on the Companies' system.
3	NRS 704.741	2	The Commission shall, by regulation:	
4	NRS 704.741	2(a)	Prescribe the contents of such a plan, including, but not limited to, the methods or formulas which are used by the utility or utilities to:	
5	NRS 704.741	2(a)(1)	Forecast the future demands, except that a forecast of the future retail electric demands of the utility or utilities must not include the amount of energy and capacity proposed pursuant to subsection *6* as annual limits on the total amount of energy and capacity that eligible customers may be authorized to purchase from providers of new electric resources through transactions approved by the Commission pursuant to an application submitted pursuant to NRS 704B.310 on or after May 16, 2019; and	Technical Appendix LF-1, Section V
6	NRS 704.741	2(a)(2)	Determine the best combination of sources of supply to meet the demands or the best method to reduce them;	Supply Plan Volume, Section 3.H. (Selection of the Preferred Plan), DSM Narrative Sections 1 - 6, and DRP Plan
7	NRS 704.741	2(b)	Designate renewable energy zones and revise the designated renewable energy zones as the Commission deems necessary, and	
8	NRS 704.741	2(c)	Establish requirements governing the manner in which and circumstances under which an amendment may be filed with the Commission to modify an approved plan.	Not applicable at time of this filing
9	NRS 704.741	3	The Commission shall require the utility or utilities to include in the plan:	
10	NRS 704.741	3(a)	An energy efficiency program for residential customers which reduces the consumption of electricity or any fossil fuel and which includes, without limitation, the use of new solar thermal energy sources.	DSM Narrative Section 3; Gas C&EE Narrative
11	NRS 704.741	3(b)	A proposal for the expenditure of not less than 10 percent of the total expenditures related to energy efficiency and conservation programs on energy efficiency measures for customers of the electric utility in low-income households and residential customers and public schools in historically underserved communities, through both targeted programs and programs directed at residential customers and public schools in general.	DSM Narrative Sections 3 - 6; Technical Appendix Item DSM-18
12	NRS 704.741	3(c)	A comparison of a diverse set of scenarios of the best combination of sources of supply to meet the demands or the best methods to reduce the demands, which must include:	Supply Plan Narrative, Section 3.E. (Plan Development)
13	NRS 704.741	3(c)(1)	At least one scenario of low carbon dioxide emissions that:	
14	NRS 704.741	3(c)(1)(I)	Uses sources of supply that result in, by 2050, an amount of energy production from zero carbon dioxide emission resources that equals the forecasted demand for electricity by customers of the utility;	Supply Plan Volume, Section 3.E (Plan Development)
15	NRS 704.741	3(c)(1)(II)	Includes the deployment of distributed generation; and	Supply Plan Volume, Section 3.E (Plan Development)
16	NRS 704.741	3(c)(1)(III)	If the plan is submitted on or before June 1, 2027, uses sources of supply that result in, by the year 2030, an 80 percent reduction in carbon dioxide emissions from the generation of electricity to meet the demands of customers of the utility as compared to the amount of such emissions in the year 2005.	Supply Plan Volume, Section 3.E (Plan Development)

17	NRS 704.741	3(c)(2)	At least one scenario that provides for the construction or acquisition of energy resources through contract or ownership to be placed into service to close an open position utilizing dedicated energy resources in this State and dedicated energy resources delivered through firm transmission. A significant share of the renewable energy facilities and energy storage systems included in the scenario must be owned by the utility. A requirement to include a particular scenario in the plan pursuant to this paragraph, or the compliance of a utility with such a requirement, shall not be construed as indicating a preference by the Commission or the utility for a particular scenario.	Supply Plan Volume, Section 3.E (Plan Development)
18	NRS 704.741	3(d)	An analysis of the effects of the requirements of NRS 704.766 to 704.776, inclusive, on the reliability of the distribution system of the utility or utilities and the costs to the utility or utilities to provide electric service to all customers. The analysis must include an evaluation of the costs and benefits of addressing issues or reliability though investment in the distribution system.	DRP Narrative, Section 2.F
19	NRS 704.741	3(e)	A list of the utility's or utilities' assets described in NRS 704.7338.	Supply Plan Volume, Section 2A (Generation)
20	NRS 704.741	3(f)	A surplus asset retirement plan as required by NRS 704.734.	Supply Plan Volume, Section 2A (Generation)
21	NRS 704.741	4	For each scenario considered pursuant to subsection 3, the plan must include, without limitation:	
22	NRS 704.741	4(a)	For each energy resource proposed:	
23	NRS 704.741	4(a)(1)	A description of each energy resource to be constructed, acquired or contracted for by the utility, including, without limitation, the location of the energy resource, the technology to be used by the energy resource to generate electricity, the anticipated capacity of the energy resource and the anticipated date by which the energy resource will be placed into service;	Renewables Supply Plan Narrative, Section 3, Table REN-7
24	NRS 704.741	4(a)(2)	The cost of constructing or acquiring, operating and maintaining the energy resource or, if the energy resource is contracted for by the utility, the price of the energy to be supplied by the energy resource;	Renewables Supply Plan Narrative, Section 3; Technical Appendix Items REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
25	NRS 704.741	4(a)(3)	Whether the energy resource will be owned by the utility or utilized by the utility pursuant to a contract with a third party; and	Renewables Supply Plan Narrative, Section 3
26	NRS 704.741	4(a)(4)	Any other information required by the Commission to evaluate the prudence of the scenario.	Renewables Supply Plan Narrative, Section 3, Table REN-7; Technical Appendix REN-3-DLE(c), REN-4-BS3(c), REN-5-LS(c), REN-6-CS2(c)
27	NRS 704.741	4(b)	An evaluation of the impact that the implementation of the scenario will have on:	
28	NRS 704.741	4(b)(1)	The ability of the utility to decrease its reliance on market purchases to meet the utility's open energy load requirements, including, without limitation, any appropriate reserves, and the forecast of energy needs over the next 10 years;	Supply Plan Volume, Section 3.E. (Plan Development) and Load Forecast Volume
29	NRS 704.741	4(b)(2)	The ability of the utility to reliably integrate into its supply portfolio larger amounts of electricity from variable energy resources, including, without limitation, solar, geothermal, hydropower and wind energy resources;	Supply Plan Volume, Section 3.E (Plan Development)
30	NRS 704.741	4(b)(3)	The ability of the utility to access energy markets or geographic locations that have excess capacity to import into this State through firm transmission to ensure additional reliability in times of increased energy needs;	Supply Plan Volume, Section 3.E. (Plan Development)
31	NRS 704.741	4(b)(4)	The ability of the utility to increase access to carbon-free energy, support compliance with the renewable portfolio standard and advance the goals for the reduction of greenhouse gas emissions set forth in NRS 445B.380 and 704.7820 through a balanced portfolio of energy supply and demand-side resources;	Supply Plan Volume, Section 3.E. (Plan Development) and Section 2.D Renewable Plan
32	NRS 704.741	4(b)(5)	The ability of the utility to demonstrate to a regional entity that the utility has adequate resources to meet the forecast for energy needs over the next 10 years;	Supply Plan Volume, Section 3.H. (Selection of the Preferred Plan) and Section 5 (Day Ahead Markets and Regional Transmission Organization)
33	NRS 704.741	4(b)(6)	The ability of the utility to advance cost-effective demand-side management;	Supply Plan Volume, Section 3.E. (Plan Development)

34	NRS 704.741	4(b)(7)	The rates charged to the customers of the utility, provided that, in implementing the plan, the utility must endeavor to mitigate costs for the benefit of customers to the extent possible by utilizing federal funding and tax credits available to utilities or third parties for the development of electric resources; and	Supply Plan Volume, Section 4 (Financial Plan)
35	NRS 704.741	4(b)(8)	The benefits from high-quality jobs, job training and apprenticeships provided by the projects included in the plan, whether constructed or operated by the utility or a third-party developer.	Supply Plan Volume, Section 3.E. (Plan Development), Section 3.G. (Environmental Externalities and Net Economic Benefits) and Technical Appendix Item ECON-9 (NERA Report)
36	NRS 704.741	5	The Commission shall require the utility or utilities to include in the plan a distributed resources plan. The distributed resources plan must:	DRP Narrative
37	NRS 704.741	5(a)	Evaluate the locational benefits and costs of distributed resources. This evaluation must be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits and any other savings the distributed resources provide to the electricity grid for this State or costs to customers of the electric utility or utilities.	DRP Narrative, Section 3A
38	NRS 704.741	5(b)	Propose or identify standard tariffs, contracts or other mechanisms for the deployment of cost-effective distributed resources that satisfy the objectives for distribution planning.	DRP Narrative
39	NRS 704.741	5(c)	Propose cost-effective methods of effectively coordinating existing programs approved by the Commission, incentives and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.	DRP Narrative, Section 5.B
40	NRS 704.741	5(d)	Identify any additional spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding a net benefit to the customers of the electric utility or utilities.	DRP Narrative, Section 7
41	NRS 704.741	5(e)	Identify barriers to the deployment of distributed resources, including, without limitation, safety standards related to technology or operation of the distribution system in a manner that ensures reliable service.	DRP Narrative, Section 4
42	NRS 704.741	5(f)	Include a transportation electrification plan as required by NRS 704.7867.	DRP Narrative, Section 10
43	NRS 704.741	6	The Commission shall require the utility or utilities to include in the plan a proposal for annual limits on the total amount of energy and capacity that eligible customers may be authorized to purchase from providers of new electric resources through transactions approved by the Commission pursuant to an application submitted pursuant to NRS 704B.310 on or after May 16, 2019. In developing the proposal and the forecasts in the plan, the utility or utilities must use a sensitivity analysis that, at a minimum, addresses load growth, import capacity, system constraints and the effect of eligible customers purchasing less energy and capacity than authorized by the proposed annual limit. The proposal in the plan must include, without limitation:	Technical Appendix LF-1, Section V
44	NRS 704.741	6(a)	A forecast of the load growth of the utility or utilities;	Technical Appendix LF-1, Section IV
45	NRS 704.741	6(b)	The number of eligible customers that are currently being served by or anticipated to be served by the utility or utilities;	Technical Appendix LF-1, Sections III and IV
46	NRS 704.741	6(c)	Information concerning the infrastructure of the utility or utilities that is available to accommodate market-based new electric resources;	Technical Appendix LF-1, Section VI
47	NRS 704.741	6(d)	Proposals to ensure the stability of rates and the availability and reliability of electric service; and	Technical Appendix LF-1, Section VI
48	NRS 704.741	6(e)	For each year of the plan, impact fees applicable to each megawatt or each megawatt hour to account for costs reflected in the base tariff general rate and base tariff energy rate paid by end-use customers of the electric utility.	Technical Appendix LF-1, Section VI
49	NRS 704.741	7	The annual limits proposed pursuant to subsection 6 shall not apply to energy and capacity sales to an eligible customer if the eligible customer:	Technical Appendix LF-1, Sections V and VI
50	NRS 704.741	7(a)	Was not an end-use customer of the electric utility at any time before June 12, 2019; and	Technical Appendix LF-1, Sections V and VI
51	NRS 704.741	7(b)	Would have a peak load of 10 megawatts or more in the service territory of an electric utility within 2 years of initially taking electric service.	Technical Appendix LF-1, Sections V and VI

EXHIBIT C

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

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

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

> **Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the 2024 Joint Integrated Resource Plan.**

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

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

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

> **Nevada Power Company and Sierra Pacific Power Company are seeking approval of the 2024 Joint Integrated Resource Plan. The 2024 Joint IRP presents analysis of resource options (energy efficiency and conservation, distributed energy resources, renewable generation, conventional generation and transmission) available to the Companies to meet their bundled retail or native load over 20 years (as prescribed by regulation) as well as the 26-year period ending in 2050 to demonstrate planning towards the state's 2050 clean energy goal. Embodied in this 2024 Joint IRP is an updated load forecast, a market fundamentals forecast including fuel and purchase power pricing, a supply plan that includes a generation section, transmission plan, renewables section, economic analysis and finally a financial plan. Embedded in the 2024 Joint IRP is a Joint ESP, as required by Nevada Administrative Code ("NAC") § 704.9482. The Joint ESP and its associated technical appendices are located in stand-alone volumes filed as part of the 2024 Joint IRP. The 2024 Joint IRP also includes a demand side management ("DSM") plan and a distribution resource plan ("DRP"). The 2024 Joint IRP addresses renewable portfolio standard ("RPS") and capacity concerns created by incremental cancellations of previously approved projects and continues to advance resource sufficiency for the Companies as required for participation in WRAP, a future day-ahead market, and/or a future regional transmission organization ("RTO"). The 2024 Joint IRP also outlines the Companies' intent to the join the California**

Independent System Operator ("CAISO") Expanded Day-Ahead Market ("EDAM").

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

No. A consumer session is not required by NRS § 704.069.

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

Not Applicable.

[1] NRS 704.069 states in pertinent part:

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

EXHIBIT D

Schedule No. ESB-V2G
Electric School Bus Vehicle-to-Grid Trial

APPLICABLE

This tariff provides for a pilot program to demonstrate the implementation of load management and discharge to grid capabilities of a fleet of Utility incentivized public school buses. Any public school district enrolled in the Utility's Electric School Bus Vehicle-to-Grid (T)
Trial Program, or who previously received a utility incentive towards the cost of electric school (T)
buses is eligible for this tariff. (D)

SUNSET PROVISION

The pilot will begin on January 1, 2022 and complete on December 31, 2024.

If at the end of the three-year study period, the Commission determines that this tariff should not be adopted on a permanent basis, the Customers taking service under this pilot program shall be allowed to remain on the tariff for the life of their interconnected equipment not to exceed the useful life of the electric school bus, currently estimated at 12 years.

TERRITORY

Entire Nevada Service Area, as specified.

DESCRIPTION OF SERVICE

To fleet operators of electric school buses with more installed vehicle batteries that are capable of supplying energy to the grid through discharging the batteries. Customers will pay the rates of their Otherwise Applicable Schedule ("OAS") for energy delivered to the premise, but will be eligible for a monetary credit for any energy that is discharged from the batteries back to the grid.

Interconnection

Customers that participate in the ESB-VG2 Trial agree to charging of SB-EVG participating buses from the Utility grid and may not charge Utility incentivized buses from on-site generation.

Available Capacity Election

Customers that participate in the ESB-VG2 Trial will provide the utility with the installed/minimum capacity of vehicle to grid resources. In the event that the available capacity increases or decreases by greater than 15%, the Customer will notify the Utility of the change in dispatchable resources.

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EXHIBIT E

Schedule No. ESB-V2G
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RYAN ATKINS

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05___

Prepared Direct Testimony of

Ryan Atkins

I. INTRODUCTION

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

A. My name is Ryan Atkins. My current position is Vice President, Resource Optimization and Resource Planning, for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company ("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 the Companies.

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

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

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

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

A. My current responsibilities involve the oversight of the Resource Optimization and Resource Planning teams. These teams are responsible for a number of activities including, but not limited to, development of the Companies' Integrated Resource Plans, development of the Companies' Energy Supply Plans, development of the Companies' Gas Information Reports, all power and natural gas trading activities, coal procurement, participation in the Western Energy Imbalance Market, and wholesale market design efforts.

4. Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?

A. Yes. I have previously testified before the Commission in deferred energy proceedings, energy supply plan filings, and integrated resource plan filings. Most recently, I filed testimony in the Companies' Fifth Amendment to the 2021 Joint Integrated Resource Plan and the Companies 2024 Deferred Energy filings.

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

A. The purpose of my testimony is to provide support for the overall policy of the Companies' 2024 Joint Integrated Resource Plan ("2024 Joint IRP"). In addition to the overall policy, I also provide support surrounding regional market efforts being undertaken by the Companies, such as participation in the Western Resource Adequacy Program ("WRAP") and the development of a future day-ahead wholesale market. Finally, I also provide support related to continuing resource adequacy concerns in the Western United States.

II. WITNESSES

6. Q. PLEASE DESCRIBE THE WITNESSES SPONSORING THE 2024 JOINT IRP.

A. The sponsors of each of the substantive portions of the 2024 Joint IRP are described below:

Timothy Pollard, Director of Load Forecasting, Research, and Analytics, supports the load forecast used in the filing;

Zeljko Vukanovic, Market Fundamentals Lead, sponsors the Market Fundamentals and Fuel and Purchased Power Price Forecasts;

Vincent Vitiello, Gas Supply Planning Lead, sponsors the gas transportation strategies;

Patricia Rodriguez, Director, Energy Services Optimization, sponsors the Demand Side Plan;

Adam Grant, Director of Integrated Energy Services Operations, sponsors the proposed Transportation Electrification Plan ("TEP");

Christopher Belcher, Integrated Energy Services Policy and Compliance Manager, supports portions of the Demand Side Plan, including aspects of the Demand Side Plan rate impacts;

Lark Lee, Senior Director at Tetra Tech, sponsors the Net-to-Gross ("NTG") study conducted by Tetra Tech on behalf of the Companies for the Demand Side Plan;

Robert Oliver, Principal at ADM Associates, Inc., sponsors the Measurement and Verification ("M&V") reports presented as part of the Demand Side Plan;

Dr. Sanem Sergici, Principal at The Brattle Group, sponsors the Demand Side Plan rate impact analyses pertaining to the enhanced Demand Side Plan spending;

Snuller Price, Senior Partner at Energy and Environmental Economics, supports the Distributed Energy Resources ("DER") evaluation framework and NV Energy's market potential study;

Tom Hines, Principal and Co-founder of Tierra Resource Consultants LLC, also supports the DSM market potential study as well as development of Demand Side Plan portfolios;

Dr. Kenneth Skinner, Vice President of Integral Analytics Inc., supports the financial models in the Demand Side Plan;

Marie Steele, Vice President, Integrated Energy Services, sponsors the Distributed Resources Plan as a policy witness;

Joseph Sinobio, Director of Integrated Grid Planning, sponsors the Distributed Resources Plan as the key technical expert;

Michael Brown, Integrated Energy Services Director, sponsors sections 7.A, 7.B, 8.A.2, and 8.B of the Distributed Resources Plan;

Tyler Meroth, Transmission Planning Engineer, sponsors Section 3.B of the Distributed Resources Plan, Distributed Resources Plan Analyses: Transmission Planning;

Misha Pascal, Regulatory Analysis Lead, supports the Companies' proposal of a Rule 9 allowance mechanism for the facilities required for electric vehicle charging for commercial customers;

Mathew Johns, Vice President, Environmental Services and Land Management, supports the environmental regulatory discussion in the Generation section of the Supply Plan;

John Lescenski, Manager, Plant Engineering and Technical Services, sponsors the Generation section of the Supply Plan including the proposed Valmy combustion turbine project;

Charles Pottey, Director of Transmission Planning, sponsors the Transmission Plan section of the Supply Plan and supports the Companies' requests to construct transmission system network upgrades and the continued need for the Greenlink projects;

Layne Maxfield, Manager, Transmission System Planning, supports the Transmission Plan and the Companies' requests to construct transmission system network upgrades for large customer additions;

Shahzad Lateef, Senior Project Director, supports the updated cost forecast for the Greenlink transmission projects;

John Tsoukalis, Principal at The Brattle Group, supports the economic benefits of the Greenlink transmission projects and addresses the projects' updated cost forecast;

Kiley Moore, Director, Transmission Policy and Business Services, supports the federal regulatory requirements related to the Greenlink transmission projects;

Josh Langdon, Vice President of Transmission, sponsors an updated cost forecast for the Greenlink transmission projects and introduces other witnesses addressing the projects;

Eric Schwarzrock, Vice President, Customer Solutions and Projects, supports the Companies' process working with customers to connect large loads to the transmission and distribution system;

Jimmy Daghlian, Vice President of Renewables, sponsors the Companies' Renewables section of the Supply Plan;

Sean Spitzer, Senior Project Manager, Renewable Energy, sponsors the Companies' renewable energy projects to support the Renewables Section of the Supply Plan;

Mark Warden, Director of Development, Renewable Energy and Origination, describes named placeholders and provides status updates on the Companies' renewable initiatives;

Kimberly Williams, Director of Resource Planning and Analysis, sponsors the economic analysis used in the evaluation of the Supply Plan and other scenarios and describes the No Greenlink scenario and incorporation of the Distributed Resources Plan in the integrated planning process;

Nick Schlag, Partner at Energy and Environmental Economics ("E3"), supports the update of the planning reserve margin and effective load carrying capability values, development of updated uncertainty reserves, resource adequacy planning related to the Companies' open capacity position, and development of the Sierra subsystem resource adequacy analysis in support of the Greenlink projects;

Dr. David Harrison, Economist and Affiliated Consultant at NERA Economic Consulting, supports the environmental cost and economic impacts analyses;

Mike Behrens, Vice President and Chief Financial Officer, sponsors the Financial Plan and the Companies' ability to finance the Preferred and Alternate Plans;

Christopher Sarda, Financial Planning & Analysis Capital Services Director, sponsors the financial forecast modeling and analysis used to support the Financial Plan as well as the alternative plans rate impact analyses; and

Janet Wells, Vice President, Regulatory, supports Energy Supply Agreements ("ESA") used to support large customers' renewable goals.

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

III. RESOURCE PLANNING PROCESS

7. Q. PLEASE DESCRIBE THE PREPARATION OF THE 2024 JOINT IRP

A. The 2024 Joint IRP is required by Nevada state law under Nevada Revised Statute ("NRS") 704.741. NV Energy is required to file a joint IRP for Nevada Power and Sierra by June 1 every three years. The 2024 Joint IRP presents analysis of resource options (energy efficiency and conservation, distributed energy resources, renewable generation, conventional generation and transmission) available to the Companies to meet their bundled retail or native load over 20 years (as prescribed by regulation) as well as the 26-year period ending in 2050 to demonstrate planning towards the state's 2050 clean energy goal.

To aid in understanding the economic analysis performed for this 2024 Joint IRP, an overall flowchart of the process is provided in the Economic Analysis Section of the Supply Plan narrative as Figure EA-1. At a high level, the IRP process starts with a forecast of customer loads and assesses a range of energy supply alternatives to identify options for meeting Nevada's energy needs. The Resource Planning team uses advanced PLEXOS energy modeling software to determine the most economic options that meet the reliability and sustainability needs of the state. After performing that analysis, the results are assessed and ultimately a preferred plan and at least one alternative plan are identified. As discussed in more detail in Kim Williams' testimony, multiple updates were made in the economic analysis process for this filing including refreshing the effective load carrying capability ("ELCC") and planning reserve margin ("PRM"). Through this filing, the Companies ask the Commission to determine that the Preferred Plan that the Companies have selected is reasonable and prudent and authorize the Companies to take all actions necessary during the three-year action plan period, 2025-2027, to implement the Preferred Plan.

Embodied in this 2024 Joint IRP is an updated load forecast, a market fundamentals forecast including fuel and purchase power pricing, a supply plan that includes a transmission plan, a renewable energy plan, a generation section, economic analysis and finally a financial plan. Embedded in the 2024 Joint IRP is a Joint ESP, as required by Nevada Administrative Code ("NAC") § 704.9482. The Joint ESP and its associated technical appendices are located in stand-alone volumes filed as part of the 2024 Joint IRP. The 2024 Joint IRP also includes a demand side management ("DSM") plan and a distributed resource plan ("DRP"). The 2024 Joint IRP addresses renewable portfolio standard ("RPS") and capacity concerns created by load growth, incremental cancellations of previously approved projects and continues to advance resource sufficiency for the Companies as required for participation in WRAP, a future day-ahead market, and/or a future regional transmission organization ("RTO"). The 2024 Joint IRP also outlines the Companies' intent to join the California Independent System Operator ("CAISO") Expanded Day-Ahead Market ("EDAM").

IV. THE PREFERRED AND ALTERNATE PLANS

8. Q. PLEASE DESCRIBE THE PREFERRED PLAN.

A. After assessing several different plans, the Companies identified the Balanced Plan as the Preferred Plan. The Balanced Plan is the least cost plan for customers over the 26-year planning horizon and was constructed to not only help the Companies serve the existing load on the system but to also lay the groundwork to meet future demand that is forecasted to grow at a record pace. This Balanced Plan is comprised of a robust renewable resources portfolio which will help the Companies meet future RPS requirements and continue to position Nevada to be a leading renewable energy producer. The plan also includes significant transmission investments to ensure future load growth can occur and the electric system remains reliable moving forward. More specifically, the Preferred Plan includes requests for approval for the following supply plan additions:

- Construction of the Valmy Simple-Cycle Plant project consisting of two Hydrogen-Capable Natural Gas Combustion Turbines ("CTs") totaling approximately 411 MW located at the Valmy Generating Station, in Northern Nevada;
- Approval of three Power Purchase Agreements ("PPAs") totaling 1,028 MW Solar Photovoltaic ("PV") and 1,028 MW Battery Energy Storage System ("BESS"). These PPAs are:
    - Dry Lake East which is a 200 MW PV and 200 MW BESS project located in Clark County, Nevada, with an in-service date of December 1, 2026.
    - Boulder Solar III which is a 128 MW PV and 128 MW BESS project located in Clark County, Nevada, with an in-service date of June 1, 2027.
    - Libra which is a 700 MW PV and 700 MW BESS project located near the Mineral County/Lyon County border, Nevada, with an in-service date of December 1, 2027.

9. Q. PLEASE DESCRIBE HOW THE COMPANIES SELECTED THE PREFERRED PLAN

A. The Preferred Plan helps position Nevada for economic growth and addresses capacity, energy, and RPS concerns created by dramatically growing demand and cancellations of previously approved renewable projects. With the updated load forecast presented in this 2024 Joint IRP, the Companies have a growing need for resources. The Preferred Plan provides the most appropriate balance of resources to mitigate the risk of exposure to uncertain market purchases without creating excessive long positions. This balanced approach best supports the Companies' efforts to become resource sufficient for future participation in a day-ahead market, WRAP, and a future RTO. The Preferred Plan also has the lowest present worth of revenue requirements ("PWRR") of all plans in the 20-year and 26-year study periods due in large part to its balance of renewable, storage, and cost-effective firm dispatchable resources. The Valmy Simple-Cycle Plant, which is two hydrogen-capable natural gas CTs at the Valmy location, will also allow for the Valmy steam plant must-run requirement to be eliminated which is explained further in the Transmission narrative. The elimination of the Valmy must-run requirement, which would have otherwise been required in perpetuity, eliminates what would have been a constant source of carbon dioxide emissions at Valmy. This aligns with the intent of the balanced approach of the Preferred Plan to achieve a lower carbon future.

10. Q. WHY DOES RESOURCE ADEQUACY REMAIN A CRITICAL FACTOR IN THE COMPANIES' PLANNING AND DECISION MAKING?

A. Resource adequacy, as demonstrated in several dockets, has been an increasingly important focus of the Companies, as well as of the Commission, over the past several years. Reliability assessment reports published by both the North American

Electric Reliability Corporation ("NERC") and the Western Electricity Coordinating Council ("WECC") continue to highlight the continued concerns throughout the western region.

In December 2023, NERC released their latest Long-Term Reliability Assessment. The report labels the entire Western Region as an "Elevated Risk"[1] area which means "they may face challenges meeting load under extreme conditions."[2] The report goes on to state that the WECC-NW and WECC-SW regions, both of which Nevada is a part, are "projected to be at risk of resource shortfalls during extreme summer weather conditions after 2024."[3] The report also highlights that the WECC-CA/MX region, which includes California and a small part of Mexico, has similar risks and that "loss-of-load and unserved energy risks emerge in 2026."[4]

In November 2023, WECC released its latest Western Assessment of Resource Adequacy. The report tells a similar story to the NERC assessment but highlights that resource adequacy risk has grown since its previous reports, "Resource adequacy remains a critical risk in the Western Interconnection and continues to challenge industry planners, operators, regulators, and partners. Resource adequacy risks over the medium and long term have increased significantly compared to last year's assessment."[5] The report goes on to highlight "Based on the resource planning information provided by balancing authority ("BAs"), and WECC's energy based probabilistic analysis, demand-at-risk hours increase significantly

[1] NERC, 2023 Long-Term Reliability Assessment at page 6, available at https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.
[2] *Id.* at 7.
[3] *Id.* at 9.
[4] *Id.* at 9.
[5] WECC, 2023 Western Assessment of Resource Adequacy at 2, available at www.wecc.org/ReliabilityAssessments/Pages/defaults.aspx.

over the next 10 years."[6] A number of factors contribute to the increasing resource adequacy concerns, including the retirement of thermal generation, greater reliance on variable resources, which may not be available during peak hours without storage, transmission curtailments within the CAISO, and continued load growth on the system.

As discussed further in the testimony of expert witness Nick Schlag, multiple factors continue to create new challenges that introduce additional resource adequacy risks to the NV Energy system and the western region. Maintaining a reliable electric system is critical for Nevada and any failure to do so could result in potentially life-threatening conditions for Nevada residents. As these risks continue to grow in Nevada, the Companies must continue to keep resource adequacy as a critical factor in its planning and decision making.

11. Q. DOES HAVING A LARGE OPEN POSITION PUT THE COMPANIES AT GREATER RISK?

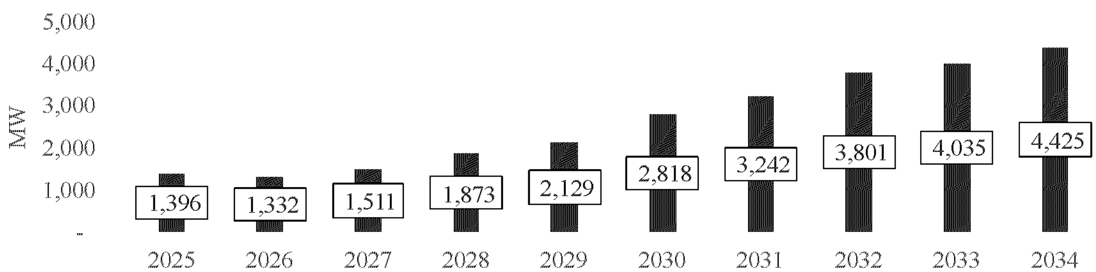
A. Yes. The Companies recognize that significant changes in the market make it increasingly risky and unreliable to rely on the market and it is no longer responsible or prudent to rely on the market to meet peak capacity needs. As supported by WECC, NERC, and E3, warning signs abound in the western region and load shed continues to be a legitimate risk for utilities. As discussed in more detail in Nick Schlag's testimony, it is prudent for the Companies to continue to make efforts to lower its open position and such action is aligned with efforts by other major utilities in the western United States.

[6] *Id.* at 23.

12. Q. DOES THE PREFERRED PLAN HELP THE COMPANIES REDUCE THEIR OPEN POSITION DURING THE STUDY PERIOD?

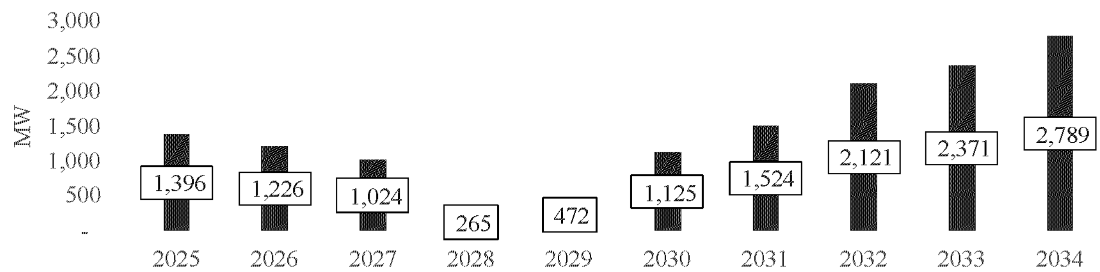
A. Yes, it does. This reduction in the open position also supports the Companies' efforts to participate in the Western Resource Adequacy Program ("WRAP") to increase reliability for the state of Nevada. The projected open position based on existing and approved projects is 1,332 MW in 2026 before steadily increasing each year after.

NV ENERGY CAPACITY NEEDS
EXISTING & APPROVED RESOURCES



While the Preferred Plan does not fully resolve the Companies' capacity deficiency, it lowers the open position significantly. When removing future unidentified placeholder resources from the Preferred Plan, the projected open position is lowered to under 500 MW for both 2028 and 2029 before rapidly increasing in 2029 and beyond.

PREFERRED PLAN CAPACITY NEEDS



While the resources proposed in the Preferred Plan lowers the open position to a reasonable and reliable level by 2028, it will be a continuous effort over the next ten years of identifying, seeking approval, and constructing additional resources to address the expected significant load growth in Nevada. As the Companies work to solve the reliability challenges that have grown in recent years, moving forward with a balanced plan of in-state resources that reduce the open position as much as possible is critical to supporting resource adequacy efforts in the state of Nevada.

13. Q. THE COMPANIES ARE REQUESTING APPROVAL OF FOSSIL GENERATION AS A PART OF THE PREFERRED PLAN. ARE THE COMPANIES DEVIATING FROM THEIR CLEAN ENERGY GOALS?

A. No, the Companies are not deviating from their clean energy goals and remain committed to Nevada's sustainability goals. The Companies are eliminating coal from the existing resource portfolio by the end of 2025 and continue to deliver on the commitment to reduce carbon emissions. The Preferred Plan achieves or exceeds the RPS in all years and, as in recent IRP filings, targets the Companies' proportionate share of the state's 2050 clean energy goal. The proposed Valmy Simple-Cycle Plant eliminates the Valmy must-run requirement which would have otherwise been required in perpetuity. The proposed peaking generators eliminate what would have been a constant source of carbon emissions at Valmy. The Valmy Simple-Cycle Plant is expected to have an annual capacity factor of only 12 percent to 17 percent between the years 2028 to 2030, and less than 7 percent annual capacity factor from 2031 to 2050. As well, these new peaking generating units are capable of operating on a 15 percent hydrogen mixture today, with the plan towards operation on 100 percent hydrogen in the future, as further described in the Generation narrative. The Valmy Simple-Cycle Plant provides needed capacity contribution that does not diminish over the study period due to ELCC saturation and results in a very prudent and economic future. As discussed further in the testimony of Kim Williams, firm dispatchable resources, which are modeled today as gas turbines, contribute much more significantly to firm capacity in 2050 in the Preferred Plan than they do to energy production, resulting in a positive impact on resource adequacy with minimal potential carbon dioxide emissions. Further, the Preferred Plan also includes multiple renewable placeholders to ensure the Companies continue to meet the RPS requirements in all years going forward and additional transmission expenditures to allow further renewable project buildouts in the future.

14. Q. DO THE COMPANIES NEED THE SOLAR RESOURCES IN THE PREFERRED PLAN TO MEET THE STATE-MANDATED RPS REQUIREMENTS?

A. Yes. While discussed in greater detail in the Renewables section of the Supply Plan and in Sean Spitzer's testimony, moving forward with the proposed Solar and BESS projects is critical in helping the Companies meet the state-mandated RPS requirement. While the Companies have been successful in exceeding the RPS requirement to date, there have been several renewable project cancellations and the RPS requirement will increase to 42 percent in 2027, and 50 percent in 2030, and remain at 50 percent each calendar year thereafter. An increasing load forecast expands retail sales which in turn escalate the requirement to demonstrate RPS compliance. Under the Preferred Plan, the Companies would remain compliant by credit sharing between Nevada Power and Sierra and by utilizing the surplus of credits the Companies have built. As shown in Table REN-1 in the Renewables Narrative, the projected surplus or 'bank' of credits drops approximately 92 percent from just under 3.5 million credits in 2024 to 270,000 credits in 2028. Without the proposed resources in the Preferred Plan, the Companies would utilize all surplus credits and be projected to be unable to meet the RPS requirement starting in 2027 for Sierra.

15. Q. PLEASE DESCRIBE THE ALTERNATE PLAN, LOW CARBON PLAN, AND NO OPEN POSITION PLAN.

The Alternate Plan, also known as the Renewable Plan, includes the same proposed renewable and storage resources as the Preferred plan, but does not include the Valmy Simple-Cycle Plant that is included in the Preferred Plan. The plan results in larger amount of BESS being built over the 26-year study period. The named placeholders in the plan are identical to those in the Preferred Plan. While the projects add near-term capacity in the same early years as the Balanced Plan, less capacity is added in 2028. The lack of near term CTs results primarily in incremental BESS placeholders in 2030 in order to ensure similar open positions to the Balanced Plan. Without the two hydrogen-capable natural gas CTs at the Valmy location, the Valmy must-run requirement continues in perpetuity in this plan due to the load growth in the region. Without near-term CTs, this plan has a larger buildout of BESS over the 26-year study period which leads to a significant increase in cost. The BESS, unlike CTs, is subject to a declining ELCC and has a shorter asset life than CTs, both of which drive an increased BESS buildout through the study period. As shown in the Economic Analysis Section of the narrative, the PWRR increase from the Preferred Plan to the Alternate Plan for the 20-year PWRR period is $300 million and for the 26-year PWRR period is over $1 billion. The Commission should only consider the adoption of the Alternate Plan if it is willing to accept the resource adequacy risk and increased cost associated with a larger amount of 4-hour BESS compared with CTs and accept a must-run in perpetuity at Valmy.

The Low Carbon Plan creates a buildout that meets the 80 percent reduction in carbon dioxide emissions from 2005 levels by 2030. This is a required alternative plan per NAC § 704.937(1). This plan results in a significant increase in renewable energy projects being built between the years of 2028 to 2030 to achieve this carbon reduction goal. The Low Carbon Plan adds no near-term thermal generation, thus the Valmy must-run requirement continues in perpetuity in this plan due to the load growth in the region. The Low Carbon Plan has the highest PWRR in the 20-year and 26-year study period of all plans.

The No Open Position Plan creates a buildout that closes the open position by 2028 and keeps it closed for the remainder of the 26-year study period. This plan has the same proposed resources as the Preferred Plan, but also includes an additional set of CTs located at Harry Allen going in-service in 2030. This plan results in a larger buildout of gas and firm dispatchable resources to achieve and maintain the zero open position target.

All four alternative plans address the need for RPS-contributing projects and provide capacity by proposing projects that reduce the Companies' open position. The plans are responsive to the continued uncertain availability and deliverability of market capacity, consistent with advancing resource sufficiency as required for participation in the WRAP. All plans meet the PRM requirement, the state's RPS requirements, and the expected level of Nevada GreenEnergy Rider ("NGR") participation, plus target the Companies' proportionate contribution to the state's 2050 clean energy goal. The PWRR of all plans is shown in the table below.

	20 Year PWRR 2025-2044 (million $)	26 Year PWRR 2025-2050 (million $)	20 Year PWRR Change from Least Cost Case (million $)	26 Year PWRR Change from Least Cost Case (million $)	20 Year PWRR Rank Order	26 Year PWRR Rank Order
Balanced Plan	$ 32,931	$ 41,294	$ -	$ -	**1**	**1**
Renewable Plan	$ 33,252	$ 42,342	$ 321	$ 1,047	**2**	**2**
No Open Position	$ 35,614	$ 46,293	$ 2,683	$ 4,998	**3**	**3**
Low Carbon	$ 38,520	$ 47,115	$ 5,590	$ 5,821	**4**	**4**

16. Q. PLEASE SUMMARIZE YOUR SUPPORT OF THE PREFERRED PLAN.

A. The Preferred Plan is a balanced solution that helps to address resource adequacy concerns while still meeting state renewable requirements. It reduces risk to market uncertainty by lowering the open position and advances the Companies' direction toward participation in WRAP, a future day-ahead market, and/or a future RTO. Of the plans that were evaluated, the Preferred Plan has the lowest PWRR and lowest present worth of societal costs ("PWSC"). It balances incremental capacity and RPS contribution with overall cost and decarbonizing goals, which I support as a prudent direction for the future.

V. GREENLINK

17. Q. WHY ARE THE COMPANIES BRINGING FORWARD UPDATED COSTS FOR THE GREENLINK NEVADA TRANSMISSION PROJECT?

The Companies continue to develop the Greenlink Nevada Transmission project. As detailed in the Transmission Section of the narrative, there have been increases in the estimated total cost of the Greenlink Nevada Transmission projects. Due to the material size of the cost increases, the Companies are bringing forth the updated project costs for continued approval by the Commission. The Companies maintain the Greenlink projects are vital to the robust development of renewable resources throughout Nevada as well as low-cost reliability for the growing load, and the Greenlink project remains the best alternative to meet the Companies' future transmission needs despite the cost increases. Although the Greenlink transmission project has experienced significant cost escalation, all other transmission alternatives would also experience similar cost escalation as discussed in the testimony of Shahzad Lateef and John Tsoukalis. The only practical alternative to the construction of Greenlink is the construction of additional generation closer to the load centers with the required transmission upgrades to connect that generation as further described in the Transmission narrative and Charles Pottey's testimony. This alternative is evaluated in the No Greenlink illustrative case discussed in the testimony of Kim Williams, which demonstrates that similar reliability cannot be achieved at a lower cost without Greenlink. In addition, this alternative would not provide any additional system import and export capacity nor transfer capacity between northern and southern Nevada. As discussed in the testimony of Kiley Moore, it would also not meet the Companies' obligations under the Open Access

Transmission Tariff ("OATT") to provide necessary system import capacity to serve forecasted load growth for transmission Network customers.

VI. REGIONAL MARKET DEVELOPMENT

18. Q. WHAT IS THE STATUS OF THE WRAP AND ARE THE COMPANIES STILL MOVING FORWARD WITH PARTICIPATION?

A. The Federal Energy Regulatory Commission approved the WRAP tariff in February 2023. The Companies continue to participate in the transitional non-binding phase as an active member as the program further develops into a binding phase. There are currently 22 entities that are participating in the program which makes the total WRAP footprint more than 58,000 MW. The first binding season has been pushed back from Summer 2025 to Summer 2027, due to a lack of participation, and the Companies have pushed their first elected binding season to the Winter 2027-2028 season which will allow the Companies additional time to continue to add resources in order to pass the forward-showing requirement for the Summer 2028 season. The Western Power Pool and Southwest Power Pool continue to develop many business practices that fill in the details of the program in preparation for the first binding season. The draft versions of these business practices will continue to be available on their websites for public comments.

19. Q. WHY IS THE WRAP IMPORTANT FOR THE WESTERN INTERCONNECTION?

A. Regional resource adequacy is important for every entity in the West, including NV Energy. Historically, every entity has planned only for itself with many entities relying on the market (i.e. imports) to meet some of their load requirements. This is one of the major contributing factors to the resource adequacy issues that have presented themselves over the past several summers. The WRAP is the first regional reliability planning and compliance program in the history of the West. It will deliver a region-wide approach for assessing and addressing resource adequacy and provide an important step forward for reliability in the region. With the majority of entities in the West now planning to participate in the WRAP, every utility will be required to be resource sufficient, thus increasing resource adequacy for the region as a whole.

20. Q. DO THE COMPANIES CURRENTLY HAVE ENOUGH RESOURCES TO PARTICIPATE IN THE WRAP?

A. No. NV Energy will face binding compliance obligations for participation. Failure to meet these requirements could result in significant financial penalties. The penalty calculation is based on the Cost of New Entry ("CONE") which is based on the cost of building a new resource. In addition, there are adders that can be applied based on the deficiency volumes and frequency. For example, if a participant fails multiple months in a single season, a penalty adder of 200 percent is applied to the incremental deficiency. Without any new resource additions, initial projections forecast the Companies to have a deficiency of more than 2,100 MW for September of 2028. With the proposed resources of the Preferred Plan, the deficiency shrinks to approximately 540 MW, which the Companies can attempt to acquire on a short-term basis. These initial projections are explained further in the Day-Ahead Markets and Regional Transmission Organization narrative. While the Companies could potentially rely on shorter-term contracts or market purchases to help meet the requirements, these short-term transactions can only be counted in very specific circumstances. For example, contracts must be executed before the forward showing is submitted which occurs seven months in advance of the season. Additionally, the contracted supply must meet strict guidelines and include an attestation that the requirements have been met by both companies in order to count towards the forward showing requirements. Each contract must have a specific source identified, either resource specific or a system sale that is surplus, the transaction must include and be able to show firm transmission from source to sink, and each party must provide a signed affidavit affirming the capacity being utilized in the transaction will not be committed to other needs. The majority of purchases that have been available to NV Energy over previous summers would not meet these guidelines and would not count towards the forward showing requirement. Any purchases out of the CAISO market would not count towards the forward showing. Overall, this type of market purchase has limited availability and would come at a high price.

21. Q. WHAT IS THE STATUS OF DAY-AHEAD MARKET DEVELOPMENT AND WHEN DO THE COMPANIES ANTICIPATE MAKING A DECISION ON WHICH MARKET TO JOIN?

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 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, the

Companies intend to request authorization from the Commission to participate in the CAISO Extended Day-Ahead market ("EDAM"). As the second participant in the Western Energy Imbalance Market ("WEIM"), the Companies have experienced significant economic, reliability, and environmental benefits. Having developed a market that includes more than 80 percent of load in the WECC, NV Energy would hope to preserve as much of that size and diversity as possible while expanding the scope of the organized market services. Critical to NV Energy's decision is the expected EDAM footprint. The anticipated participation by CAISO, PacifiCorp, Balancing Authority of Northern California, Los Angeles Department of Water and Power, Portland General Electric, and Idaho Power, provides a significant degree of interconnectivity and supports a diversity of resources. Moreover, the approval of the SWIP-North transmission project by CAISO and Idaho Power Company will only enhance the transfer capacity of the existing ON Line transmission line in Nevada, bringing even greater benefits to all EDAM participants.

22. Q. HOW DO THE COMPANIES PLAN TO MEET SENATE BILL 448 ("SB448") REQUIREMENTS TO JOIN AN RTO BY 2030?

A. NV Energy recognizes its obligation under SB 448 to seek and evaluate viable RTO options. The decision to proceed with EDAM is consistent with the desire of many of the other Western Balancing Authorities to pursue market expansion on an incremental basis as a means of capturing substantial customer benefits on a least-cost, least regrets basis. 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+, WRAP, and any other proposed expansion of organized

Western wholesale electric market participation, NV Energy staff will continue to make all reasonable efforts to comply with the SB 448 mandate. A proposed roadmap to a viable RTO is provided and discussed in the Day-Ahead Markets and Regional Transmission Organization Section of the narrative.

23. Q. WOULD JOINING THE WRAP, A DAY-AHEAD MARKET, OR AN RTO, IMPACT THE COMPANIES' NEED FOR THE GENERATING RESOURCES PROPOSED IN THIS FILING?

A. No. While the participation in a future market is expected to provide benefits by allowing the Companies to optimize their available capacity across a broader footprint, the Companies must first be able to pass forward showing requirements associated with each market design. The purpose of these forward showing requirements is to show the market operator and other market participants that the Companies are able to provide enough capacity to cover their own load requirements plus an uncertainty margin specified by that market, which they currently cannot do. Markets typically design a resource sufficiency requirement in order to prevent any participant from leaning on other market participants. The failure to meet resource sufficiency requirements could result in both financial penalties and/or a lack of access to available supply in the market.

VI. CONCLUSION

24. Q. PLEASE SUMMARIZE YOUR TESTIMONY

A. The Preferred Plan is the least cost plan for customers over the 26-year study horizon and was constructed to not only help the Companies serve the existing load on the system but to also lay the groundwork to meet future demand that is forecasted to grow at a record pace. This balanced approached is comprised of the most renewable resources ever requested by the Companies which will help the Companies meet future RPS requirements and continue to position Nevada to be a leading renewable producer. The Companies are not deviating from their clean energy goals and remain committed to Nevada's sustainability goals. The Companies are eliminating coal from the existing resource portfolio by the end of 2025 and continue to deliver on the commitment to reduce carbon emissions. The Preferred Plan achieves and exceeds the RPS in all years and, as in recent IRP filings, targets the Companies' proportionate share of the state's 2050 clean energy goal. The Preferred Plan is a balanced solution that helps to address resource adequacy concerns while still meeting state renewable requirements. Resource adequacy remains a significant challenge, and the Preferred Plan reduces the market uncertainty risk by lowering the open position and advances the Companies' direction toward participation in WRAP, a future day-ahead market, and a future RTO. Of the plans that were evaluated, the Preferred Plan has the lowest PWRR and lowest PWSC and it balances incremental capacity and RPS contribution with the overall cost and decarbonizing goals, which I support as a prudent direction for the future.

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

A. Yes.

EXHIBIT ATKINS-DIRECT-1

STATEMENT OF QUALIFICATIONS

Ryan Atkins
6226 W. Sahara Ave. Las Vegas, NV 89146
Ryan.atkins@nvenergy.com
(702) 402-1788

PROFESSIONAL EXPERIENCE

NV Energy, Las Vegas, NV
Vice President, Resource Optimization & Planning, December 2022 - Present
- Oversight of Resource Optimization and Resource Planning teams
- Development of the Companies' Integrated Resource Plans, Energy Supply Plans, and Gas Information Reports
- Optimization of energy trading activities

Senior Director, Trading Analytics and Operations, February 2021 – December 2022
- Responsible for directing the development and execution of strategies aimed at maximizing the value of the Companies' portfolio of energy supply resources.

Director, Process Improvement, May 2018 – February 2021
- Directed team in charge of business optimization and innovation efforts including automation, process mining, and benchmarking.

Project Manager, Forward Trading, August 2017 – May 2018
- Optimized NV Energy generation portfolio and executed long term power transactions consistent with the Company's risk management guidelines.
- Managed greenhouse gas compliance obligations.

Senior Power Trader, May 2013 – August 2017
- Optimized NV Energy generation portfolio and executed day-ahead power transactions consistent with the Company's risk management guidelines.

Iberdrola Renewables, Portland, OR
Real-Time Power Trader, September 2011 – May 2013
- Executed short-term power transactions to optimize Iberdrola's western energy fleet of wind, hydro, and thermal generation.

NV Energy, Las Vegas, NV
Gas Trader, June 2010 – September 2011
- Optimized NV Energy's gas supply and transport portfolio consistent with the Company's risk management guidelines.

Real-Time Power Trader, August 2007 – June 2010
- Optimized NV Energy generation portfolio on an hour to hour basis and executed short-term hourly power transactions consistent with the Company's risk management guidelines.

EDUCATION

University of Idaho, Moscow, ID
Bachelor of Science, 2007

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, RYAN ATKINS, 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: May 31, 2024

RYAN ATKINS

TIMOTHY POLLARD

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2024 Joint Triennial Integrated Resource Plan (2025–2044)
Docket No. 24-05___

Prepared Direct Testimony of

Timothy Pollard

I. INTRODUCTION

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 Rates and Regulatory Affairs 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. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE IN THE UTILITY INDUSTRY.

A. I have been employed by NV Energy in the Rates and Regulatory Affairs department since 2007. Until 2022, I worked as a Technical Lead where my main focus was related to regulatory cost of service and rate design items. In my current position, my primary focus is on long-term load forecasting and load research issues for the Companies. I was also previously employed by the Companies in 2004 as a Load Forecasting Economist within the Resource Planning department.

I have been an expert witness before the Public Utilities Commission of Nevada ("Commission") regarding load forecasts, cost of service, and regulatory pricing issues in support of various Rate & Regulatory Affairs department proceedings. My educational background, previous positions and professional experience are summarized in the statement of qualifications attached as **Exhibit Pollard-Direct-1**.

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

A. My current responsibilities include leading and overseeing the Companies' load forecasts and historical load research activities. This includes all technical aspects of their historical and forecast class load data used for filings with the Commission.

4. Q. **HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY WITH THE COMMISSION?**

A. Yes. Most recently, I provided testimony to the Commission in the 2024 Sierra electric and gas General Rate Case proceedings Docket Nos. 24-02026 and 24-02027. A full list of cases in which I have provided testimony before the Commission can be found in **Exhibit Pollard-Direct-1**.

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

A. The purpose of my testimony is to support updates to the long-term load forecast for this Triennial 2024 Joint Integrated Resource Plan ("2024 Joint IRP"), with the corresponding Technical Appendices. I also support updates to the rates to be paid by those customers who choose to elect service from another energy provider through the 704B exit process for the action plan period in this proceeding.

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

6. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?

A. I am sponsoring the following Exhibits:

- **Exhibit Pollard-Direct-1** – Summary of Qualifications.

I am also sponsoring the Load Forecast Narrative and Load Forecast Technical Appendices provided with the filing. Because this material is identical for both the Energy Supply Plan ("ESP") and 2024 Joint IRP Forecast, these materials are physically located in the Technical Appendices accompanying the load forecast narrative for the 2024 Joint IRP. These include:

- IRP LF-1 2024 Joint IRP Load Forecast Technical Appendix (portions of which are confidential);
- IRP LF-2 State Demographer Long-Term Population Projections, 2022-2041;
- IRP LF-3 State Demographer 2022 Governor Certified Series – Population Estimates of Nevada's Counties;
- IRP LF-4 Las Vegas Convention and Visitors Year to Date executive summary for 2023;
- IRP LF-5 2023 CBER Clark County Population Forecast, June 2023;
- IRP LF-6 S&P Global HIS Economics 2023 (confidential);
- IRP LF-7 Itron, Inc. Statistically adjusted end-use ("SAE") model overview;
- IRP LF-8 Applied Analysis Nevada Economic Review report.

7. Q. ARE YOU FILING WORKPAPERS WITH THE 2024 JOINT IRP FORECAST?

A. Yes, as a general practice before the Commission, a comprehensive set of executable files demonstrating the calculations for the load forecasting data I am providing will be supplied on electronic media for this filing. In accordance with the stipulation accepted by the Commission in the Third Amendment to the 2021 Joint IRP (Docket No. 22-09006), a workpaper index is provided to interested parties as part of the filing in order to assist with detailing the steps used to develop the forecast.

8. Q. ARE ANY OF THE MATERIALS YOU ARE SPONSORING CONFIDENTIAL?

A. Yes. The customer-specific information included in the IRP LF-1 Technical Appendix workpapers and third-party proprietary information presented in Technical Appendix LF-6 are confidential information.

9. Q. FOR HOW LONG DO THE COMPANIES REQUEST CONFIDENTIAL TREATMENT OF THIS INFORMATION?

A. The requested period for confidential treatment is five years.

10. 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 FULLY INVESTIGATE THE INFORMATION SET FORTH IN THIS FILING?

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.

11. Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is separated into three sections. They are:

- Section I – Introduction
- Section II – 2024 Joint IRP Load Forecast
- Section III – 704B Rate Calculations

II. 2024 JOINT IRP LOAD FORECAST

12. Q. PLEASE SUMMARIZE THE COMPANIES' REQUESTS REGARDING THE 2024 JOINT IRP FORECAST.

A. The 2024 Joint IRP Forecast provides the foundation for all other load forecasts included in this filing. The Companies request the following regarding the 2024 Joint IRP Forecast covering the 2025 to 2044 period:

- A finding, consistent with NAC § 704.9321, that the 2024 Joint IRP Forecast is based on substantially accurate data, adequately demonstrated and defended, and adequately documented and justified.
- A finding that the 2024 Joint IRP Forecast, as described in the Narrative and the Technical Appendices, as well as in my testimony, contains all of the items required by NAC § 704.925 and other applicable regulations.
- A finding that the 2024 Joint IRP Forecast is suitable for making long term planning decisions over the 2025 to 2044 period.

13. Q. PLEASE SUMMARIZE THE COMPANIES' PROPOSED 2024 JOINT IRP FORECAST.

A. The 2024 Joint IRP Forecast provides the foundation for all other load forecasts included in this 2024 Joint IRP filing. The 2024 Joint IRP Forecast includes the following:

- An updated economic outlook issued in June 2023,

- Refinements to weather normalization adjustments to consider monthly regression coefficients, rather than an annual linear regression,
- Development of a specific solar photovoltaic ("solar PV") Net-Energy Metering ("NEM") customer and sales forecast, to incorporate strong recent trends in rooftop solar adoption,
- Estimated adoption rates of electric vehicles ("EV"), incorporating findings from the forecast developed by Energy and Environmental Economics, Inc. ("E3") for this filing,
- Energy Efficiency ("EE") program savings updates through October 2023, representing 1.1 percent of annual sales as considered in the last approved forecast that was accepted by stipulation forecast in Docket No. 22-09006,
- Proposed Demand Side Management ("DSM") savings, included in the Companies' Preferred Plan, are incorporated into incremental forecast scenarios,
- Removal of Demand Response ("DR") program event savings from the forecast to reflect the use of these programs as a system resource within the Loads & Resources ("L&R") tables, and
- Expected changes in large customer business activity, which are discussed below.

14. Q. WHAT IS THE IMPACT OF THE UPDATES FROM THE PREVIOUSLY APPROVED FORECAST?

A. Table Pollard-Direct-1 below summarizes the change in forecast annual energy gigawatt-hour ("GWh") sales and peak megawatts ("MW") over the 2025–2044 period for the updated forecast. For the three-year action plan period 2025 through 2027, the Compound Annual Growth Rate ("CAGR") of the annual retail energy for the Companies is 1.9 percent (1.1 percent at Nevada Power and 3.3 percent at Sierra). Annual energy consumption during this period increases 2,059 gigawatt-hours ("GWh") for the combined NV Energy system, with 778 GWh at Nevada Power and 1,280 GWh at Sierra. The CAGR of the Companies' coincident peak is 0.9 percent (0.4 percent at Nevada Power and 1.9 percent at Sierra). System Peak Demand is expected to increase 226 MW for the combined system during the three-year action plan period, with 87 MW at Nevada Power and 134 MW at Sierra.

TABLE POLLARD-DIRECT-1
COMPANIES' ENERGY AND PEAK FORECAST COMPARISON

	Native Energy (GWh)			Peak (MW)		
Year	NVE	NPC	Sierra	NVE	NPC	Sierra
2025	34,891	22,544	12,346	8,690	6,630	2,353
2026	35,670	22,933	12,737	8,785	6,631	2,374
2027	36,950	23,323	13,627	8,916	6,717	2,487
2028	38,657	23,816	14,841	9,206	6,864	2,647
2029	40,142	24,208	15,934	9,439	6,909	2,851
2030	42,504	24,724	17,780	9,948	7,117	3,072
2031	44,880	25,232	19,647	10,278	7,205	3,416
2032	47,265	25,816	21,449	10,698	7,365	3,564
2033	48,082	26,202	21,880	10,778	7,455	3,641
2034	48,974	26,658	22,316	11,084	7,613	3,801
2035	49,949	27,118	22,831	11,205	7,702	3,852
2036	51,067	27,636	23,431	11,488	7,857	3,891
2037	52,089	28,079	24,009	11,718	8,049	3,959
2038	53,389	28,726	24,663	11,871	8,156	4,053
2039	54,739	29,392	25,347	12,128	8,332	4,164
2040	56,289	30,212	26,077	12,563	8,566	4,362
2041	57,638	30,878	26,760	12,800	8,659	4,399
2042	59,150	31,609	27,542	13,015	8,878	4,595
2043	60,380	32,020	28,360	13,290	9,000	4,594
2044	62,055	32,753	29,302	13,501	9,110	4,734
CAGR						
2025-2027	1.9%	1.1%	3.3%	0.9%	0.4%	1.9%
2025-2034	3.4%	1.7%	6.1%	2.5%	1.4%	4.9%
2025-2044	2.9%	1.9%	4.4%	2.2%	1.6%	3.6%

For the twenty-year forecast period 2025 through 2044, the CAGR of the annual retail energy for the Companies is 2.9 percent (1.9 percent at Nevada Power and 4.4 percent at Sierra). Annual energy consumption increases 27,164 GWh for the combined NV Energy system, with 10,209 GWh at Nevada Power and 16,955 GWh at Sierra. The CAGR of the Companies' coincident peak is 2.2 percent (1.4 percent at Nevada Power and 4.9 percent at Sierra). System Peak Demand is expected to increase 4,811 MW for the combined system during this period, with 2,480 MW at Nevada Power and 2,381 MW at Sierra.

15. Q. DOES THE 2024 JOINT IRP FORECAST CONSIDER THE IMPACT OF APPLICABLE NEW TECHNOLOGIES AND THE IMPACT OF APPLICABLE NEW GOVERNMENTAL PROGRAMS OR REGULATIONS (SEE NAC § 704.925(4))?

A. Yes. The customer class sales regression modeling for the 2024 Joint IRP Forecast includes variables constructed from estimated historical and forecasted appliance saturations and efficiencies, building characteristics and square footage. These estimates and forecasts include the effects of new technologies and government programs. Further, the 2024 Joint IRP forecast separately forecasts the NEM customer growth over the 2025–2044 as customers choose to install rooftop PV generation at their premises.

13. Q. DOES THE 2024 JOINT IRP FORECAST CONSIDER THE IMPACT OF CUSTOMERS WHO ACQUIRE ENERGY PURSUANT TO NRS § 704.787 OR NRS CHAPTER 704B (SEE NAC § 704.925(5))?

A. Yes. Customers who are expected to procure energy from an alternative supplier and move to distribution only service ("DOS") have been removed from the load forecast. In northern Nevada, Newmont, now a subsidiary of Nevada Gold Mines, Inc., moved its bundled load to DOS on February 1, 2022, and is reflected as a DOS customer in the 2024 Joint IRP Forecast. In southern Nevada, there are no existing customers that are pending to move to DOS in the 2024 Joint IRP Forecast. However, an additional load forecast was developed to incorporate the 704B eligible load limits over the action plan period, which is discussed further in Section III of my testimony.

15. Q. HAVE THE COMPANIES MADE ANY CHANGES TO THEIR FORECAST METHODOLOGY SINCE THE FORECAST APPROVED BY THE COMMISSION IN THE COMPANIES' THIRD AMENDMENT TO THEIR 2021 JOINT IRP?

A. Yes, while the forecast continues to be developed using a bottom-up data-driven modelling approach, there are several revisions to the methodology included in the development of the 2024 Joint IRP forecast. I discuss these revisions, as well as updates to inputs to the forecast, below.

In this filing, the process begins with hourly class load data, rather than monthly billing data as had been used in previous forecast updates. The process begins by estimating customer class sales and customer models with class-level sales forecasts that are ultimately translated into system energy requirements.

Next, with the incorporation of hourly customer data, the weather normalization adjustments have been refined to consider each month separately, rather than relying on an annual linear regression model. The result is separate customer responses due to weather for individual months across the year. The definition of normal weather continues to use the trended normal weather approach as supported by Itron, Inc. and approved by the Commission in the Sierra's 2019 GRC.[1]

Third, customers who choose to install private generation behind their meter are now separately forecasted following trends in recent years. The impact of these customer decisions are now reflected in overall sales reductions, as well as the system impact of their self-generation previously reflected within the L&R tables.

Fourth, DR event savings are no longer included as a load modifier within the load forecast. These events and related savings are now reflected as a resource within the L&R tables.

Lastly, the 2024 Joint IRP Forecast update includes expected loads for Major Projects currently in the Study Phase of the interconnection process, albeit at significantly reduced levels from those requested by customers. In previous updates, only those projects with signed Rule 9 agreements were incorporated into the retail sales forecasts.

17. Q. PLEASE BRIEFLY DESCRIBE THE CHANGES IN METHODOLOGY REGARDING USING HOURLY CLASS LOAD DATA IN THIS FORECAST UPDATE.

A. Developing the forecast based on hourly data provides several benefits. By starting with hourly load information to build the load forecast in this update, rather than

[1] Docket No. 19-06002, April 3, 2020, Modified Final Order at 68, para. 189.

monthly billing data, additional modifications to account for billing cycle differences are no longer necessary. Additionally, a separate peak forecast model is no longer required for the forecast model. Further detail on the steps included to adjust hourly information for the final sales and energy requirements are provided below and in Technical Appendix LF-1.

Next, using five years of hourly per-customer usage data for a particular forecast grouping, the average usage is determined for each month and a weekday/weekend categorization. These values are normalized to remove the impact of weather fluctuations from year to year. In this forecast update, the weather normalization process is based on distinct monthly coefficients, rather than an annual approach that was included in previous forecast updates. The process to derive these weather normalization adjustments is detailed below. The result is a typical-year, 8,760-hour load shape built for both weekdays and weekends average use for each customer group.

16. Q. BRIEFLY SUMMARIZE THE UPDATES MADE FOR THE JUNE 2023 ECONOMIC OUTLOOK.

A. The 2024 Joint IRP forecast uses an extrapolation of population series using the average of the annual growth rates obtained from S&P Global's IHS Markit forecast (released June 2023), the State Demographer's 20-year population projections (2022–2041), the State Demographer's 2022 Governor Certified Series, the University of Nevada, Las Vegas's Center for Business and Economic Research's ("CBER") long-term forecast (released May 2023), with minor adjustments to smooth forecasted growth. Additionally, hotel room projections based on the Las Vegas Convention and Visitors Authority ("LVCVA") executive summary are provided. See Technical Appendix LF-1 for further details on the model sales adjustments and development of the economic data provided in Technical Appendices LF-2 through LF-7. Table Pollard-Direct-2 summarizes the population forecast used to develop the 2024 Joint IRP forecast.

TABLE POLLARD-DIRECT-2
POPULATION USED IN FORECAST

	Population		
Year	NVE	Nevada Power	Sierra
2025	3,309,047	2,426,691	882,356
2026	3,351,046	2,461,402	889,644
2027	3,394,035	2,497,356	896,680
2028	3,432,554	2,529,378	903,176
2029	3,466,697	2,557,621	909,076
2030	3,497,290	2,582,511	914,778
2031	3,525,400	2,605,054	920,346
2032	3,551,843	2,625,978	925,865
2033	3,577,158	2,645,821	931,337
2034	3,602,081	2,665,348	936,733
2035	3,626,745	2,684,712	942,034
2036	3,651,305	2,704,101	947,204
2037	3,675,701	2,723,454	952,247
2038	3,699,999	2,742,803	957,196
2039	3,724,202	2,762,164	962,038
2040	3,748,263	2,781,496	966,767
2041	3,771,916	2,800,508	971,408
2042	3,795,072	2,819,064	976,008
2043	3,818,358	2,837,732	980,625
2044	3,841,789	2,856,524	985,265
CAGR			
2025-2027	0.8%	1.0%	0.5%
2025-2034	0.9%	0.9%	0.6%
2025-2044	0.7%	0.8%	0.6%

17. Q. HOW HAS THE FORECAST BEEN UPDATED FOR GROWTH IN NEM CUSTOMERS WHO CHOOSE TO INSTALL ROOFTOP SOLAR GENERATION?

A. For this 2024 Joint IRP forecast, NEM customers were separately considered from the full-requirements classes due to the strong recent growth in these customers over recent years. As of June 2023, approximately 102,250 individual residential customers had installed behind the meter on-site solar and wind facilities across NV Energy's service territories and are considered net-metering systems. Non-solar behind-the-meter accounted for a negligible fraction of total customer-generated energy, at approximately 0.15 percent of total Nevada NEM customers as of June 2023. Additionally, growth in non-solar customers has decreased, with no new customer after 2016 based on June 2023 information.

For the 2024 Joint IRP Forecast, NEM customer counts continue historical growth rate trends until the counts achieve 15 percent of the total residential customer population. At this point the customer growth rate coefficient is reduced by five percent per year, adjusted for population growth. At Nevada Power, the modelling results estimate approximately 989 residential customers install private generation per month until September 2027 when the growth rates begin to decrease. At Sierra, an additional 77 customers per month install generation and do not hit the limit through the forecast period.

In order to forecast the overall sales growth of solar customers, the average kW capacity of installed systems was used across all NEM customer classes. The average is approximately 7.4 kW for Nevada Power and 5.8 kW for Sierra residential customers. The NEM customer sales are derived by multiplying the forecasted counts by average use per NEM customer for monthly information, which is then refined for the weather normalization and SAE model adjustments. Projected incremental peak reductions of 25 MW at Nevada Power and 10 MW at Sierra by 2025 are based on the expected installed solar capacity of 942 MW and 71 MW for NEM rate class customers at each respective company.

Table Pollard-Direct-3 below details the customer growth and installed capacity for these customers included in the 2024 Joint IRP forecast. Further detail is provided in the IRP LF-1 Technical Appendix.

TABLE POLLARD-DIRECT-3
NEM CUSTOMER AND INSTALLED CAPACITY (MW)

	Nevada Power		Sierra	
Year	Customers	Capacity (MW)	Customers	Capacity (MW)
2025	123,254	941.7	11,719	71.3
2026	135,154	1,031.2	12,649	76.7
2027	147,036	1,120.6	13,579	82.2
2028	158,597	1,207.6	14,509	87.6
2029	169,750	1,291.6	15,438	93.1
2030	180,503	1,372.6	16,368	98.5
2031	190,868	1,450.8	17,298	103.9
2032	200,857	1,526.1	18,228	109.4
2033	210,476	1,598.7	19,158	114.8
2034	219,736	1,668.7	20,087	120.2
2035	228,650	1,736.0	21,017	125.7
2036	237,226	1,800.9	21,947	131.1
2037	245,477	1,863.4	22,877	136.5
2038	253,411	1,923.5	23,806	142.0
2039	261,041	1,981.4	24,736	147.4
2040	268,376	2,037.0	25,666	152.9
2041	275,426	2,090.6	26,596	158.3
2042	282,201	2,142.1	27,526	163.7
2043	288,710	2,191.7	28,455	169.2
2044	294,963	2,239.3	29,385	174.6

18. Q. HOW HAS THE FORECAST BEEN UPDATED FOR CHANGES IN FORECASTED ELECTRIC VEHICLE GROWTH?

A. The 2024 Joint IRP Forecast includes an electric vehicle forecast developed by a third-party consultant, E3, in October 2023 that was used as the basis to inform the Market Potential Study detailed in the "DSM" Plan. Further detail of how this forecast was developed is also provided in the Transportation Electrification plan.

The EV forecast assumes that EV adoption grows to account for 25 percent of total vehicles in Nevada by 2033. This represents EV adoption growth rates of 22 percent annually over the next 10 years. By 2044, the percentage of total vehicles increases to 44 percent. Incorporated into the sales growth are assumptions that the average EV is driven for 12,865 miles annually and that the "rated" efficiency for the average vehicle on the road today is 3.47 miles per kWh.

Additionally, E3's RESHAPE-EV model applies a derate to the vehicle's efficiency to capture the impacts of ambient temperature on the efficiency of the vehicle's battery and auxiliary energy use in the vehicle (e.g. use of the vehicle's air conditioning) while driving. Considering the impacts of ambient temperature, vehicles on the road today are assumed to drive 2.87 miles per 1 kWh of charging. This results in an average annual electric use per EV of 4,480 kWh. Further, this forecast assumes that battery efficiency will increase by one percent a year. The forecasted incremental loads are added to both the residential and commercial customer group forecasts based on the split modeled with RESHAPE-EV which showed 70 percent of charging will occur at home and 30 percent will occur at work or public charging stations. Further detail is provided in the IRP LF-1 Technical

Appendix, but Table Pollard-Direct-4 below details the change to the forecast from this input.

TABLE POLLARD DIRECT-4
CUMULATIVE EV GWH CHANGES

	2024 IRP			2021 IRPA 3rd			Change		
Year	Nevada Power	Sierra	Total	Nevada Power	Sierra	Total	Nevada Power	Sierra	Total
2025	440	214	653	172	57	229	268	156	425
2026	601	294	895	207	69	276	394	224	618
2027	785	383	1,168	241	80	322	544	303	846
2028	998	487	1,484	276	92	367	722	395	1,117
2029	1,227	597	1,824	311	104	415	916	493	1,409
2030	1,471	715	2,186	347	116	463	1,124	599	1,723
2031	1,710	829	2,539	385	128	513	1,325	701	2,026
2032	1,969	952	2,921	424	141	566	1,544	811	2,355
2033	2,111	1,020	3,131	463	154	618	1,648	865	2,513
2034	2,262	1,091	3,353	502	167	670	1,760	924	2,684
2035	2,415	1,163	3,578	541	180	721	1,874	983	2,857
2036	2,574	1,238	3,812	579	193	772	1,995	1,045	3,040
2037	2,717	1,305	4,022	617	206	822	2,101	1,100	3,200
2038	2,865	1,374	4,239	654	218	872	2,211	1,156	3,367
2039	3,015	1,444	4,459	691	230	922	2,323	1,213	3,537
2040	3,171	1,516	4,687	728	243	971	2,443	1,274	3,716
2041	3,307	1,579	4,886	765	255	1,020	2,542	1,324	3,866
2042	3,447	1,643	5,090	801	267	1,068	2,646	1,376	4,022
2043	3,585	1,707	5,292	837	279	1,116	2,749	1,428	4,177
2044	3,733	1,774	5,506	872	291	1,163	2,861	1,483	4,343

19. Q. WHAT UPDATES ARE INCLUDED IN THE 2024 JOINT IRP FORECAST FOR CHANGES TO THE FORECAST FROM DSM PROGRAMS?

A. This 2024 Joint IRP Forecast accounts for updates to the DSM programs, as of October 2023, that were provided by the Integrated Energy Services group. The amount of savings included in the base forecast are based on the current 1.1 percent of annual sales goals. Two incremental load forecast scenarios were created to include the proposed DSM savings as identified in the DSM Plan, and another that was increased 20 percent as a requirement from the most recently approved forecast in the 2021 IRPA Third Amendment order in Docket No. 22-09006. Further detail is provided in the IRP LF-1 Technical Appendix regarding the DSM savings reductions for the base load forecast, and the two additional load scenarios. Table Pollard Direct-5 below details the impact from these changes to DSM savings included in the base forecast.

TABLE POLLARD-DIRECT-5
DSM SALES REDUCTION (GWH) CHANGES

	2024 IRP			2021 IRPA 3rd			Change		
Year	Nevada Power	Sierra	Total	Nevada Power	Sierra	Total	Nevada Power	Sierra	Total
2025	1,380	3,447	4,828	944	450	1,394	436	2,998	3,434
2026	1,612	3,544	5,156	1,147	552	1,700	464	2,992	3,456
2027	1,854	3,644	5,498	1,351	657	2,008	503	2,986	3,489
2028	2,101	4,119	6,220	1,556	765	2,321	546	3,354	3,899
2029	2,356	4,837	7,193	1,762	875	2,637	594	3,962	4,556
2030	2,614	5,585	8,199	1,968	985	2,953	646	4,600	5,247
2031	2,866	6,342	9,208	2,174	1,096	3,269	692	5,246	5,939
2032	3,103	6,999	10,102	2,380	1,207	3,587	723	5,792	6,515
2033	3,202	7,533	10,735	2,587	1,318	3,905	615	6,215	6,830
2034	3,295	8,053	11,348	2,794	1,430	4,224	501	6,623	7,125
2035	3,390	8,569	11,959	3,002	1,542	4,544	388	7,027	7,415
2036	3,489	9,076	12,565	3,211	1,654	4,866	278	7,421	7,700
2037	3,589	9,516	13,105	3,421	1,767	5,188	168	7,749	7,917
2038	3,683	9,964	13,647	3,631	1,880	5,512	52	8,084	8,136
2039	3,779	10,410	14,189	3,842	1,994	5,836	(63)	8,416	8,353
2040	3,877	10,855	14,732	4,055	2,108	6,162	(178)	8,747	8,570
2041	3,974	11,293	15,267	4,268	2,222	6,489	(293)	9,071	8,778
2042	4,062	11,720	15,782	4,482	2,336	6,818	(420)	9,384	8,964
2043	4,148	12,136	16,284	4,697	2,451	7,148	(549)	9,686	9,136
2044	4,233	12,543	16,776	4,914	2,566	7,480	(681)	9,977	9,296

DR load adjustments previously included as load modifiers in the 2021 IRPA Third Forecast are now considered as a resource within the Loads & Resources table. Therefore, these programs have been removed from the load forecast presented here for the 2024 Joint IRP forecast. Further consideration of those programs are provided in the Demand Side Plan narrative.

20. Q. WHAT UPDATES WERE MADE TO FORECAST LARGE CUSTOMER ACTIVITY FOR THE 2024 JOINT IRP FORECAST?

A. The information developed for new or expanding individual Large C&I customers was a particularly intriguing, yet challenging, input in preparation of this forecast. NV Energy is forecasting an unprecedented amount of expected load growth over the next ten years. This growth is driven by strong economic conditions, which are described in more detail in Technical Appendix LF-7, that provides reports from Applied Analysis on the state of the Nevada economy. This is especially true for expected Large C&I customer growth in the Tahoe-Reno Industrial Center ("TRIC") area in Northern Nevada and the Apex area in Southern Nevada. As of August 2023, the period this component of the load forecast was finalized, there were 39 bundled-service projects that had requested approximately 7,600 MW of capacity additions, with nearly 6,500 MW at Sierra and 1,180 MW at Nevada Power, by 2033. Twelve of these projects are bundled-service high load factor data center projects who requested 5,900 MW of capacity and energy alone.

21. Q. ARE THESE PROJECTS AT DIFFERENT STAGES OF DEVELOPMENT?

A. Yes. Of the 39 projects, fourteen have signed customer Rule 9 agreements requesting 2,630 MW of bundled-service capacity at Sierra and 190 MW of capacity at Nevada Power by 2033. The remaining 25 projects are in the engineering study phase and have requested 4,800 MW of additional capacity, with 3,800 MW at Sierra and 990 MW at Nevada Power over the same period.

22. Q. HOW DOES THE FORECAST ACCOUNT FOR THESE DIFFERENT STAGES OF DEVELOPMENT?

A. Consistent with past practice, all of these requests are scaled down in the retail load forecast to account for potential delays and revisions to the customer provided forecasts. The inclusion of the study phase projects in this forecast requires additional adjustment, since historically only approximately 40 percent of study phase projects move forward. Therefore, the load levels for these projects included in this sales forecast were significantly reduced beyond that typically incorporated into the sales forecast for individual Major Projects who have signed Rule 9 agreements. The loads of projects in the study phase saw an average reduction of 85 percent before being included in the forecast; the loads of projects with signed Rule 9 agreements were reduced by 48 percent before being included in the forecast. This reduction lowers the overall impact of including these future projects into the base forecast for Commission consideration.

23. Q. HOW HAVE THESE PROJECTS PROGRESSED SINCE THE FORECAST WAS DEVELOPED?

A. The forecast is one of the earlier inputs in the preparation of this filing. Once provided and being used in the next steps of an IRP, the load forecast must remain the same and cannot reflect ongoing updates to these projects. While there have been several changes to the project list since these inputs to the 2024 Joint IRP forecast were finalized in August 2023, the current state of these projects in Nevada continue to support the overall load levels included in the 2024 Joint IRP forecast. Since these inputs were finalized, zero projects with signed Rule 9 agreements have been cancelled, five study phase projects have moved out of the study phase and into signed agreements, three other projects in the study phase have been put on hold, and there are four additional study phase projects that would now be included for consideration.

24. Q. WHAT WOULD THE EXPECTED MAJOR PROJECTS LOAD LEVELS BE IN THIS FORECAST IF UPDATED INFORMATION WAS CONSIDERED?

A. If updated Major Project information were included in the 2024 Joint IRP forecast it would be expected that the overall load levels would in fact be higher than those included in the Companies' base load forecast.

The net effect of any updates; removing the study phase projects placed on hold, adding new projects, and modifying the expected loads of those projects with now-signed agreements, would provide an overall 2,304 MW increase in the amount of requested capacity for signed Rule 9 agreement projects at the expense of a 2,605 MW decrease of Study phase projects, for a net decrease of 301 MW of requested capacity. However, applying a consistent approach to the mitigation of these requested amounts, as that included in the base forecast, results in a net increase of approximately 800 MW of expected loads by 2033, because the incremental signed agreement project amounts are discounted by a lower percentage than those currently in the study phase.

While the status of these projects will continue to change over time, the Companies' incorporation of the expected loads for upcoming Major Projects that are included in the load forecast represents a reasonable result that the Commission should find suitable for making long-term planning decisions within this proceeding.

25. Q. HOW DOES THE 2024 JOINT IRP FORECAST INCORPORATE CUSTOMER IMPACTS TO RETAIL PRICES OVER THE FORECAST PERIOD?

A. In the 2024 Joint IRP Forecast, the Retail Price component was specifically excluded from the SAE modelling efforts so that the results could be individually presented. In an effort to respond to the Commission requirement for more detailed rate impact analyses in recent amendments, the update for the 2024 Joint IRP Forecast calculates the estimated load impact stemming from changes in price separately. The forecasted rates, detailed in the Financial Plan are used to estimate the potential impacts on the load forecast. Overall, the impact is small in that the forecasted rates estimate a reduction of 60 GWh (average 6.8 MW) by 2044. The steps for this analysis and resulting impacts are further detailed in Technical Appendix LF-1.

26. Q. HAVE HIGH AND LOW LOAD FORECAST SCENARIOS BEEN DEVELOPED FOR THIS FORECAST?

A. Yes. High and low load forecasts were produced based on optimistic and pessimistic economic, demographic and large customer growth assumptions. *See* Technical Appendix LF-1 for more details regarding the development of the high and low load forecast scenarios.

27. Q. WHAT IS YOUR OVERALL VIEW OF THESE UPDATES TO THE 2024 JOINT IRP FORECAST?

A. Overall, the Companies' 2024 Joint IRP proposal provides reasonable updates to the 2021 IRPA Third Amendment forecast previously accepted in the stipulation by the Commission in Docket No. 22-09006. This updated forecast is based on substantially accurate data, is documented appropriately, and has been adequately explained and defended. The updates to the overall forecast are thus a reasonable basis upon which to make long-term planning decisions for the 2025–2044 planning horizon.

III. 704B RATE CALCULATIONS

28. Q. PLEASE BRIEFLY SUMMARIZE SB547 AND THE IMPLEMENTING REGULATION.

A. The adopted regulation in Docket No. 19-06029 provides an avenue for current bundled service customers of the Companies, with annual loads over an average of 1 megawatt ("MW"), to exit bundled service and purchase energy from another provider. In an effort to support a long-term approach to customers who may choose to exit bundled service, while limiting negative impacts on system costs and ensuring remaining customers are not harmed, Senate Bill 547 (2019) and the implementing regulation adopt a number of mechanisms. Key among these mechanisms are limitations on the amount of annual load that can leave bundled service during an action plan period and an obligation to pay bundled charges during the three-year period following an eligible customer's departure.

Subsection 6 of NRS 704.741 lists the factors that must be considered in determining the annual limits eligible to leave bundled service; however, per the regulation, these annual limits are not to exceed 50 percent of the large commercial and industrial ("Large C&I") forecasted load growth during the three-year action period. In accordance with subsections 6 and 7 of NRS 704B.310, as part of limiting any negative impacts on the system or to remaining customers, eligible customers must pay their fully bundled general rates and any applicable rates and charges, as approved by the Commission, for a three-year period following the date of the customer exiting bundled service.[2]

After the three-year period, these customers will pay the applicable Open Access Transmission Tariff ("OATT"), Distribution Only Service ("DOS"), and any additional rates from NV Energy, as ordered by the Commission, in addition to those charged by their new provider.

29. Q. HOW ARE THE ANNUAL LIMITS FOR THE ACTION PLAN PERIOD DETERMINED?

A. Following the methodology approved in the 2021 Joint IRP, the Large C&I year-end sales growth over the three-year action plan period, January 1, 2025, through December 31, 2027, is calculated as the difference in the year-end sales for 2027 minus the three-year average of actual annual Large C&I loads during the 2021–2023 period. Thus, the difference between the load at the end of 2027 yields the action plan period load growth under normal economic conditions.

In addition to this base year load calculation for Nevada Power, loads for individual customers on tariff schedules with non-standard, fully-bundled price options (e.g. GS-4 New Generation – GS-4-NG, Large Customer Market Price Energy – LCMPE, Market Price Energy – MPE, or the Economic Development Rate Rider – EDRR tariffs) were excluded from the load growth calculations for both utilities. The adjusted difference in load is then reduced by 50 percent to reflect the requirement that the eligible loads are offset by future expected growth in Large C&I customer sales.

[2] These customers will pay FERC transmission and OATT charges once they leave bundled service but will receive a credit for these charges on their bundled rate bill during their three-year exit period.

30. Q. WHAT ARE THE LOAD LEVELS ELIGIBLE TO LEAVE BUNDLED SERVICE UNDER 704B FOR THE CURRENT THREE-YEAR ACTION PLAN PERIOD?

A. As detailed in Section 6 of the Load Forecast Narrative and Section VI of the Load Forecast Technical Appendix LF-1, the proposed eligible loads, which represent annual limits for the entire action plan period and summarized below in Table Pollard-Direct-6, are 260,662 MWh for Nevada Power. Due to the lack of import capacity at Sierra the limit has been set to zero MWh in this proceeding. The required non-load growth factors that determine the eligible annual limits, as identified in both NRS 704.71(6) and the regulation (i.e. import capacity, system constraints, and the effect of eligible customers purchasing less energy and capacity than authorized by the proposed annual limit), were considered for both regions, but only have an impact on the proposed limits for Sierra (lack of import capacity).

TABLE POLLARD-DIRECT-6
704B ELIGIBLE LOADS

	2025	2026	2027
Nevada Power			
Total Annual MWh Sales	22,627,431	23,078,478	23,531,685
Eligible Annual Limit MWh Loads	86,887	86,887	86,887
Modified Sales	22,540,544	22,991,591	23,444,798
Annual MW Peak	6,630	6,631	6,717
Coincident MW Peak of Eligible Loads	29.8	29.8	29.8
Modified MW Peak	6,600	6,601	6,687
Sierra			
Total Annual MWh Sales	11,068,156	12,024,181	12,881,888
Eligible Annual Limit MWh Loads	-	-	-
Modified Sales	11,068,156	12,024,181	12,881,888
Annual MW Peak	2,353	2,374	2,487
Coincident MW Peak of Eligible Loads	-	-	-
Modified MW Peak	2,353	2,374	2,487

31. Q. WHY ARE CUSTOMERS UNDER SPECIAL TARIFFS NOT INCLUDED IN THE CALCULATIONS OF THE MAXIMUM ANNUAL LIMITS?

A. The customers on these various tariffs with different pricing options do not contribute the same revenue per kilowatt-hour ("kWh") as other bundled customers. For example, a large casino and data center customer who pay contracted rates pursuant to the MPE and LCMPE tariffs, do not pay the standard bundled-service costs of generation but rather through an Energy Service Agreement, and are therefore excluded from the calculations at Nevada Power. These customers contribute zero towards the generation costs of the system as they are not relying on the Companies' internal generation embedded in revenue requirement. Therefore, to ensure that the revenue associated with any exiting loads is offset only by the revenue from any load growth paying traditional bundled rates, it is appropriate to exclude these customers from the calculations.

32. Q. WHAT ADDITIONAL CONSIDERATIONS ARE INCLUDED IN THE DETERMINATION OF LOADS ELIGIBLE TO EXIT BUNDLED SERVICE?

A. In addition to considerations of loads to be included in the calculations of sales eligible to leave bundled service, several additional items identified in NRS 704.741(6) and the pending regulation are included, such as "import capacity, system constraints, and the effect of eligible customers purchasing less energy and capacity than authorized by the proposed annual limit."

33. Q. WERE ANY OF THESE ADDITIONAL CONSIDERATIONS INCORPORATED IN THIS PROCEEDING?

A. Yes, as required by NRS 704.741(6) and the regulation, all of these determinants were considered, as reflected in the Load Forecast narrative. The primary limiting adjustment is that there are currently import capacity constraints at Sierra, where more than 681 MW of transmission capacity reservations are waiting to be initiated on the system. These transmission constraints prevent any loads from being able to import energy from another provider outside of Sierra's system during the 2025-2027 period. Sierra is not projected to satisfy this outstanding import capacity need during the action plan period. Greenlink West increases Sierra's import capacity by 725 MW into Northern Nevada, of which 44 MW will be allocated to Sierra's existing 623 MW native load capacity requirements after the 681 MW of network customer reservations are met. In 2029, Greenlink North increases Sierra's import capacity by an additional 800 MW and will provide the remaining 579 MW for native load capacity. The remaining 221 MW will be allocated to native load requirements in 2032. Thus, due to the current import capacity constraints, analysis of this factor places the annual limits for Sierra, for the action plan period at zero MW. Nevada Power's available import capacity is 3,214 MW. In light of this ample open import capacity, NV Energy does not propose to impose any limits on the amount of energy and capacity available to eligible 704B applicants on account of import capacity restrictions for Nevada Power.

34. Q. WHAT FEES WILL EXITING CUSTOMERS PAY TO ENSURE THAT OTHER CUSTOMERS ARE HELD HARMLESS?

A. To meet NRS 704B.310 public interest requirement, the regulation includes the provisions that these customers will continue to pay the equivalent of the fully bundled Base Tariff General Rates ("BTGR") for a three-year transition period, and a rate for the Base Tariff Energy Rate net of out-of-the-money power purchase agreements costs ("Net Differential Energy Rate") for a three-year period. In addition, the incremental Renewable BTER ("R-BTER") rate and other public policy program rates shall be included on an ongoing basis for these customers' bills. Further, any applicable additional costs related to Decommissioning and Remediation costs and Regulatory Asset charges must be imposed by the Commission on customers choosing to exit bundled service to begin taking service from a third-party energy provider.

35. Q. WHAT ARE THE PROPOSED ENERGY RELATED CHARGES PROPOSED IN THIS PROCEEDING?

A. Pursuant to subsection 1 of Section 2 of the implementing regulation, Net Differential Energy Rate and the credit/charge for variable operations and maintenance (“O&M”) costs is determined in a triennial resource plan and is held constant for the duration of the corresponding three-year transition period.

The results of the calculations demonstrate that Nevada Power customers choosing to exit the system will pay the Net Deferential Energy Rate of $0.04165 per kWh during their applicable three-year transition period which will be partially offset by the $-0.00015 per kWh variable O&M costs credit. In addition, such customers will pay other costs required by law including the Base Tariff Energy Rate for the transmission period and the then-current R-BTER rate (which currently stands at $0.00404 as filed in Docket No. 24-05014) and will be updated quarterly.

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

A. Yes.

EXHIBIT POLLARD-DIRECT-1

TIM POLLARD
DIRECTOR-LOAD FORECASTING, RESEARCH & ANALYTICS
RATES & REGULATORY AFFAIRS
NV Energy
6100 Neil Road
Reno, Nevada 89511-1137
(775) 834-4006

Mr. Pollard has been an employee of NV Energy since 2007 and is currently the Director of Load Forecasting, Research and Analytics. His responsibilities are focused upon leading the load research and forecasting teams for regulatory filings and special assignments in support of the Rates & Regulatory Affairs department's responsibilities.

Prior to joining the company in his current position, Mr. Pollard had experience across different industries and was most recently employed at Covance Cardiac Safety Services, a clinical research organization for the pharmaceutical industry, as a Senior Clinical Data Manager.

Employment History
NV Energy

Director-Load Forecasting, Research & Analytics
Technical Lead, Regulatory Policy, Strategy & Analysis
Pricing Specialist, Regulatory Pricing & Economic Analysis
Staff Economist, Regulatory Pricing & Economic Analysis
Senior Economist, Regulatory Pricing & Economic Analysis
January 2007 to Present

- Leads load forecasting and load research teams for required strategy and regulatory activities
- Supports load research and forecasting results as necessary in regulatory filings
- Guides technical aspects of cost of service and rate design filings and special assignments
- Conducts research and prepares studies for internal and external presentation
- Provides technical support and analyzes data necessary to resolve the complex set of pricing, financial, economic, and regulatory issues for filings in Nevada and California, Gas and Electric case filings
- Applies extensive experience and understanding of the principles and theories of cost of service and rate design as well as the technical mechanics and applications necessary to successfully develop pricing of electric and gas service
- Provides direction and technical assistance to less experienced team members
- Develops educational materials and actively instructs other team members on various technical, economic and cost of service related subjects

Economist, Resource Planning & Analysis
June 2004 to December 2004

- Conduct research and prepare studies for internal and external presentation
- Prepare and assist in preparation of load forecasts
- Assist in technical aspects of market analysis projects as requested

Non-Sierra Employment

Covance Cardiac Safety Services
January 2005 to January 2007

Senior Clinical Data Manager (10/06 to 1/07)**; Clinical Data Manager** (2/06 to 10/06)**; Data Analyst** (1/05 to 2/06)**, Data Management & Statistics**

- Technical Lead for all department activities within business unit for the development/validation of new systems and processes
- Acted as primary liaison and escalation contact for clients assigned within team to ensure that data presented met or exceeded the agreed upon expectations for accuracy and timeliness
- Developed and implemented internal and external reports, processes and metrics to add value to company through data analysis, management and quality control activities
- Accountable for all department personnel and activities within Clinical Trial Operations Team

Nevada State Health Division
December 2000 to June 2004

Health Resource Analyst II (7/02 to 6/04)**; Health Resource Analyst I** (12/00 to 7/02)**, Center for Health Data and Research, Bureau of Health Planning & Statistics**

- Development, linkage, management, and analysis of Public Health Data Warehouse (Cancer Registry, HIV/AIDS, Vital Statistics) for program policy and reporting issues relating to public health arena
- Prepared statistical and special topic reports, performed quality assurance measures and evaluated other health related program data
- Management, quality assurance and analysis of Vital Statistics databases for various Division programs, state agencies and requests from the public for health statistics

Education

University of Nevada, Reno
Bachelor of Arts in Economics, August 2000

Certifications

SAS Certified Advanced Programmer
SAS Certified Basic Programmer

Prior Testimony before Public Utilities Commissions

PUCN Dockets: 07-12001, 08-12002, 08-10043, 09-06029, 10-06001, 10-07003, 11-06006, 13-06002, 15-07041, 15-07042, 16-06006, 16-06007, 18-11039, 19-06002, 20-06003, 21-10012, 22-06014, 22-09006, 23-06007, 23-08015, 24-02026, and 24-02027.
CPUC Applications: 08-08-004.

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, 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: May 31, 2024

TIMOTHY POLLARD

ZELIJKO VUKANOVIC

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05___

Prepared Direct Testimony of

Zeljko Vukanovic

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

A. My name is Zeljko Vukanovic. I am the Market Fundamentals Lead 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" or "NV Energy"). My business address is 6226 West Sahara Avenue, Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

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

A. I hold a Master of Science degree in Finance and Banking from Boston University and Master of Business Administration degree from the University of Nevada, Las Vegas. I have been employed by the Companies since June 2006 and have served as the Market Fundamentals Lead since September 2019. Prior to my current role, I served in Resource Planning and Analysis as Valuation Specialist, where I performed Energy Supply Plan analyses. I have also held the Consultant Staff position in the Demand

Side Management department at NV Energy. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Vukanovic-Direct-1**.

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

A. Yes, I have testified before the Commission in Docket Nos. 12-06051, 13-07002, 13-07005, 14-07007, 14-07008, 21-06001, 22-03024, 22-09001, and 23-0815.

4. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am sponsoring the wholesale power and natural gas price forecasts ("Price Forecasts") that are presented in Section 4 of the narrative to the Companies' 2024 Joint Integrated Resource Plan ("2024 Joint IRP"). I also sponsor the following Technical Appendix item, which is confidential:

- Section 2, Market Fundamentals, co-sponsor with Ryan Atkin
- Section 3, FPP-1 - Fuel and Purchased Power Price Forecasts

5. Q. ARE ANY OF THE MATERIALS YOU ARE SPONSORING CONFIDENTIAL?

A. Yes. In addition to Technical Appendix FPP-1, other portions of this filing that I sponsor contain commercially sensitive and/or trade secret information that derives independent economic value from not being generally known and are derived by proprietary information of third parties. The confidential materials include price forecast charts that are presented in the following figures from the Fuel and Purchased Power ("F&PP") Price Forecasts narrative:

- Figure PF-2 – Annual Gas Price Forecast
- Figure PF-3 – Annual Market Implied Heat Rate Forecast
- Figure PF-4 – Average Annual Power Price Forecast
- Figures PF-5 and PF-6 – Base, High and Low Gas Price Forecast
- Figure PF-7 – Base, High and Low Power Price Forecast
- Figure PF-8 – Projected Capacity Prices

This confidential information is obtained from Argus Media Inc. ("Argus"), a leading provider of data on commodity prices, and Wood Mackenzie ("WoodMac"), a fee subscription service and recognized provider and consultant for the energy industry and cannot be publicly disclosed. This information is protected by confidential provisions between the Companies and Argus and WoodMac and contains essential qualitative descriptions of the assumptions and methodologies used to develop the price projections.

Similarly, the Companies purchase and sell energy and capacity in the wholesale market. In seeking or responding to requests for proposal ("RFPs"), the confidentiality of the Companies' price forecasts is key to the competitive process. Therefore, it is fundamentally contrary to the interests of customers to provide public access to Companies' confidential price forecasts for market energy and fuels.

6. Q. **REGARDING THE MATERIALS IDENTIFIED AS BEING CONFIDENTIAL IN Q&A 4 AND Q&A 5, FOR HOW LONG DO THE COMPANIES REQUEST CONFIDENTIAL TREATMENT?**

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

7. 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 FULLY INVESTIGATE THE INTEGRATED RESOURCE PLAN?**

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

8. Q. **WHAT EXHIBITS ARE ATTACHED TO YOUR TESTIMONY?**

A. I have attached the following exhibit to my testimony:

Exhibit Vukanovic-Direct 1 - Statement of Qualifications

9. Q. **PLEASE BRIEFLY DESCRIBE THE NATURAL GAS AND PURCHASE POWER PRICE FORECASTS USED IN THIS PROCEEDING.**

A. The base, high and low fuel and purchased power price forecasts used in this filing have been prepared in a manner consistent with previous integrated resource plan ("IRP") filings made by the Companies. The methodology used to prepare the Price Forecasts relies upon near-term observable market-based price quotes that are blended into a long-term market fundamental price forecast. These Price Forecasts are described in Section 4 of the 2024 Joint IRP.

10. Q. PLEASE DESCRIBE THE DATA SOURCES USED FOR THE MARKET-BASED PRICE QUOTES AND MARKET FUNDAMENTAL PRICE FORECAST YOU DESCRIBE IN Q&A 9.

A. The source of data for natural gas quotes is Argus.[1] These quotes reflect observed transactions at the following natural gas trading hubs: Henry Hub, Alberta NOVA Inventory Transfer ("AB-NIT" or "AECO"), Sumas, Northwest Pipeline Rockies ("Rockies"), Malin, and the Southern California Border ("SoCal"). Similarly, quotes for purchased power are obtained from Argus and reflect observed transactions at power trading hubs Mead, and Palo Verde.

The long-term fundamental price forecast is obtained from WoodMac, which publishes its fundamental price forecast (Long-term outlook or "LTO") bi-annually. The price curves in this filing are based on the "Policy Headwinds Update" case released by WoodMac in July of 2022. WoodMac performs detailed modeling of regional natural gas and power markets, taking into account supply-demand price dynamics. The market fundamentals in this case serve as the foundation in building the price forecasts included as Technical Appendix Item FPP-1.

[1] Argus is a leading provider of data on commodity prices and is widely relied upon for indexation of physical trade.

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

11. Q. **PLEASE DESCRIBE THE PROCESS USED TO PREPARE THE NATURAL GAS AND POWER PRICE FORECASTS.**

A. All resource plan alternatives were evaluated against a base case natural gas price forecast assuming an adjustment to the Henry Hub price due to the expected effects associated with implementation of the U.S. Inflation Reduction Act ("IRA"). NERA Economic Consulting ("NERA") developed projected impacts to the Henry Hub natural gas price. The near-term (January 2025 through March 2027) market quotes for power and gas are based entirely on the average of settlement prices during 20 trading days in December 2023. The Price Forecasts transition from being entirely market-based price quotes to entirely long-term fundamental forecast during a 24-month blending period from April 2027 through March 2029. The near-term market-based quotes are incrementally blended with the long-term fundamental forecast across this transition period.[2] The Companies used the pure fundamental forecast for the April 2029 through December 2050 portion of the price forecast. Thus, the near-term market quotes, blending period, long-term forecast, and the escalation period constitute the forecasted natural gas price curve for each of the relevant Western natural gas trading hubs. The natural gas price forecasts are provided in Technical Appendix FPP-1.

Power prices are derived by multiplying the forecasted gas prices and the forecasted market implied heat rate ("MIHR") defined as the ratio of power prices and the corresponding gas price for that market. The MIHR

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[2] The blending of market quotes and the fundamental forecast occurs across four gas seasons, or 24 months, with a weighting of the fundamental forecast increasing monthly by 4.0 percent per month.

forecast for January 2025 through March 2027 is the ratio of 20-day average power price quotes from Argus and the 20-day average forward gas prices from Argus, as described above. The second part of the curve, from April 2027 to March 2029, reflects a blend of market heat rates based on the market quotes and fundamental forecast. In the blending process, the MIHR based on pure market quotes are more heavily weighted in the initial period, with the MIHR based on the fundamental portion of the curve receiving greater weight towards the end of the blending period. The third part of the curve, from April 2029 until December 2050, is entirely based on the MIHR curve from the fundamental forecast. The power price forecasts are also provided in Technical Appendix FPP-1.

12. Q. HOW DID THE COMPANIES CONSTRUCT THE HIGH AND LOW FUEL AND PURCHASE POWER PRICE FORECASTS?

A. The Companies include sensitivity analyses around the base case projections to determine how planning results vary under a range of market price conditions. High- and low-price curves for natural gas were calculated at one standard deviation around the base case forecast (plus and minus). High- and low-power price forecasts were prepared to reflect Western energy prices that fluctuate with the respective natural gas price forecasts, using the heat rate of a typical combined-cycle unit. The profit margin (or spark spread) reflected in the base case price forecast was added to both the higher and lower computed energy prices. The spark spread is calculated as a dollar per megawatt-hour value.

13. Q. **DID THE COMPANIES CONSIDER THE IMPACT ON FUEL AND PURCHASE POWER PRICES FROM FUTURE CARBON POLICY AND CHANGE FROM THE APPROACH PROVIDED IN PREVIOUS IRP FILINGS?**

A. Yes, the Companies have developed Low, Mid, and High Carbon Price Forecasts based on NERA input. NERA considers it appropriate to assume that federal climate policy affecting fossil fuel prices will be based on the Inflation Reduction Act ("IRA") and to evaluate the resulting effects on fossil fuel prices. The Price Forecasts for the carbon price scenarios are in Technical Appendix FPP-1. The sensitivity cases evaluating the impact to fuel and purchased power costs are described in the Economic Analysis section sponsored by. Kimberly Williams.

14. Q. **PLEASE DESCRIBE THE IMPACT OF CARBON POLICY ON FUEL PRICES.**

A. NERA developed assessments of price impacts to natural gas resulting from changes in natural gas demand due to the IRA provisions based upon this existing modeling information. The effects of Low, Mid and High carbon price adjustors on fossil fuels are stated as annual percentage adjustments to wholesale fossil fuel prices. More information regarding the carbon power price adjustors can be found in Section 4 of the narrative. Details regarding development of the fuel price adjustors are sponsored by Dr. David Harrison of NERA.

15. Q. **HOW DO YOU CAPTURE CAPACITY COSTS FOR PURPOSES OF THE POWER PRICE FORECAST?**

A. WoodMac's regional power price forecast represents day-ahead firm energy prices, however, it does not explicitly include the full cost of new capacity additions that would be required to ensure resource adequacy over the forecast period. Therefore, the WoodMac also prepares a capacity price forecast for market purchases to supplement the regional power price forecast. The regional price forecast is used by the PLEXOS model to economically dispatch market purchases against internal generation, while the capacity price forecast (dollars per kilowatt-year) is multiplied by the Companies' open capacity position as an additional fixed fuel and purchased power cost.

16. Q. HOW DID THE COMPANIES PREPARE THEIR LONG-TERM CAPACITY PRICE FORECAST?

A. As part of its long term outlook ("LTO"), WoodMac prepared an estimate of the levelized cost of new entry ("CONE") for the installed cost of future generation. The CONE is an estimate of the annual fixed costs associated with owning and operating a new generating facility (i.e., exclusive of variable costs such as fuel and emissions). The CONE was used to compute a long-term capacity price forecast. Annual capacity prices (in dollars per kW-year) were calculated as the difference between the CONE and the net energy margins reflected in the wholesale power price forecast (i.e., spark spreads).

17. Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

EXHIBIT VUKANOVIC-DIRECT-1

Statement of Qualifications

Zeljko "Zack" Vukanovic

Professional Experience

2019 To Date **Market Fundamentals Lead, Resource Planning and Analysis**
NV Energy

Developes and maintaines proprietary perspective on regional gas and power market factors and fundamental price forecasts.

2017-2019 **Valuation and Planning Specialist, Resource Planning and Analysis**
NV Energy

Used market fundamentals analysis to resolve complex pricing, financial, economic, regulatory or legislative issues.

2012-2017 **Staff Consultant, DSM Planning**
NV Energy

Project Manager for Demand Side Management ("DSM") portion of Integrated Resource Plan ("IRP"), DSM Electric and Gas Annual Update Reports, and DSM portion of Renewable Portfolio Standard ("RPS") Annual Report.

2010-2012 **Senior Consultant, DSM Planning**
NV Energy

Responsible for optimizing the portfolio of DSM electric and gas programs with a goal of maximizing customer and shareholders benefits.

2006-2010 **Consultant, DSM Planning**
NV Energy

Responsible for quantitative and qualitative program evaluations with a goal of developing sustainable and cost effective DSM programs.

Education

Master of Science in Banking and Finance at the Boston University, 2011

Master of Business Administration at the University of Nevada at Las Vegas, 2008

Bachelor of Science in Business Administration, Megatrend University in Belgrade, Serbia, 2003

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, ZELJKO VUKANOVIC, 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: May 31, 2024

ZELJKO VUKANOVIC

VINCENT VITIELLO

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05___

Prepared Direct Testimony of

Vincent Vitiello

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

A. My name is Vincent Vitiello. I am the Gas Supply Planning Lead 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" or "NV Energy"). My business address is 6226 West Sahara Avenue, Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

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

A. My professional experience includes more than 30 years in the utility and power generation industries. I have a Bachelor of Engineering degree with a concentration in mechanical engineering and have worked for the Companies since 2006.

Prior to joining the Companies, I was employed for six years by Chevron Corporation ("Chevron") as the Assistant Executive Director at Nevada Cogeneration Associates #1 and Nevada Cogeneration Associates #2. Prior to that, I worked at Southwest Gas Corporation ("SWG") for 14 years, in the major accounts and engineering departments. Prior to that, my first career position was as an engineer at Exxon Company, U.S.A., in the refining and oil and natural gas production areas. More details regarding my background and experience are provided in **Exhibit Vitiello-Direct-1.**

3. Q. WHAT ARE YOUR RESPONSIBILITIES AS GAS SUPPLY PLANNING LEAD?

A. As the Gas Supply Planning Lead, I am primarily responsible for the short and long-term planning of the Companies' natural gas transportation and storage assets necessary to ensure the adequate supply of natural gas to the Companies' generation plants and to Sierra's gas distribution system. I am also responsible for reviewing and monitoring pipeline filings, negotiating rate case settlements, and supporting related efforts before the Federal Energy Regulatory Commission ("FERC") and state regulatory commissions.

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

A. Yes, I provided testimony before this Commission in Docket Nos. 23-03005, 23-03006, 23-03007 and 23-09003.

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

A. In my testimony, I sponsor the Fuel Supply portion of the Supply Plan section that addresses the gas transportation outlook and strategies.

6. Q. **PLEASE SUMMARIZE THE COMPANIES' NATURAL GAS TRANSPORTATION STRATEGY.**

A. Section C of the Supply Plan, Fuel Supply, summarizes the Companies' gas transportation strategies. The Companies are not proposing to add to their existing gas transport portfolio.

The TC Energy Foothills contracts will automatically renew and extend to October 31, 2025. Northwest Pipeline contract 10061 automatically renewed in March 2024 and contract 10046 will automatically renew in June 2024.

While Nevada Power is short on natural gas transportation during certain periods, it will continue to rely on delivered gas to reliably meet its open positions. Nevada Power is seeking approval to maintain its current natural gas transportation portfolio. Nevada Power's daily gas usage requirements during July and August exceed the current contracted capacity with Kern River. Nevada Power has adequately closed prior firm gas transportation open positions by purchasing delivered natural gas and proposes to continue this strategy. Nevada Power will continue to evaluate whether there is a need to acquire new firm transportation capacity and may revisit this strategy in a future filing. Alternatively, the Companies may evaluate the possibility of deviating from an approved ESP or ESP update "to the extent necessary to respond adequately to any significant change in circumstances not contemplated by the energy supply plan" pursuant to NAC § 704.9504, should conditions warrant such an action.

7. Q. HAVE ANY INTERSTATE PIPELINE RATE CASES CONCLUDED OR INITIATED SINCE THE LAST ESP?

A. The Gas Transmission Northwest ("GTN") Pipeline, owned by TC Energy, filed a rate case at FERC on September 29, 2023. GTN began pre-hearing settlement discussions, which Sierra participated in. A settlement has not yet been reached. Sierra will continue with pre-hearing settlement discussions and participate in and monitor this rate case. GTN began pre-hearing settlement discussions on May 10, 2023, which Sierra participated in. A settlement has not yet been reached. Sierra will continue with settlement discussions and participate in and monitor this rate case if filed.

Great Basin Gas Transmission filed a rate case at FERC on March 6, 2024. Sierra will be participating in and monitoring this case closely.

8. Q. DID THE COMPANIES EVALUATE THE ADEQUACY OF THE CURRENT FIRM INTERSTATE GAS TRANSPORTATION CONTRACTS TO ENSURE SUFFICIENT NATURAL GAS SUPPLY TO THE COMPANIES' GENERATION FLEET, ALONG WITH SIERRA'S NATURAL GAS LOCAL DISTRIBUTION COMPANY ("LDC")?

A. Yes. For Nevada Power, PLEXOS was used to further evaluate projected firm gas transportation needs for the generation fleet. The time-period of the analysis was January 2025 through December 2027. One Nevada Transmission Line ("ON Line") was assumed to be in service for these analyses.

Nevada Power: The following two scenarios were evaluated: 1) normal weather conditions with existing firm gas transportation contracts; and 2) hot summer/cold winter weather conditions (based on 1 in 10 peak cooling-degree-day and heating degree-day) and existing firm gas transportation contracts. Historically, Nevada Power's firm interstate gas transportation open positions have been reliably met by purchasing firm delivered gas. Nevada Power will continue to purchase firm delivered gas to close any open gas transportation positions during the action plan period. Further details of the Nevada Power analysis can be found in section 2.E of the Energy Supply Plan.

Sierra: PLEXOS was used to evaluate the system reliability and projected firm gas transportation needs for both the plants and LDC with ON Line in service. PLEXOS was used to estimate system reliability, as quantified by loss of load hours ("LOLH") for both Nevada Power and Sierra, with the latter combining electric and LDC needs.

LDC natural gas requirements were prioritized ahead of electric generation requirements for three reasons: (1) human safety, (2) no alternative fuels, (3) and the significant cost of a re-light. For the LDC, the analysis period was limited to December and January (for the years 2025-2027), as the LDC's recorded peaks have predominantly occurred in those two months. Sierra evaluated the following three scenarios: 1) normal weather conditions and existing natural gas transportation contracts; 2) cold winter weather conditions (based on 1 in 10 peak heating-degree-day) and existing natural gas contracts; and 3) extreme weather conditions (based on 70 heating-degree-days). The key finding from this analysis is that Sierra has enough firm transportation/storage resources under contract to meet the average daily gas supply required on a winter day under normal weather conditions, so long as generation is available from the southern system via the ON

Line. Sierra also has enough gas transport capacity for the cold winter (1 in 10) scenario average day with the LDC peak day approximately 75 percent of the gas transport capacity. During an extreme winter weather scenario, the LDC peak day requirements are forecasted to exceed the firm gas transport capacity, rending Sierra's natural gas-fired generation plants unavailable.[1] In the extreme weather case, the electric requirements would need to be met with a combination of purchase power, renewable energy, and inter-company exchange from the southern system.

Sierra's analysis demonstrates that it has adequate gas transportation capacity and should maintain that capacity. Adding additional capacity would mitigate a remote loss of load risk but would increase costs. However, reducing capacity would increase the risk of loss of load in the winter to a level that is unacceptable. Further details of the Sierra analysis can be found in Section 2.E of the Energy Supply Plan.

9. Q. PLEASE DESCRIBE THE RESULTS OF PRODUCTION COST MODELING AND EXPLAIN WHY THE COMPANIES ARE NOT MODIFYING THE GAS TRANSPORTATION PLAN.

A. Both Nevada Power and Sierra need to have natural gas delivered to generation power plants, but Sierra also must serve its LDC customers. The PLEXOS analysis shows under normal weather conditions, Nevada Power has a shortage of gas transportation capacity to deliver all of the gas volumes needed for the operation of the gas generating units, while Sierra has an adequate amount of capacity to fulfill the needs of both the generating units and LDC. The gas transportation contracts

[1] It is noteworthy that the Valmy power plants, being converted from coal to natural gas for 2026, because of their location, do not compete for natural gas with Sierra's local gas distribution system.

are critical to system reliability and it is important to maintain the Companies' contracted capacity to serve future loads.

Nevada Power: Nevada Power's projected gas requirement under normal and extreme weather conditions shows an open position with respect to interstate gas transportation; however, Nevada Power continues to be able to purchase delivered gas (i.e., gas supply plus transportation), to reliably meet the open positions with respect to interstate gas transportation. It should be noted that delivered gas is subject to the availability of willing counterparties and carries some market pricing and availability risk. Nevada Power will continue to evaluate the need for additional transportation capacity.

Sierra: Sierra's projected gas requirement under extreme weather conditions maximizes the use of all its firm transportation capacity. Failure to renew the gas transportation contracts that are up for renewal in the planning period would place Sierra's customers at greater risk of a curtailment to the LDC due to a lack of gas supply, which would result in a very high consequence event. Furthermore, by not renewing the contracts, Sierra would lose the option of securing the contracts in subsequent years, and thus, risk losing future access to the pipelines.

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

A. Yes.

EXHIBIT VITIELLO-DIRECT-1

Vincent J. Vitiello
6226 West Sahara Avenue
Las Vegas, Nevada 89146
(702) 402-2991

Employment History

NV ENERGY

GAS SUPPLY PLANNING LEAD – RESOURCE OPTIMIZATION – LAS VEGAS, NV
2019 – Present

- Responsible for short and long-term planning of the Company's natural gas transportation and storage assets necessary to ensuring adequate gas supply to the Company's generation plants and to Sierra's gas distribution system.
- Responsible for reviewing and monitoring pipeline filings, negotiating rate case settlements, and supporting related efforts before the Federal Energy Regulatory Commission (FERC) and state regulatory commissions.

STAFF ANALYST/ ENGINEER – RESOURCE PLANNING DEPARTMENT – LAS VEGAS, NV
2007 – 2019

- Perform technical analysis and evaluation of the capital cost, production cost, and reliability of various transmission, generation, purchase power, and demand side alternatives being considered by the Company.
- Project management of regulatory filings submitted to the Public Utilities Commission of Nevada. Assist in the preparation of testimony and exhibits and respond to data requests.

SENIOR COMPLIANCE CONSULTANT – COMPLIANCE DEPARTMENT – LAS VEGAS, NV
2006 – 2007

- Assisted in the establishment, implementation and monitoring of an effective compliance program.
- Audited several departments to insure Sarbanes-Oxley compliance.

CHEVRON CORPORATION

ASSISTANT EXECUTIVE DIRECTOR – NEVADA COGENERATION ASSOCIATES #1 AND #2
LAS VEGAS, NEVADA
2000 – 2006

- Responsible for the engineering activities of two 85 MW cogeneration facilities which provided electricity to Nevada Power Company under long-term contracts.
- Coordinated all environmental compliance, including Title V air permits.
- Assisted in the operations and maintenance of the facilities to insure safe operations and optimized plant performance.

SOUTHWEST GAS CORPORATION

SUPERVISOR – MAJOR ACCOUNTS DEPARTMENT – LAS VEGAS, NV
1993 – 2000
- Supervised the activities of Industrial Gas Engineers in Nevada, Arizona and California.
- Coordinated and administered natural gas supplies and interstate transportation service to power generation, large industrial and commercial customers.
- Developed programs to maintain or increase the corporate margin from power generation, large industrial and commercial customers.

INDUSTRIAL GAS ENGINEER – MAJOR ACCOUNTS DEPARTMENT – PHOENIX, AZ
1989 – 1993
- Maintained contact and provided technical assistance for power generation, large industrial and commercial gas customers.
- Negotiated contracts for customers served under transportation and optional fuel rate schedules.
- Promoted natural gas technology including cogeneration, natural gas air-conditioning and compressed natural gas vehicles.

ENGINEER – ENGINEERING DEPARTMENT – PHOENIX, AZ
1986 – 1989
- Designed gas distribution facilities including high pressure and distribution gas piping, regulating stations, meter sets and telemetry.
- Provided work direction and conducted the performance reviews for several Engineering Technicians and Drafters.
- Special projects included an emergency valve isolation plan and over-pressure protection review.

EXXON COMPANY, U.S.A.

SENIOR PROJECT ENGINEER – PRODUCTION DEPARTMENT – CORPUS CHRISTI, TX
1982 – 1986
- Designed oil and gas production facilities including gathering lines, oil storage sites and separation and metering stations. Responsible for the design, material specification, cost estimating and project management necessary during construction.

MECHANICAL CONTACT ENGINEER – REFINING DEPARTMENT – BAYTOWN, TX
1980 – 1982
- Responsible for maintaining the operation of several refinery process units. Duties included solving daily maintenance problems as well as designing and implementing quality and production improvements. This assignment provided extensive experience with heat exchangers, furnaces, pumps and compressors.

EDUCATION

STEVENS INSTITUTE OF TECHNOLOGY – HOBOKEN, NEW JERSEY
- Bachelor of Engineering – with Honor, awarded May 1980
- Major: Mechanical Engineering

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, VINCENT VITIELLO, 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: May 31, 2024

VINCENT VITIELLO

PATRICIA RODRIGUEZ

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05___

Prepared Direct Testimony of

Patricia Rodriguez

SECTION I: INTRODUCTION AND PURPOSE IF TESTIMONY

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

A. My name is Patricia Rodriguez. My current position is Director, Energy Services Optimization, 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" or "NV Energy"). My business address is 6226 West Sahara Avenue in Las Vegas, Nevada. I am filing testimony on behalf of NV Energy.

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

A. My professional experience includes more than 19 years in the utility industry. I have a Bachelor of Science in Electrical Engineering and have been employed by NV Energy since May 2005. Prior to my current position, I held positions in Distribution Planning, Resource Planning, Demand Side Management, and Project Controls. My statement of qualifications is attached as **Exhibit Rodriguez-Direct-1.**

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

A. As the Director of Energy Services Optimization, I provide direction and leadership for the optimization of customer programs and distributed energy resource technologies for the benefit of the grid and NV Energy customers through the Distributed Resource Plan ("DRP"). I am also responsible for the regulatory compliance, financial planning and reporting, stakeholder management, technical analysis, systems implementation, and customer outreach for Integrated Energy Services.

4. Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?

A. Yes, I have testified in several proceedings before the Commission. Most recently, I provided testimony before this Commission in Docket Nos. 18-03002, 18-03003, 18-03004, 18-06003, 19-07004, 19-07005, 20-07004, 21-02004, 21-06001, 22-07003, 22-09006, 23-06044, and 23-09002.

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

A. My testimony supports the following sections of the DSM Plan:

- NV Energy's request that the Commission accept its Joint Demand Side Management Plan ("DSM Plan"). The DSM Plan provides the results of the 2023 program year, a status update on the 2024 program year, and presents the analysis performed by NV Energy to develop the DSM Plan for the three-year action plan period (2025-2027) of the Companies' Joint 2024 Integrated Resource Plan ("IRP"). In adherence to Nevada Administrative Code ("NAC") 704.9212(1)(b), the DSM Plan proposes a new DSM portfolio goal for

Commission approval: "Grid Value Portfolio" which implements an energy savings goal of 0.7 percent of retail energy sales and introduces an incremental demand response capacity level of approximately 175 megawatts over the three year period.

- All parts of the DSM Plan not sponsored or supported by Christopher Belcher, Robert Oliver, Lark Lee, Tom Hines, Snuller Price, Kenneth Skinner, Michael Brown and Adam Grant; and
- Together with Christopher Belcher, NV Energy's request that the Commission find it has complied with the directives of the Commission's order in Docket Nos. 22-07004 and 23-06044.

I am also supporting the following sections of the Distributed Resources Plan ("DRP") narrative:

- Section 5.B - *DRP Coordination with Other Components of the IRP and Commission-Approved Programs*, with the exception of subsection 10 which is supported by Adam Grant.

I also discuss NV Energy's compliance with two directives from the Commission:

- The Post Incentive Installation Survey Data report included in the DRP as Technical Appendix DRP-8.
- The Energy Storage Device charging report included in the DRP as Technical Appendix DRP-9.

6. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?

A. Yes. I am sponsoring the following exhibits and technical appendices:

- **Exhibit Rodriguez-Direct-1** - Statement of Qualifications.
- **Technical Appendix DRP- 8** – The Post Installation Survey Data Report

- **Technical Appendix DRP- 9 –** The Energy Storage Device Charging Report

7. Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. In section II, I describe the DSM Plan energy savings goals and development process for the proposed 2025 through 2027 program years. In Section III, I summarize NV Energy's requests for approvals, compliance, and portfolio funding flexibilities. Lastly, in Section IV, I discuss section 5.B in the DRP, titled "*Coordination with Other Components of the IRP and Commission-Approved Programs*" which provides the Companies' review of the existing legislatively-mandated programs addressing the deployment of distributed energy resource ("DERs"), including energy education, DSM, clean energy, and supplementary tariffs. I also sponsor the Post Incentive Installation Survey Data and the Energy Storage Systems and System Peak Report included as the two Technical Appendices DRP-8 and DRP-9, respectively, in Section IV of my testimony.

SECTION II: DEMAND SIDE MANAGEMENT PLAN DEVELOPMENT

8. Q. PLEASE SUMMARIZE THE CURRENT DSM PLAN'S SAVINGS GOAL THAT IS APPROVED FOR PROGRAM YEARS 2022 THROUGH 2024 BY THE COMMISSION PURSUANT TO NAC 704.9212(1)(a).

A. The current DSM plan's savings goal is to achieve an amount of energy savings equal to an average reduction of 1.1 percent of the forecasted weather normalized sales of the electric utility during the plan period.

9. Q. DOES THE NAC SET A DIFFERENT REQUIREMENT BEGINNING IN 2025?

A. Yes. Pursuant to NAC 704.9212 (1)(b), for any period beginning on or after January 1, 2025, the goal for energy savings is to be "established by the Commission in an order denying, approving or modifying the most recent demand side plan." In other words, the goal is no longer set at the 1.1 percent of the forecasted weather normalized sales by regulation and the Companies may present new saving goals to the Commission for consideration. Therefore, the Companies present a new approach in this filing.

10. Q. PLEASE DESCRIBE THE PROPOSED "GRID VALUE" PORTFOLIO.

A. The Companies' proposed plan for Commission approval is the "Grid Value" portfolio. The Grid Value portfolio proposes an energy savings goal of 0.7 percent of forecasted retail energy sales statewide and also establishes a parallel goal of approximately 175 megawatts ("MW") of demand reduction capacity over the three-year period by installing flexibly scheduled distributed energy technologies. These DER technologies are an opportunity to address the changing dynamics of the Companies' power grid. The energy and demand savings and opportunities presented in the Grid Value are more cost effective and provide more net benefits to customers with a lower rate impact in the Action Plan period than retaining the prior approach. It should be noted that while the percentage change has been reduced, the proposed budget has increased compared to the prior plan period, and increase each year within the proposed action plan period.

11. Q. PLEASE DESCRIBE THE COMPARISON "TRADITIONAL" PORTFOLIO THAT IS ALSO PRESENTED IN THIS FILING FOR COMPARISON PURPOSES.

A. Recognizing the Grid Value portfolio proposes a new way of approaching DSM in Nevada, the Companies elected to present an alternative Traditional portfolio for comparison purposes. The Traditional portfolio represents a DSM Plan that continues to meet the Companies' prior goal of energy savings equal to an average of 1.1 percent of forecasting retail energy sales statewide, but does so with fewer customer benefits and a higher rate impact.

12. Q. WHY ARE THE COMPANIES PROPOSING A NEW DSM PLAN ENERGY SAVINGS GOAL IN THIS PLAN?

A. A new DSM Plan goal can optimize the changing nature of the Companies' power grid and resource adequacy needs. The Grid Value portfolio and its energy and demand savings targets provide opportunities for additional customer and grid benefits as compared to a Traditional portfolio. These include:

1. **DSM Plan total cost and rate impacts**. The energy savings requirement needed for the DSM programs to meet the current goal will need to scale with Nevada's population and its energy usage growth in the coming years. Nevada is attracting more residential customers, as well as more commercial customers with large and constant loads, including 24-hour operating data centers, 24-hour operating electric vehicle charging stations, and possibly other energy dense sectors as the state's economy evolves. As expressed in the Energy Supply Plan submitted in this IRP, the anticipated retail energy sales over the next three years are expected to increase to 102,663,626 MWH. In response to these growing energy supply needs, the Companies propose in its Grid Value portfolio a total DSM Plan budget of $248,007,000. The rate impact for the Grid Value portfolio is more beneficial for customers in comparison to the Traditional portfolio that has a total DSM Plan budget of $354,394,000. NV

Energy provides further details on the rate impact analysis for both portfolios in Technical Appendix DSM-30 in the DSM Action Plan.

2. **Reducing renewable energy curtailments.** The Companies continue to procure more renewable energy resources, a majority of which consist of solar energy that is most productive during midday hours. This means there are hours of the day when there is more energy produced than there is load demand to use it. The Companies are obligated to pay for some of that excess unused renewable energy according to contractual power purchase agreements regardless of whether it is used. Flexible distributed energy resources controlled by the utility provide an opportunity to use what would otherwise be excess renewable energy. Therefore, introducing a DSM portfolio target that encourages the Companies to install flexible resources can help reduce the loss of renewable energy and the power purchase agreements' curtailment fees, thereby increasing customer benefits.
3. **Resource adequacy.** Growing dispatchable demand reduction capacity will increase the Companies' capabilities to mitigate local and system wide peak load conditions during which available energy market or marginal generation sources are scarce. The Companies have certified their demand response assets as 10-minute non-spinning operating reserves which can be called upon during peak load hours to maintain resource adequacy. The Traditional portfolio only has a goal of energy savings, while the Grid Value portfolio is focused on growing dispatchable DR capacity.
4. **Flexible resources for reducing local or regional system overloads.** Dispatchable resources that are capable of shifting peak loads can help the Companies propose non-wire alternatives to more efficiently operate currently

installed grid equipment. The Grid Value portfolio will support the increase in installed demand response and flexible distributed resource capacities to assist the analysis of non-wires alternatives and local net benefit analysis required in the Companies' DRP. The Traditional portfolio does not support the Companies strategy to increase flexible load.

13. Q. HOW HAS THE MARKET POTENTIAL STUDY INFORMED THE CREATION OF THESE TWO PORTFOLIOS?

A. The Companies conducted a new market potential study, which identifies various levels of savings potential given the most recent Nevada-specific market information available. The market potential results presented various types of measures and their likely future potential levels of adoption. This information is helpful for determining what amounts of energy and demand savings are feasible. For more details on the MPS, please refer to the testimony of Snuller Price.

14. Q. ARE ENERGY EFFICIENCY AND CONSERVATION VALUED IN THE COMPANIES' PROPOSED DSM PLAN?

A. Yes, energy efficiency and conservation programs assist customers in reducing their monthly energy bills by educating them about their personal energy behaviors, opportunities to reduce the energy usage and provides products and services that make their appliances and home energy profile more economical and efficient. Both the proposed Grid Value and the comparison Traditional portfolio contain a kilowatt-hour savings component in the form of energy efficiency and conservation programs.

15. Q. WHAT WERE THE NON-ENERGY TOTAL RESOURCE COST RATIOS OF THE GRID VALUE AND TRADITIONAL PORTFOLIOS ACCORDING TO THE COMPANIES' COST-EFFECTIVENESS TESTING?

A. According to Table DSM-1, the Grid Value portfolio was found to have a Non-energy Total Resource Cost ("NTRC") ratio of 1.96 for NV Energy over the three-year DSM Plan period. According to Table DSM-2, the Traditional portfolio was found to have an NTRC ratio of 1.29 for NV Energy over the three-year DSM Plan period. These NTRC values were calculated using the Ace Guru cost-effectiveness model which the DSM Collaborative stakeholders and the Commission are familiar with and have accepted in prior DSM reports.[1] These ratios demonstrate that the Grid Value portfolio is the more cost-effective approach.

16. Q. WHY IS NV ENERGY RECOMMENDING APPROVAL OF THE GRID VALUE PORTFOLIO?

A. The regulations no longer constrain the Companies or the Commission to a pre-set energy savings goal. Instead, the DSM Plan can now evolve to ensure customer programs and investments are providing additional benefits through enabling flexible load. As loads continue to grow and future controllable technologies such as smart thermostats, managed EV charging, and battery storage come online, the incremental benefit of a Grid Value approach over a Traditional approach will continue to increase over time.

17 Q. IS THE DSM GRID VALUE PORTFOLIO EQUIVALENT TO THE MARKET POTENTIAL STUDY?

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[1] Docket 22-07004, November 14, 2022, Order, Attachment A Stipulation at 6, para. 10

A. No. To create a portfolio that served all customers, met the statutory requirements regarding low-income and historically underserved communities, and integrated customer and stakeholder feedback into program design evolution, the Companies include some non-cost-effective residential measures within the portfolio.

<u>SECTION III: DSM PLAN COMPLIANCE AND REQUESTS FOR APPROVAL</u>

18. Q. WHY SHOULD THE COMMISSION APPROVE NV ENERGY'S PROPOSED DSM GRID VALUE PORTFOLIO AND ITS BUDGET FOR THE ACTION PLAN YEARS 2025 THROUGH 2027 AS PRUDENT?

A. The Commission should approve NV Energy's DSM Grid Value portfolio because it is cost-effective and it strikes a balance between achieving energy efficiency and conservation savings and growing the flexible distributed energy resource capacity that can improve grid operation and reliability. The most significant benefits of the proposed DSM Grid Value portfolio are:

- The DSM portfolio of programs provides customers with viable options for managing their energy consumption and reducing their utility bills;
- Flexible distributed energy resources with load shaping capabilities can improve the operation of the electric grid and increase the amount of resources available for non-wires alternative solutions as discussed in the Distributed Resources Plan. Flexible resources in the DSM Grid Value portfolio include demand response technologies, energy storage, and grid-enabled smart hot water heaters;
- The renewable energy produced by variable sources can be stored using more of the flexible resources presented in the DSM Grid Value portfolio, which will increase the amount of renewable energy consumed in Nevada and will reduce the contractual payments for unused curtailed renewable energy;

- The DSM Grid Value portfolio helps address the future open capacity position of NV Energy through cost-effective energy efficiency, demand savings, and demand response;
- As shown in Table DSM-1, the NTRC cost-benefit ratio for the statewide NV Energy DSM Grid Value portfolio using the approved Ace Guru cost effectiveness model during the action plan period are: 1.88 for 2025, 1.94 for 2026, and 2.03 for 2027. The NTRC results show that the estimated non-energy benefits provided by the DSM portfolio of programs exceed the costs associated with the portfolio. The NTRC test is employed to evaluate the effect of DSM on total expenditures for utility services for both participants and non-participants;
- As shown in Table DSM-1, the DSM Grid Value portfolio is estimated to bring a net benefit to the communities served by NV Energy of $114 million for 2025, $136 million for 2026, and $164 million for 2027;
- The DSM Grid Value portfolio continues the momentum of the work accomplished by the DSM programs approved by the Commission for nearly two decades and keeps intact the core of local contractors that have been developed and have become important program partners in the delivery of the programs. These benefits are provided for all customers and communities served; and
- The portfolio has been designed to meet at least a ten percent expenditure level in support of income-qualified customer and historically underserved community participation.

19. Q. IS NV ENERGY ABLE TO REALLOCATE FUNDS WITHIN THE DSM PORTFOLIO?

A. Yes. As previously recognized by the Commission, NV Energy is able to utilize its management discretion to reallocate funds to an over-performing DSM program from a DSM program that is projected to underspend, while staying within the approved portfolio budget level, realizing the energy savings target, and achieving the low-income expenditure requirements.[2]

SECTION IV: DISTRIBUTED RESOURCES PLAN SUPPORT

20. Q. WHAT SPECIFIC DRP REQUESTS FOR APPROVAL ARE YOU SUPPORTING IN THIS TESTIMONY?

A. Section 11 of the DRP narrative describes the Companies' specific requests for approval, which include compliance with the appropriate sections of Nevada Administrative Code ("NAC") determinations. I support the request for Commission finding that NV Energy identified existing programs and tariffs approved by the Commission that address the deployment of DERs and the methods of effectively coordinating these programs to maximize the locational benefits and minimize the incremental costs of DERs as discussed in Section 5.B of the DRP narrative in compliance with NAC 704.9237(2)(c).

21. Q. ARE NV ENERGY'S IDENTIFICATION OF THE EXISTING PROGRAMS, TARIFFS AND INCENTIVES, AND METHODS OF COORDINATING THE DEPLOYMENT OF DERS WITH SUCH PROGRAMS IN SECTION 5.B OF THE DRP NARRATIVE AS PRUDENT IN COMPLIANCE WITH NAC 704.9237(2)(c)?

A. Yes. NV Energy lists and describes all the appropriate existing Commission-approved programs, tariffs, and incentives that address the deployment of DERs in

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[2] Docket No. 19-07004, December 24, 2019, Order at 5, para. 6.

Section 5.B.1 of the DRP Narrative. These programs, tariffs, and incentives relate to energy efficiency, DR, solar photovoltaic distributed generation systems, electric vehicles, and energy storage, all of which are technologies defined in NAC 704.90583 as distributed resources. Therefore, NV Energy's identification of the existing Commission-approved programs, tariffs, and incentives in Section 5.B.1 of the DRP Narrative meets the requirements of NAC 704.9237(2)(c).

NV Energy describes how the identified Commission-approved programs cost-effectively coordinate with each other and with the unique activities and analyses in the DRP (e.g., the Hosting Capacity and Non-Wires Alternatives analyses) to maximize the locational benefits and minimize the incremental costs of distributed resources in Section 5.B.2 of the DRP narrative. The information provided in that section also meets the requirements of NAC 704.9237(2)(c).

22. Q. IS NV ENERGY'S IDENTIFICATION OF THE EXISTING PROGRAMS, TARIFFS AND INCENTIVES, AND METHODS OF COORDINATING THE DEPLOYMENT OF DERS WITH SUCH PROGRAMS IN SECTION 5.B OF THE DRP NARRATIVE PRUDENT AND IN COMPLIANCE WITH NAC 704.9237(2)(c)?

A. Yes. NV Energy lists and describes all the appropriate existing Commission approved programs, tariffs, and incentives that address the deployment of DERs in Section 5.B.1 of the DRP Narrative. These programs, tariffs, and incentives relate to energy efficiency, DR, solar PV distributed generation systems, and energy storage, all of which are technologies defined in NAC 704.90583 as distributed resources. Therefore, NV Energy's identification of the existing Commission-approved programs, tariffs, and incentives in Section 5.B.1 of the DRP Narrative meets the requirements of NAC 704.9237(2)(c).

NV Energy describes how the identified Commission-approved programs cost-effectively coordinate with each other and with the unique activities and analyses in the DRP (e.g., the Hosting Capacity and Non-Wires Alternatives analyses) to maximize the locational benefits and minimize the incremental costs of distributed resources in Section 5.B.2 of the DRP narrative. The information provided in that section also meets the requirements of NAC 704.9237(2)(c).

23. Q. HOW DID THE COMPANIES COMPLY WITH THE DIRECTIVES AND STIPULATION IN DOCKET NO. 23-02001?

A. NV Energy complied with directive four in Docket No. 23-02001 by providing: (1) the 2023 Energy Storage Systems and System Peak Report in Technical Appendix DRP-9; (2) the Post Incentive Installation Survey Data Results report is provided in Technical Appendix DRP-8.

24. Q. PLEASE GENERALLY DESCRIBE THE CONTENT OF SECTION 5.B OF THE DRP NARRATIVE THAT YOU ARE SUPPORTING.

A. Section 5.B - Coordination with Existing Commission-Approved DER Programs provides the Companies' review of the existing legislatively-mandated programs addressing the deployment of DERs, including energy education, DSM, clean energy incentive programs, and supplementary tariffs.

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

25. Q. IS NV ENERGY'S IDENTIFICATION OF THE EXISTING PROGRAMS, TARIFFS AND INCENTIVES, AND METHODS OF COORDINATING THE DEPLOYMENT OF DERS WITH SUCH PROGRAMS IN SECTION 5.B OF THE DRP NARRATIVE PRUDENT AND IN COMPLIANCE WITH NAC 704.9237(2)(c)?

A. Yes, NV Energy lists and describes all the appropriate existing Commission-approved programs, tariffs, and incentives that address the deployment of DERs in Section 5.B.1 of the DRP narrative. These programs, tariffs, and incentives relate to energy efficiency, DR, solar PV distributed generation systems, and energy storage, all of which are technologies defined in NAC 704.90583 as distributed resources. Therefore, NV Energy's identification of the existing Commission-approved programs, tariffs, and incentives in Section 5.B.1 of the DRP narrative meets the requirements of NAC 704.9237(2)(c).

NV Energy describes how the identified Commission-approved programs cost effectively coordinate with each other and with the unique activities and analyses in the DRP (e.g., the Hosting Capacity Analysis and Non-Wires Alternatives analyses) to maximize the locational benefits and minimize the incremental costs of distributed resources in Section 5.B.2 of the DRP narrative. The information provided in that section also meets the requirements of NAC 704.9237(2)(c)

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

A. Yes.

EXHIBIT RODRIGUEZ-DIRECT-1

STATEMENT OF QUALIFICATIONS

PATRICIA RODRIGUEZ

NEVADA POWER COMPANY d/b/a NV Energy
SIERRA PACIFIC POWER COMPANIES d/b/a NV Energy
6226 W. Sahara Ave.
Las Vegas Nevada 89146
(702) 402-2434

Education

Bachelor of Science in Electrical Engineering, University of Nevada Las Vegas 2005.

Professional Experience

2019 through present — **Director, Energy Services Optimization**
NV Energy

Responsibilities include oversight leadership of the Demand Side Management team and as of September 2020 also lead the Clean Energy team. Additional responsibilities include development and implementation, analysis and cost recovery of cost-effective statewide demand side management, Clean Energy and Transportation Electrification programs which provide exceptional service to customers.

2018 through 2019 — **Manager, Distribution Planning**
NV Energy

Responsibilities include leading and directing efforts of the engineering staff comprising Distribution Planning. Additional responsibilities include ensuing that cost effective plans specifying the scope and timing of distribution infrastructure additions and improvements necessary to maintain service reliability and accommodate future load additions are developed and periodically updated in an efficient, skillful, coordinated and timely manner.

2015 through 2018 — **Manager, Gas Transportation Planning**
NV Energy

Responsibilities include planning and analysis of gas transportation needs to ensure sufficient supply to the generation fleet and natural gas customers. Additional responsibilities include development and implementation of work plans to support corporate contract negotiations, planning, budgeting, controls, portfolio optimization, cost reduction and risk management.

2014 through 2015 — **Senior Engineer, Distribution Planning**
NV Energy

Responsibilities included performing contingency analysis, distribution load flow analysis and providing service requirements for distribution load additions for area of responsibility (NVE Northeast Region). Additional responsibilities included working on different studies for renewable Rule 15 projects.

2012 through 2014 **Staff Consultant, DSM Planning**
NV Energy

Responsibilities included the planning, development and evaluation of Demand Side Management (DSM) programs including program selection and development, financial analysis, preparation of the DSM portion of the resource plan, measurement and verification of program results, analysis of results of programs and associated reporting.

2011 through 2012 **Senior Engineer, Distribution Planning**
NV Energy

Responsibilities included performing contingency analysis, distribution load flow analysis and providing service requirements for distribution load additions for area of responsibility (NVE Northwest Region). Additional responsibilities included working on different studies for mine additions served at the distribution level.

2008 through 2011 **Engineer, Distribution Planning**
NV Energy

Responsibilities included supporting the analysis and development of hot spot solutions, completing the Long Range Capacity Plan and providing service requirements for distribution load additions for area of responsibility. Additional responsibilities included the creation of the load forecast for substation transformers and feeders, distribution load flow analysis and updating the capital budget planning initiation documents based on the new forecast.

2007 through 2008 **Senior Consultant, Project Controls**
NV Energy

Responsibilities included monitoring and updating fully integrated design and construction project schedules, providing resource histograms, analyzing, reviewing and forecasting performance for various capital projects. Additional responsibilities included providing Primavera training to project managers, functional groups and project controls staff.

2005 through 2007 **Associate Engineer, Project Controls**
Nevada Power Company

Responsibilities and accomplishments included the development and maintenance of design and construction project schedules and the integration of them into the master project management schedule. Additional responsibilities included creating monthly reports and facilitating meetings with functional group leaders and project managers to review project progress.

2005 **Student Intern, Project Controls**
Nevada Power Company

Responsibilities and accomplishments included construction schedule updates, research and data entry for various systems.

Memberships

Board member of Childrens Discovery Museum and executive SWEEP board and Vice Chair.

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, Patricia Rodriguez, 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: May 31, 2024

Patricia Rodriguez

ADAM GRANT

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05___

Prepared Direct Testimony of

Adam Grant

SECTION I: INTRODUCTION

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

A. My name is Adam Grant. I am the Director of Integrated Energy Services, Operations for Sierra Pacific Power Company d/b/a NV Energy ("Sierra" or the "Company") and Nevada Power Company d/b/a NV Energy ("Nevada Power," and, together with Sierra, the "Companies" or "NV Energy"). My business address is 6226 West Sahara Avenue in Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

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

A. My professional experience includes 17 years in the utility industry. I have held a variety of positions with NV Energy since I joined the Companies as a Communications Specialist in 2007. The details of my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Grant-Direct-1.**

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

A. As Director of Integrated Energy Services, Operations, my responsibilities include oversight of the overall delivery of the Companies' residential and commercial demand side management ("DSM") programs, transportation electrification programs, clean energy programs, and energy services customer engagement.

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4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?

A. Yes, I have testified in numerous proceedings before the Commission, most recently in Docket Nos. 22-03001/3002 (Deferred Energy Accounting Adjustment), 22-07004 (DSM Update), 23-06044 (DSM Update), 23-09002 (Distribution Resource Plan Update) and 24-02026 (Sierra's General Rate Case).

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

A. My testimony supports the following:

- Describes and summarizes Nevada Power and Sierra's Demand Side Management Plan ("DSM Plan"). The DSM Plan provides the results of the 2023 program year and provides a summary of NV Energy's portfolio of programs for the 2025-2027 Action Plan. In this filing, NV Energy presents for approval a Grid Value portfolio of programs that is cost-effective at the plan level and results in annual kilowatt hours (kWh) energy savings that is at 0.7 percent of the weather normalized retail sales forecast statewide within Nevada Power and Sierra's territories. The proposed Grid Value portfolio will feature an incremental flexible load target of 175 Megawatts ("MW") for the period. The Companies have also presented as an alternative Traditional portfolio, for comparison purposes, which was designed to meet 1.1 percent of weather normalized retail sales.

The proposed Grid Value portfolio is the Companies' recommended approach as it is cost effective and combines the enhancements contained in the alternative Traditional portfolio along with targeted investments focused on deploying diverse demand side tools in addition to energy efficiency ("EE") including demand response, load shifting, and energy storage.

I am also supporting the following section of the Distributed Resources Plan ("DRP") narrative:

- Section 10 - *Transportation Electrification Plan* ("TEP"), introduce and sponsor the Companies' proposed TEP. In addition to my testimony, Misha Pascal sponsors the proposed TEP Plan components involving the Companies' Rule 9 allowances (section F of the TEP). I sponsor the remainder of the TEP.

6. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?

A. Yes. I am sponsoring the following exhibit and technical appendices:

- **Exhibit Grant-Direct-1** Statement of Qualifications
- **Technical Appendices TEP-1 through TEP-6**

7. Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. In Section II of my testimony, I summarize the 2023 DSM program year results. In Section III, I summarize the DSM Plans for Nevada Power and Sierra for the Action Plan period and discuss the enhancements NV Energy proposes in this filing to the portfolio of programs. In Section IV, I explain how the Companies developed the TEP in collaboration with stakeholders and industry consultants and provide the budget overview. In Section V, I sponsor the request to extend the ESB-V2G tariff, Section VI provides the overview of the TEP's programs, and in Section VII, I describe the cost benefit testing, cost recovery mechanism and the potential rate impact of the TEP.

SECTION II: SUMMARY OF DSM PROGRAM YEAR 2023 RESULTS

8. Q PLEASE SUMMARIZE THE PERFORMANCE OF NV ENERGY'S DSM PORTFOLIO FOR 2023.

A. The portfolio of DSM programs delivered in 2023 achieved a Non Energy Benefits Total Resource Cost ("NTRC") ratio of 1.99 and will provide more than $106 million dollars of net benefits to customers over the lives of the measures installed. Overall, the portfolio achieved 327,800,761 kWh or 98.1 percent of the targeted energy savings and 233,683 kilowatt ("kW") or 78.5 percent of the targeted demand savings. Program expenditures totaling $58,510,440 were less than budgeted at 92.3 percent of the approved budget $63,401,004.

At Nevada Power, the portfolio achieved 273,408,877 kWh or 116.8 percent of the targeted energy savings and 205,464 kW or 78.1 percent of the targeted demand savings. Program expenditures totaling $45,474,536 were less than budgeted at 94.5 percent of the approved budget $48,101,501.

At Sierra, the total verified energy savings for the 2023 programs were 54,391,884 kWh or 54.5 percent of the targeted energy savings. The demand savings totaled 28,219 kW or 81.6 percent of the targeted kW savings. Program expenditures totaling $13,035,904 were less than budgeted at 85.2 percent of the approved budget of $15,299,503.

Table DSM-14, 2023 Financial Results, and Table DSM-15, 2023 Demand and Energy Savings Results, found in Section 2 of the DSM Narrative in this filing provide the performance for the portfolio in aggregate and for each program. A more detailed description and analysis of the performance of each program in 2023 is included in the program data sheet provided in Sections 4 through 6 and in the Measurement and Verification ("M&V") reports provided in Technical Appendix Items DSM-11 through DSM-23.

SECTION III: THE ANALYSIS AND PROPOSAL OF DSM PROGRAMS FOR THE 2025 THROUGH 2027 PROGRAM YEARS

9. Q. PLEASE SUMMARIZE AND DESCRIBE THE DSM PLAN FOR THE 2025 THROUGH 2027 ACTION PLAN PERIOD.

A. NV Energy's proposed DSM Plan contains a portfolio of Grid Value energy efficiency and flexible load demand response programs for the Action Plan Period in both Nevada Power and Sierra's service territories addressing the needs of both residential and commercial customers.

The proposed Grid Value portfolio is designed to meet or exceed energy savings averaging 0.7 percent of forecasted weather normalized retail sales for the January 1, 2025, through December 31, 2027 Action-Plan Period statewide and a flexible load component total of 165 MW of new demand response. Nevada Power and Sierra are requesting Commission approval for this proposed Grid Value portfolio as the 2025-2027 DSM Plan.

The Companies also present an alternative Traditional portfolio, for comparison purposes, designed to meet 1.1 percent of weather normalized retail sales in savings statewide. The alternative Traditional portfolio has a less robust demand response program, does not have a flexible load goal, and focuses on measures that are kWh-savings driven, regardless of when the savings is achieved.

The Companies undertook a multifaceted process to design and create the two portfolios. Steps included incorporating data from many sources, including a new Market Potential Study ("MPS"), historical performances of the NV Energy DSM programs, recommendations from the independent third-party Measurement and Verification ("M&V") contractor, as well as input from the DSM Collaborative and portfolio examination from other utilities. Please refer to the Testimony of Tom Hines of Tierra Resource Consultants for a more in-depth description of the process by which the proposed Grid Values and alternative Traditional portfolios were designed.

10. Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN THE RECOMMENDED GRID VALUE PORTFOLIO AND THE TRADITIONAL PORTFOLIO.

A. As noted above, the proposed Grid Value portfolio meets a revised energy savings goal statewide, as well as an incrementally increased flexible load goal in DR Programs. This is accomplished by increasing investments that provide notably greater peak kW savings and load reductions by growing DR and load management programs designed to promote the adoption and coordinated dispatch of distributed energy resources ("DERs"). The goal is to shift electric loads to less costly times and to absorb midday renewable energy, while also reducing peak demand caused by the increasing adoption of electric vehicles ("EVs") and other electrification measures.

For comparison, the Traditional portfolio meets the previous energy savings goal of a three-year average of 1.1 percent of forecasted weather normalized retail sales statewide by focusing on kWh savings achieved by proposing new EE programs and growing the Companies' existing EE programs for all customers, with limited growth of DR programs.

The proposed Grid Value portfolio provides a net benefit to customers of more than $413 million where the Traditional portfolio provides net benefits of approximately $165 million.

11. Q. WHAT ARE THE PROPOSED BUDGETS AND TARGETS FOR EACH OF THE TWO PORTFOLIOS?

The budget for NV Energy's statewide proposed Grid Value is $76,076,000 in 2025 ($55,863,000 at Nevada Power and $20,213,000 at Sierra), $82,746,000 in 2026 ($60,741,000 at Nevada Power and $22,005,000 at Sierra), and $89,185,000 in 2027 ($65,259,000 at Nevada Power and $23,926,000 at Sierra). Tables DSM-4 through DSM-6 in the DSM Narrative provide the budgets broken out by company, program, and year.

The estimated annual energy savings in kWh statewide for the proposed Grid Value portfolio is 235,644,000 kWh in 2025 (188,144,000 kWh at Nevada Power and 47,500,000 kWh at Sierra), 246,549,000 kWh in 2026 (197,922,000 kWh at Nevada Power and 48,627,000 kWh at Sierra), and 258,563,000 kWh in 2027 (208,742,000 kWh at Nevada Power and 49,821,000 kWh at Sierra) which equates to 0.7 percent of forecasted retail sales for three years in each of Nevada Power and Sierra territories. Tables DSM-4 through DSM-6 also provide the energy savings broken out by company, program, and year.

The proposed Grid Value portfolio's estimated annual coincident demand savings in kW in 2025 is 233,656 kW (197,250 kW at Nevada Power and 36,405 kW at Sierra); in 2026, 264,570 kW (222,098 kW at Nevada Power and 42,472 kW at Sierra); and in 2027, 300,576 kW (250,028 kW at Nevada Power and 50,548 kW at Sierra); Tables DSM-4 through DSM-6 also provide the demand savings broken out by company, program, and year.

The Grid Value portfolio is designed to enhance flexible load measures and an increased demand response program which is estimated to garner 49.2 MW of new dispatchable savings in 2025 (41.8 MW at Nevada Power and 7.4 at Sierra); 58.6 MW in 2026 (49.1 MW at Nevada Power and 9.5 at Sierra); and 66.7 MW in 2027 (55.2 MW at Nevada Power and 11.4 MW at Sierra).

The budget for the alternative Traditional portfolio is $113,185,000 in 2025 ($85,198,000 at Nevada Power and $27,987,000 at Sierra), $117,610,000 in 2026 ($89,314,000 at Nevada Power and $28,296,000 at Sierra), and $123,599,000 in 2027 ($96,576,000 at Nevada Power and $27,023,000 at Sierra). Tables DSM-7 through DSM-9 in the DSM Narrative provide the budgets broken out by company, program, and year.

The alternative Traditional portfolio has an estimated annual energy savings of 368,026,000 kWh (292,872,000 kWh at Nevada Power and 75,154,000 kWh at Sierra) in 2025, 386,212,000 kWh (309,141,000 kWh at Nevada Power and

77,071,000 kWh at Sierra) in 2026, and 403,265,000 kWh (328,107,000 kWh at Nevada Power and 75,158,000 kWh at Sierra) in 2027. Tables DSM-7 through DSM-9 also provide the energy savings broken out by company, program, and year.

The alternative Traditional portfolio's estimated annual coincident demand savings in kW in 2025 is 224,555 kW (188,115 kW at Nevada Power and 36,440 kW at Sierra); in 2026, 224,685 kW (187,689 kW at Nevada Power and 36,996 kW at Sierra); and in 2027, 229,110 kW (192,839 kW at Nevada Power and 36,271 kW at Sierra). Tables DSM-7 through DSM-9 also provide the demand savings broken out by company, program, and year.

12. Q. DO THE PROPOSED BUDGETS FOR THE DSM PLAN'S PROGRAMS INCLUDE EXPENSES FOR MARKETING?

A. Yes. NAC 704.9523(2)(a) expressly allows for utilities to recover costs incurred for the advertising and marketing of DSM programs, and these costs are included within the program budgets proposed in this filing. In order to effectively reach a broad swath of customers, the Companies employs a multi-faceted marketing approach to increase awareness of its DSM programs, branded as "PowerShift." The Companies use many different media and formats, including radio, television, social media, events, direct and electronic mail as well as bill inserts and onserts. In addition, marketing and outreach efforts with local community partners and venues where a large number of customers gather in a single location can provide effective opportunities to market these programs and encourage energy efficiency initiatives.

13. Q. IS NV ENERGY MAKING ANY FUNDAMENTAL CHANGES TO ITS STRATEGIES TO DELIVER A PORTFOLIO OF PROGRAMS PROPOSED FOR THE ACTION PLAN PERIOD IN THE FILING?

A. No. NV Energy is continuing its strategy to integrate EE and DR programs by customer segment. NV Energy is proposing integrated sets of services within both presented portfolios designed to maintain a practical budget, optimize energy and demand savings, and increase participation, all while using a more personalized and customized approach. The programs are bundled into the following offerings: 1) Education Services; 2) Residential Services; and 3) Non-Residential Services. Budgets, savings, and cost-effectiveness have been presented at the program level to provide the same level of transparency as prior year filings.

14. Q. PLEASE EXPLAIN THE BENEFITS OF AN INTEGRATED APPROACH.

A. A fully integrated approach leverages the benefits of multiple programs based on individual customer needs. This implementation style simplifies the process for customers to participate in one or more programs at the same time, and it achieves economies of scale by spreading costs over multiple programs.

In addition, NV Energy continues to utilize previous investments in upgraded technologies and systems to proactively use comprehensive analytic tools, such as disaggregated energy consumption data, powerful data analytic tools, billing histories, weather data, customer segmentation, appliance analysis, and information gathered from third party sources. These modern tools provide relevant actionable analysis, which leads to specific action plans customers can utilize to manage energy use by improving home function, upgrading appliances and equipment, and changing energy use behavior.

15. Q. ARE THE COMPANIES ADDING ANY NEW PROGRAMS OR SIGNIFICANTLY REDESIGNING ANY PROGRAMS FOR THE 2025-2027 ACTION PLAN PERIOD?

A. Yes. NV Energy is proposing several new and/or revised offerings. Including:

- The Companies are renaming the Equipment and Plug Loads Program to the Residential Home Energy Saver Program and concurrently separating heating and cooling measures into a new Residential AC and Heat Pumps program.
- NV Energy will combine both the online and in-home assessments program with the Direct Install and Home Improvements program as the newly created Energy Assessments and Direct Install program and NV Energy will offer a new Income Qualified Multifamily program. These programs, described in Q&As 19 through 21 below and in the program data sheets, are added to supplement NV Energy's residential portfolio.

16. Q. ARE ANY PROGRAMS BEING DISCONTINUED?

A. No. NV Energy is not proposing to discontinue any programs that are in the current portfolio, however, as described above, some of the programs will be bundled together in differently.

17. Q. ARE THE PROGRAMS WITHIN THE PROPOSED GRID VALUE PORTFOLIO AND THE COMPARISON TRADITIONAL PORTFOLIO THE SAME?

A. Yes. Each portfolio has the same set of programs. The differences, as described above, are the individual measures within the program and the focus on grid value savings and flexible load. This provides additional customer benefits in the proposed Grid Value portfolio.

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

18. Q. WHAT PROGRAMS ARE INCLUDED IN THE RECOMMENDED GRID VALUE AND THE TRADITIONAL PORTFOLIOS?

A. The following programs are included in both presented portfolios:

1. Education Services
   a. Energy Education Program
   b. Energy Reports Program
   c. Program Development Program
2. Residential Services
   a. Energy Assessments and Direct Install Program
   b. Home Energy Saver Program
   c. Residential AC and Heat Pumps
   d. Residential Codes and New Construction Program
   e. Income Qualified Multifamily Program
   f. Qualified Customer Program
   g. Residential Demand Response (Manage and Build) Program
3. Non-Residential Services
   a. Schools Program
   b. Business Energy Services Program (including Non-Profit Agency Grants)
   c. Commercial Demand Response (Manage and Build) Program

19. Q. PLEASE DESCRIBE THE PROGRAMS WITHIN EDUCATION SERVICES.

A. Education Services focuses on achieving increased awareness and participation in the portfolio of programs through energy education, for NV Energy's DSM products and services. Education Services is composed of three programs: Energy Education, Energy Reports, and Program Development.

The **Energy Education program** provides educational tools and tips to NV Energy's residential and small commercial customers to encourage energy efficiency and savings opportunities. This strategic outreach not only endeavors to foster awareness and participation in DSM and EE offerings, but it also strives to maintain on-going communication and build a positive relationship with customers, while positioning the Companies as a reliable resource and partner to help maximize energy savings. In the Grid Value portfolio, this program will also be expanded beyond the current educational messaging to include a focus on saving energy on-peak and shifting energy to off-peak time periods through current educational channels.

The **Energy Reports program** delivers reports to residential customers in each of NV Energy's territories to inform and motivate them to take action to save energy by using electricity more efficiently and to drive participation in other DSM programs. The Program focuses on achieving two results. First, it seeks to motivate customers to change or modify their behavior in context with similar households. Second, it seeks to provide customers with personalized information, energy-saving products and services, and practical ways to save energy and money. In the Grid Value portfolio, these efforts will be complemented through new messaging to explain TOU rates and the benefits and opportunities of load shifting so customers understand the value of more effectively monitoring and managing when and how much energy they are using.

The **Program Development program** investigates and tests emerging products or services that may enhance the DSM portfolio. Products, services, and program concepts are investigated to determine if they are opportunities to enhance or improve existing DSM program designs. Program efforts include market research, preliminary identification, assessment, and testing of technologies, appliances, measures, and delivery models. In the Grid Value portfolio, Program Development will prioritize the testing of emerging technologies and services with the potential to affect our grid and customers. This will include new offerings to assist customers who may be underserved by existing programs, such as low income, multi-family, small/medium businesses, and agriculture customers.

Details of each program are provided in the program data sheets.

20. Q. PLEASE DESCRIBE THE PROGRAMS WITHIN RESIDENTIAL SERVICES.

A. A variety of residential services are available to the Companies' approximately 1.2 million residential electric customers. To address this varied set of customers, NV Energy will offer a bundled set of products and services targeted to reach much of the residential market and provide customers with multiple opportunities to participate. These products and services will be implemented in an integrated fashion, which will allow a large number of customers to participate and benefit from one or more of the products and services offered.

Residential services focus on providing customers with simple ways to participate and encourages them to make long-term commitments to reduce their energy usage. The portfolio of residential services is comprised of seven programs including Energy Assessments and Direct Install, Home Energy Saver program, Codes and New Construction, Residential AC and Heat Pumps, Qualified Customer program, Qualified Income Multifamily and Residential DR programs.

The **Energy Assessments and Direct Install program** combines the following programs into one streamlined customer offering: Online Energy Assessment, In-Home Energy Assessment, and Direct Install and Home Improvements. This new comprehensive Energy Assessments and Direct Install Program will allow NV Energy to better serve residential customers as they initiate the process of improving their homes' energy efficiency by delineating a clear program participation pathway that integrates home improvement opportunities across the DSM portfolio and provides a personalized approach to guide customers through the process. This program provides a tool for customers to perform an online energy assessment enabling them to save energy and reduce energy bills. This Program supplements and supports the Energy Education program and serves as a gateway to participation in other DSM programs by providing tips and recommendations, both online and through a certified technician in person.

During the in-home assessment, customers will be provided with direct installation of low-cost energy efficient measures in their home as well as incentive offers for the installation of home improvement measures in single family homes. The installation of the measures is performed by a trained and certified PowerShift Energy Advisors and will further enhance the value proposition when implemented in combination with in-home energy assessments and smart thermostat offerings. The measures are intended to introduce customers to products available in the market, which reduce the associated costs of energy consumption.

In the Grid Value portfolio, the Program will expand its DSM savings potential by also providing incentives for grid value measures that enhance both energy savings and DR capabilities.

The **Home Energy Saver program** targets residential end uses with high energy use, including appliances and electric plug loads, and those that are expected to grow rapidly.

The program, through partnerships with participating retailers, will be delivered to customers at the point of purchase as instant product discount. Combining all non-heating and cooling equipment rebates into one program improves the customer experience, increases overall equipment eligibility awareness and streamlines the residential rebate process.

In the Grid Value portfolio, NV Energy's Home Energy Saver program will also integrate_technologies that facilitate both energy savings and demand response capabilities like grid-connected controls, smart appliances, and pool pump controls, as well as promoting easy enrollment in the residential demand response program.

The **Residential AC and Heat Pump Program** is a new standalone program that includes offering incentives for high efficiency residential air conditioning and heat pump retrofits as well as for tune-ups. The rationale for separating this from the Home Energy Saver program is to make it easier for stakeholders to interpret the energy and demand savings being claimed by residential HVAC and heat pump retrofits and tune-ups.

In the Grid Value portfolio, the Program will incorporate additional grid value measures and incentives that complement its retrofit and tune-up activities. The Residential AC and Heat Pump Program will coordinate with the Residential DR program to bundle these complementary grid value measures with DR program enrollment.

The **Residential Codes and New Construction program** provides support to the residential new construction market to increase the EE of Nevada homes. Residential customers benefit through lower energy bills, increased comfort, fewer maintenance concerns, and higher resale values.

The Program will have two separate but complementary components. The new construction portion of the program provides builders of single-family homes education, technical assistance and incentives to exceed local building energy codes. The codes portion of the program will provide tools to support local jurisdictions in adopting the state code and for improving energy code compliance.

In the Grid Value portfolio, the program will also integrate load management enabling equipment, such as smart thermostats, grid-connected electric water heaters, connected pool pumps, and battery systems. These connected devices will be packaged to provide new homes with year-round load shifting capabilities.

The **Income Qualified Multifamily** program is designed to encourage multi-family property owners and property managers to install devices in the residential and common areas of their properties to provide energy and demand savings and to seek additional opportunities to improve the overall efficiency of multi-family properties. The Program seeks to improve the efficiency of low-income multi-family properties through a comprehensive two-track approach. The first track is designed to target existing buildings, while the second track focuses on new construction.

Multi-family property owners and managers will collaborate directly with a designated Energy Advisor to identify energy saving opportunities, provide necessary customer education, and streamline program participation.

In the Grid Value scenario, the Program will focus efforts to promote load shifting in multi-family properties through the installation and utilization of connected devices like smart thermostats and water heater controls. Participation in DR programs is encouraged to create flexible capacity, and water heating storage capacity allows for pre-heating water and using excess renewable energy on the grid.

The **Qualified Customer Program** is designed to provide energy efficient appliances and products to low-income customers who experience high energy bills due to the costs of operating old and inefficient appliances. In 2025, NV Energy will introduce a Weatherization program track alongside the existing Qualified Appliance Replacement ("QAR") track. This program will provide low-income customers with more flexible options to address their home improvement needs and eligibility criteria. In the Grid Value portfolio, both program tracks are bolstered by an initiative targeting low-income customers to help optimize their energy usage by shifting their energy consumption to off-peak periods, thus reducing household bills under TOU rate plans.

In the Grid Value portfolio, the program is bolstered by an initiative targeting customers to help optimize their energy usage by shifting their energy consumption to off-peak periods, thus reducing household bills under TOU rate plans. This effort includes installing connected smart thermostats and providing comprehensive educational support for load shifting.

The **Demand Response Program** ("DR Program") goal is to recruit customers into an ongoing effort that allows NV Energy to interact with air conditioners, end-use loads, or distributed energy resources during times of peak energy use. This is accomplished through DR events in which devices controlling customers' end-use loads receive signals from utility demand response systems to reduce energy consumption. These events shift a significant amount of energy consumption outside of peak demand hours. In return for participation in these events, the DR Program delivers a package of enabling technologies that help customers save energy and money all year round.

The Program is divided into two components: the Build portion, that recruits the participants, and the Manage portion, that maintains and retains the participants.

In the Grid Value portfolio, the Program will also focus on scaling its non-thermostat flexible load resources to better optimize the use of and integration of renewable energy and to complement the Program's strong foundation of thermostat resources that provide critical peak load reductions. The Program will coordinate it efforts across the program portfolio to ramp up participation of water heaters, pool pumps, and electric storage as well as providing technical support and recommendations to help customers save money.
Details of each program are provided in the program data sheets.

21. Q. PLEASE DESCRIBE THE PROGRAMS WITHIN BUSINESS SERVICES.

A. Business Services has programs available for the Companies' approximately 165,000 electric commercial and industrial customers. The portfolio of business services is based on the Energy Efficient Schools, Business Energy Services, and Commercial DR programs and is augmented by the Energy Education program.

The **Energy Efficient Schools Program** is designed to facilitate EE and peak demand reduction in public schools and higher education buildings and facilities. The Program offers three types of energy services to school administrators. First, rebates help offset a portion of the first costs associated with efficiency investments for EE projects. Second, strategic energy management services based on operational and behavioral improvements and third, a high level of technical assistance that serves to offset the staffing needs for school's facility management that would be required for administering EE projects.

The Grid Value portfolio will include measures for additional opportunities for schools to benefit from load shifting and peak energy savings to address the unique operating hours of many schools, such as a focus on behavioral-based savings at times that resources may have excess energy.

The **Business Energy Services Program** offers energy efficiency technical assistance and rebates to commercial and industrial customers, promoting investments in energy efficient retrofits, and new construction projects. The Program generates long-term energy savings and peak demand reduction while influencing building owners, managers, architects, engineers, and contractors to realize the benefits of incorporating energy efficiency strategies into their businesses by lowering operating costs and reducing the total cost of ownership.

The retrofit component of the Program offers prescriptive rebates for energy efficient lighting, cooling, motors, commercial kitchens, refrigeration, and miscellaneous energy conservation measures. Additionally, the Program offers custom rebates for measures not covered under the prescriptive rebate. The Program also offers rebates and instant discounts on qualified lighting products at the point of sale for small and medium businesses' energy efficiency projects.

The new construction component of the Program offers rebates for single pieces of equipment, entire systems, and whole buildings. In order for projects to qualify for a rebate, projects must exceed the applicable International Energy Conservation Code ("IECC") or applicable local building code by at least ten percent of the 2009 IECC or five percent of the 2021 IECC.

The Program's Non-Profit Agency Grant component offers qualifying non-profit organizations, 501(c)(3), financial means to implement energy-efficient measures in the form of grants and technical support for identification and installation of energy-efficient measures in new or existing buildings.

In the Grid Value portfolio, the Program proposes to explore increasing incentives for technologies that deliver energy savings, reduce in demand during peak periods, and enable DR capabilities, such as smart thermostats and water heater controllers for small commercial customers and building/energy management systems for large commercial customers. To encourage DR enrollment, the program will also consider offering incentives for customers that agree to enroll in the DR program at the time of their Business Energy Services energy efficiency project installation.

The **Commercial Demand Response program** will recruit and manage customers to participate in the ongoing program, allows commercial customers to use DR smart technology, such as network thermostats, demand limiting technologies, manual DR through emails, and customer-owned technologies with OpenADR 2.0, to interact with customers' AC, commercial energy storage systems ("ESS"), and end-use loads during peak or emergency conditions to reduce peak demands.

This is accomplished through DR events, in which devices controlling customers' end-use loads receive signals from NV Energy's DR systems to reduce energy consumption. These events shift a significant amount of energy consumption outside of the peak demand hours. In return for their participation in these events, the Program delivers a package of enabling technologies that helps customers save energy and money all year round.

The Program is divided into two components: the Build portion, that recruits the participants, and the Manage portion, that maintains and retains the participants.

In the Grid Value portfolio, NV Energy intends to introduce a new incentive structure that features a menu of options that fills gaps in the current Commercial DR offering. The objective of this new incentive structure is to encourage large qualifying customers to participate in the Program and enable customers to choose the options that best align with their company's operations.

Details of each program are provided in the program data sheets.

SECTION IV: TEP PLAN OVERVIEW AND BUDGET

22. Q. PLEASE DESCRIBE THE TEP PLAN FOR THE ACTION PLAN YEARS 2025-2027.

A. Senate Bill 448 (2021) ("SB448") created and outlines certain requirements for the Plan set forth by the Companies, including its incorporation into the Companies' DRP that is a part of the triennial Integrated Resource Plan. The TEP seeks to meet the objectives of SB448 by building a foundation to maximize grid benefits for all customers through managed charging programs and other services that assist customers with shifting EV charging loads to times that are most beneficial to the grid. The TEP also includes an offering to accelerate the development of EV charging infrastructure for low-income customers in Historically Underserved Communities ("HUC").

The TEP covers transportation electrification programs and investments for the years 2025 to 2027, with a total budget of $19,233,000. The Plan includes multiple customer offerings, including the enrollment of 7,985 ports in NV Energy managed charging programs. The Plan also extends NV Energy's work to educate and engage customers and community-based organizations about the benefits of managed charging and transportation electrification generally.

23. Q. HOW IS THE TEP PLAN ORGANIZED?

A. The TEP is organized into eight sections: (1) Overview and Compliance, (2) Plan Objectives and Budget Overview, (3) Education Services & Grants, (4) Program Development and Other Opportunities, (5) Rules and Tariffs, (5) Managed Charging Programs, (7) Cost Recovery & Projected Rate Impact, and (8) 2022-2024 Transportation Electrification Plan Update.

24. Q. HOW WAS THE BUDGET DEVELOPED FOR THE 2025-2027 ACTION PLAN PERIOD?

A. Budgets for each of the Plan's programs were compiled using data from outside consultants, surveys, lessons learned from previous NV Energy programs, prior program delivery expertise, industry standards and community research.

25. Q. HOW IS THE BUDGET DIVIDED BETWEEN COST CATEGORIES?

A. Budgets for the TEP are segmented into five different categories: 1) Education Services; 2) Program Development and Grants; 3) Managed Charging Programs (including MC Manage); 4) Rate Impact and Cost Recovery; and 5) Outside Services Ramp Up. The budget categories include funds for implementation, including administrative costs. Both the Rate Impact and Cost Recovery and Outside Services categories include administrative costs to complete the studies and/or for ramp up services for program launch if needed. The budgets for the segments are as follows: Education Services, $7,385,000; Program Development and Grants, $3,511,000; Managed Charging Programs, $7,887,000; Rate Impact and Cost Recovery, $300,000; and Outside Services, $150,000.

The budget allocation assumes the maximum enrollment and participation in each of the Plan’s programs.

For purposes of developing the budget, the Companies projected a budget split between the operating utilities at a ratio of approximately 70 percent allocated to Nevada Power and 30 percent allocated to Sierra.

SECTION V: TARIFFS

26. Q. ARE THE COMPANIES UPDATING THE TARIFF TO CONTINUING THE SCHOOL BUS VEHICLE TO GRID ("V2G") TRIAL?

A. Yes. The Companies request to extend the date of Sierra and Nevada Power's Schedule No. ESB-V2G tariffs. Because of the ongoing work with Nevada school districts for both ERTEP and the previously approved TEP, the V2G trial will continue past the previous end date. The Companies propose a new complete date of December 31, 2027.

SECTION VI: TEP PLAN PROGRAMS

27. Q. PLEASE SUMMARIZE THE TEP PLAN PROGRAMS.

A. The TEP proposes a portfolio of Managed Charging programs for both Residential and Non-Residential customers. The TEP builds on NV Energy's core objectives of first, educating customers about the importance of shifting customers' EV charging to times of high renewable energy production and lower overall energy demand; second, managing customer charging and its impact to the electrical grid; third, advancing NV Energy's existing transportation programs and tariffs; and fourth, using data from ongoing program execution to learn and improve program design for future plans.

28. Q. WHAT METHODS DID THE COMPANIES USE TO HELP INFORM PLAN AND PROGRAM DESIGN?

A. To help prepare this Plan, stakeholder feedback was collected through multiple channels. Working group meeting were held quarterly from the beginning of 2023 to April of 2024 to share information and gather feedback on potential Plan inclusions. In addition, NV Energy conducted a survey of TEP stakeholders to derive priority topics that the group should focus on. Seventeen organizations responded and participation spanned the labor, government, non-profit, consulting, technology, environmental and health sectors.

Priorities were identified from the working group, the stakeholder surveys and from NV Energy's previous TEP proposals to guide the Plan design.

29. Q. WHAT IS MANAGED CHARGING?

A. Managed Charging is an operational strategy where the utility can communicate with EV infrastructure to impact the flow of electricity to the charger to control load on the electric system at select times. Managed Charging can ensure that EVs are properly powered when needed, while reducing unnecessary burden on infrastructure and supporting a more reliable and resilient grid.

30. Q. HOW WILL MANAGED CHARGING IMPROVE THE OPERATIONAL FLEXIBILITY OF THE GRID?

A. Managed Charging supplements the Plan's multi-faceted approach to operational flexibility with Managed Charging events. Managed Charging events assist to lessen the impact of new EV charging loads resulting from the Plan's programs and increasing levels of EV adoption during times of high energy costs, system congestion, and grid emergencies. Managed Charging provides immediate near-term benefits and helps to build a foundation of data and customer feedback for future strategy development. Lessons learned in the EV Managed Charging context during this Plan period will allow the Companies to refine and further develop more effective load control strategies for the plans and program proposed in future Integrated Resource Planning ("IRP") filings.

31. Q. PLEASE DESCRIBE HOW THE MANAGED CHARGING EVENTS WILL BE STRUCTURED.

A. NV Energy will determine the need for Managed Charging events based on projected grid conditions and as needed when the grid experiences an emergency. NV Energy anticipates issuing approximately 40 events per year. Events will typically be issued in the June through September summer months when the grid has historically been constrained or has experienced emergency conditions. However, events will be tested or conducted in the fall and spring shoulder seasons to determine the effective capability to actively shift EV charging to absorb excess renewable energy or to mitigate distribution system congestion. A typical event is expected to last two hours between 3:00 pm and 9:00 pm, Monday through Friday.

Each event will be a throttle down of the charging equipment to a percentage of less than 100. The Company will test various levels of throttle to determine optimal results in each customer class.

32. Q. PLEASE SUMMARIZE EDUCATION SERVICES.

A. Education Services are developed to better inform customers about the value of shifting vehicle charging to maximize the grid and increase awareness of transportation electrification benefits, programs, and services while increasing program participation.

Though education, the Plan endeavors to build and enhance partnerships within the community, market the benefits of “When Charging Matters” through direct advertising and outreach, provide technical services for both residential and non-residential customers, work with Nevada auto dealers to provide information to customers at time of purchase and use technology for EV detection and usage data to assist in creating future programs.

33. Q. PLEASE DESCRIBE THE PROGRAM DEVELOPMENT AND GRANTS PROGRAMS.

A. As the Companies understand the need for data and planning for future programs within this Action Plan Period, the Plan includes budget for the continued research and development of opportunities to use Federal Funding to support new development of EV Programs and to offset the costs associated with future transportation electrification projects in Nevada.

The Companies propose a Program Development program to test products and services for potential inclusion in future offerings. The Program will explore TEP and managed charging strategies by conducting tests of emerging products, technologies or services that may enhance current or future portfolio of programs. The Program focuses on products or services for residential, small, medium, and large commercial for of both Nevada Power and Sierra customers.

There will be three pilots within the Program Development Program that NV Energy is proposing. The first is a Residential Submetering **Residential EV TOU Sub-Metering Pilot** to understand actual home charging data to foster a future EV-Only TOU. The second is a **V2X Pilot** to test and study bi-directional charging at the residential level, and the third is the continuation of a **Vehicle Telematics Managed Charging Pilot** to better understand managed charging working directly through vehicle telematics.

Details of each pilot are provided within the Plan.

Through grants, specifically for Nevada transit agencies, the Companies will provide financial assistance and technical services to assist planning organizations and the Nevada Department of Transportation with a focus on prioritizing projects that electrify transit services in HUC. The Company will have an annual "Funding Request Period" to allow planning organizations to submit proposals to apply for funding.

34. Q. WHAT PROGRAMS ARE INCLUDED IN THE 2025-2027 MANAGED CHARGING PROGRAM?

A. The following managed charging programs are included in the Plan:

4. Residential Managed Charging Program
   a. Single Family Residential Managed Charging Build
   b. Qualified Income Multifamily Managed Charging Build
5. Non-Residential Managed Charging Program
   a. Fleet Managed Charging Build
   b. Workplace Managed Charging Build
6. MC Manage

35. Q. PLEASE DESCRIBE THE PROGRAMS WITHIN RESIDENTIAL MANAGED CHARGING.

A. The Residential Managed Charging Build program focuses on allowing NV Energy to control and shift participating Electric Vehicle Supply Equipment ("EVSE") load and manage peak demand by optimizing the scheduling of charging in response to grid needs. Residential Managed Charging Build is composed of two programs:

Single Family Managed Charging Build and Qualified Income Multifamily Managed Charging Build.

The **Single-Family Managed Charging Build program** allow customers in single family homes to receives incentives for enrollment and payments for participation in the program. Customers can enroll with either existing equipment, Bring Your Own Changers component ("BYOC)," or new equipment.

The **Qualified Income Multifamily program** is specifically for buildings for low-income customers or properties located in HUCs. This program will enable eligible multifamily building owners to enroll and receive incentives toward the deployment of infrastructure to support their charging equipment. Each port then enrolled in the program will be eligible for a participation payment at the end of each year.

Details of each program are provided in the program data sheets.

36. Q. PLEASE DESCRIBE THE PROGRAMS WITHIN NON-RESIDENTIAL MANAGED CHARGING BUILD.

A. NV Energy is planning for two non-residential managed charging programs. One focused on fleet customers and one focused on workplace customers. The workplace and fleet charging programs will offer fleet or workplace owners a one-time upfront enrollment incentive for installing internet-connected Level 2 EV charging stations or DC fast chargers (fleet) in exchange for a commitment to participate in the active managing charging element of the program. Participation in each of these two programs will require adoption of the EVRR TOU tariff for separately metered chargers.

The **Fleet Managed Charging Build program** is for businesses with fleet vehicles. This program will enable eligible fleet managers and businesses to receive incentives toward the enrollment of either Level 2 or DC Fast Charging ports. Customers can enroll with either existing equipment as part of BYOC, or new equipment. Each port enrolled in the program will be eligible for a participation payment at the end of each year.

The **Workplace Managed Charging Build program** is for businesses to allow employees to charge EVs. This program will enable businesses to receive incentives toward the enrollment of Level 2 Charging ports installed for benefit of the businesses' employees. Businesses can enroll with either existing equipment as part of BYOC, or new equipment. Each port enrolled in the program will be eligible for a participation payment at the end of each year.

Details of each program are provided in the program data sheets.

37. Q. PLEASE DESCRIBE MANAGED CHARGING MANAGE.

A. Managed Charging Manage is the portion of the Managed Charging program that serves those customers who have enrolled in the Program in all prior years, regardless of the customer class and charging equipment that enabled them to participate. This component works to retain and service customers, maintain the magnitude of the capacity installed in prior years, and execute a wide range of business processes such as event forecasting, optimization, and execution.

SECTION VII: TEP BENEFITS, COSTS AND RATE IMPACT

38. Q. DID THE COMPANIES CONDUCT COST EFFECTIVENESS TESTING ON THE TEP MANAGED CHARGING PROGRAMS?

A. Yes, although not required, the Companies conducted benefit cost testing, using both the Ace Guru model and the DSMore model, on the Plan to provide some additional context around the costs of the programs. The proposed Managed Charging programs achieved a Net Energy Benefits Total Resource Cost ("NTRC") of 3.15 via the Ace Guru model and will provide more than $24.4 million in benefit to customers for the life of the measures. Through the DSMore tool, the programs achieved a NTRC of 3.00 and will provide more than $22.7 million in benefit to customers through the life of the measures. Details of each of the cost benefit tests are provided in TEP Technical Appendix 4.

39. Q. HOW DO THE COMPANIES PROPOSE TO RECOVER THE COSTS ASSOCIATED WITH THE PLAN?

A. NV Energy seeks approval of the creation of a regulatory asset, with carrying charges, to capture the Plan costs incurred before and between future rate cases. The costs will be recorded in the service territory in which the work is performed or allocated.

40. Q. HAS A RATE IMPACT STUDY BEEN PERFORMED THAT INCLUDES THE PLAN'S PROGRAMS?

A. Yes. The Companies conducted a rate impact analysis of the programs. The final analysis shows a maximum annual rate of approximately $0.00030 per kilowatt hour ("kWh") for residential customers at Nevada Power and $0.00013 per kWh at

Sierra. Smaller impacts are seen for other major rate classes. This impact is calculated based on the TEP receiving the requested regulatory asset treatment.

In addition, the Companies analyzed the rate impact without the requested regulatory asset treatment. The final analysis shows a maximum annual rate of approximately $0.00036 per kWh for residential customers at Nevada Power and $0.00024 per kWh at Sierra. Smaller impacts are seen for other major rate classes.

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

A. Yes.

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

EXHIBIT GRANT-DIRECT-1

STATEMENT OF QUALIFICATIONS

ADAM GRANT

NEVADA POWER COMPANY d/b/a NV Energy
SIERRA PACIFIC POWER COMPANIES d/b/a NV Energy
6226 W. Sahara Ave.
Las Vegas Nevada 89146
(702) 402-2183

Professional Experience

2022 to Date — **Director, Electrification and Energy Services**
NV Energy

As Director, Electrification and Energy Services, provides direction for the development, design and delivery of electrification and energy services customer programs which include energy efficiency and demand side management programs, renewable energy programs, economic recovery transportation electrification programs, and transportation electrification programs.

2015-2022 — **Manager, DSM Program Delivery**
NV Energy

Managed delivery of all Sierra Pacific Power and Nevada Power Companies' electric and gas DSM programs. Manage implementation of integrated programs with duties that include oversight of implementation contractors and vendor contract negotiations, overall portfolio and program budget management, and day-to-day program operations. A member of the DSM planning team responsible for designing future DSM programs.

2009-2015 — **Senior Project Manager, DSM**
NV Energy

Managed energy efficiency programs including Commercial Program, Residential Lighting Program, and Second Refrigerator Recycling Program for Sierra Pacific Power and Nevada Power Companies. Prepared all necessary inputs for the Sierra Pacific and Nevda Power regulatory filings including program data sheets for Integrated Resource Plans, DSM Annual Electric and Gas Report Updates.

2007-2009 — **Media Specialist, Corporate Communications**
NV Energy

Media Strategist for both Sierra Pacific Power and Nevada Power Copmpanies. Assisted in creating branding and marketing strategy and performed tasks and interviews as the Companies' spokesman.

Education

Bachelor of Arts in Law & Society, University of California at Santa Barbara, 1992

Boards and Honors

Certified Energy Manager, 2014

Association of Energy Service Professionals, member

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, ADAM GRANT, 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: May 31, 2024

ADAM GRANT

CHRISTOPHER BELCHER

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05___

Prepared Direct Testimony of

Christopher Belcher

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

A. My name is Christopher Belcher. I am the Integrated Energy Services ("IES") Policy and Compliance Manager 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, "NV Energy" or the "Companies"). My business address is 6226 West Sahara Avenue in Las Vegas, Nevada. I am filing testimony on behalf of NV Energy.

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

A. My professional experience includes more than 12 years in the utility industry. I have a Master of Science in Electrical Engineering. I have been employed by NV Energy since January 2011. Prior to my current position, I held positions in Electric Metering Operations, Demand Side Management ("DSM"), Renewable Energy Programs, and Integrated Grid Planning. My statement of qualifications is attached as **Exhibit Belcher-Direct-1**.

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

A. As the IES Policy and Compliance Manager, my responsibilities include managing NV Energy's DSM filings, energy efficiency and conservation ("EE&C") filings, clean energy ("CE") program filings, transportation electrification ("TE") program filings, required compliance items for DSM, EE&C, CE, TE plans and Commission directives resulting from these filings or any NV Energy filings that require DSM, EE&C, CE, TE contributions.

4. Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?

A. Yes, I have testified in proceedings before the Commission in Docket Nos. 21-05012, 22-06014, 22-07004, 23-02001, 23-06007, and 24-02026.

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

A. My testimony, along with the testimony of Companies' witness Patricia Rodriguez and Adam Grant, supports NV Energy's recommendation that the Commission accept its Demand Side Management Action Plan ("Action Plan") for program years 2025-2027.

I also request that the Commission approve the evaluation, measurement and verification reports for the 2023 program year. Together with witness Robert Oliver, I sponsor the measurement and verification ("M&V") reports contained in Technical Appendices DSM-11 through DSM-23.

Additionally, I request that the Commission approve NV Energy's Net-To-Gross Study ("NTG Study") for the 2025 through 2027 program years. Together with witness Lark Lee, I sponsor the NTG Study results in the DSM Plan and provided in Technical Appendices DSM-5 and DSM-6.

Finally, I request that the Commission find NV Energy has completed the required Directives of the Commission's order in Docket Nos. 22-07004 and 23-06044.

6. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?

A. I am sponsoring the following Exhibits:

Exhibit Belcher-Direct-1 Statement of Qualifications

7. Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. In Section I of my testimony, I summarize the M&V results of the 2023 DSM program year, including the verified low-income expenditure results. In Section II, I summarize the cost-effectiveness models that were used to test the proposed DSM programs for the years 2025 through 2027. In Section III, I summarize the NTG Study results that were used in the cost-effectiveness tests and DSM program development. Last, in Section IV, I address certain directives from Docket Nos. 22-07004 and 23-06044.

SECTION I: SUMMARY OF 2023 PROGRAM YEAR M&V RESULTS

8. Q. PLEASE DESCRIBE THE PROCESS NV ENERGY USES TO MEASURE AND VERIFY ENERGY SAVINGS ACHIEVED THROUGH THE IMPLEMENTATION OF DSM PROGRAMS.

A. NV Energy's M&V process for DSM programs uses systematic measurements and analysis to document energy and demand savings achieved by each program and to determine if each DSM program's energy and demand savings goals were achieved. The work is performed by an independent, third-party M&V evaluation contractor, ADM Associates, Inc. ("ADM"), experienced in applying generally accepted industry standards and procedures. The M&V reports quantify the energy savings and demand reduction resulting from the installation of measures and customer participation in the DSM programs. The verified savings are one input into the models used to determine the cost-effectiveness of the DSM portfolio. NV Energy also utilizes the verified savings to monitor the performance of each DSM program and identify opportunities to enhance them. The engineering methods and technical data provided by ADM validate program and portfolio results that provide a basis for benchmarking and comparing NV Energy's DSM programs against those of other utilities.

As part of performing the M&V evaluation, ADM selects random control group samples of completed customer site projects, which allows for the determination of energy savings to be made with plus or minus 10 percent precision and a 90 percent confidence level. A more technical description of the M&V process is provided in the Direct Testimony of Robert Oliver and in the overview of the detailed M&V process provided in Technical Appendices DSM-6 and DSM-7.

The M&V reports for the 2023 program year are provided in Technical Appendices DSM-13 through DSM-23. NV Energy requests that the Commission approve the M&V reports in compliance with Nevada Administrative Code ("NAC") § 704.9522.

9. Q. PURSUANT TO NRS § 704.741(3)(b), DID NV ENERGY EXPEND AT LEAST 10 PERCENT OF ITS 2023 TOTAL DSM PORTFOLIO ON EXPENDITURES DIRECTED TO ITS LOW-INCOME HOUSEHOLD CUSTOMERS AND RESIDENTIAL AND SCHOOL CUSTOMERS LOCATED IN HISTORICALLY UNDERSERVED COMMUNITIES ("HUCs")? [1]

A. Yes. NV Energy expended a total of $6,984,279, or 11.9 percent, on low-income households and residential customers and public schools in HUCs, based on total DSM Portfolio expenditures of $58,510,440. The 11.9 percent of DSM expenses includes spend in two categories: (1) the standalone Qualified Appliance Replacement ("QAR" or also known as "Low-Income") program; and (2) increased incentive levels in all other programs, where possible, for qualified low-income household and HUC participants. For the standalone QAR program, NV Energy expended $3,746,577. For all programs other than the QAR program, a combined $3,702,155 was spent on low-income and historically underserved community participants during program year 2023. These other programs offered measures like residential air conditioning, Direct Install and Home Improvement appliances, Energy Smart Schools teaching in historically underserved communities, Energy Assessments, Residential Demand Response, and Energy Education Kits.

10. Q. PLEASE SUMMARIZE HOW NV ENERGY ATTRIBUTED LOW-INCOME AND HISTORICALLY UNDERSERVED COMMUNITY EXPENSES IN ITS OTHER DSM PROGRAMS.

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[1] "Low-income household" as defined in NRS 704.78347, and "HUC" as defined in NRS 704.78343.

A. ADM Associates used the methodology described in Q&A 20 of Robert Oliver's testimony to identify a list of known qualified low-income and HUC participants and identify their participation elsewhere in the other programs. ADM Associates' analysis was used to calculate the other DSM programs' expenditures that were attributed to low-income and HUC participants presented in Technical Appendix DSM-25.

SECTION II: SUMMARY OF 2023 AND 2025-2027 COST-EFFECTIVENESS TESTS AND COST-EFFECTIVE TEST MODEL

11. Q. PLEASE DESCRIBE THE SIX GENERALLY ACCEPTED COST-BENEFIT TESTS USED TO DETERMINE THE COST-EFFECTIVENESS OF ENERGY EFFICIENCY PROGRAMS.

A. There are six generally accepted basic cost-benefit tests used to compare demand and supply management alternatives. Each test represents a measure of cost-effectiveness from a distinct perspective. The tests are (1) Non-energy benefits Total Resource Costs ("NTRC"), (2) Total Resource Costs ("TRC"), (3) Rate Impact Measure ("RIM"), (4) Utility Cost Test ("UCT"), (5) Participant Cost Test ("PCT"), and (6) Societal Cost Test ("SCT").

12. Q. WHICH COST-EFFECTIVENESS TEST IS NV ENERGY EMPLOYING FOR ITS DSM PORTFOLIO ACTION PLAN PERIOD 2025-2027.

A. NV Energy is relying on the NTRC as its primary cost-effectiveness test, which includes non-energy benefits, pursuant to NAC § 704.934(6).

13. Q. WHICH COST-EFFECTIVENESS MODELS DID NV ENERGY USE TO EVALUATE THE COST-EFFECTIVENESS OF THE DSM PROGRAMS?

A. NV Energy provides cost-effectiveness results from the Ace Guru model that was approved as the default model by the Commission.[2] In parallel, NV Energy provides results from a recently acquired model, DSMore. A more in-depth review of the DSMore model will be offered to stakeholders starting this summer. For more information regarding NV Energy's proposal to use DSMore as the default model in the future, please refer to the testimony of Michael Brown. For more information about the technical aspects and capabilities of the model, please refer to the testimony of Dr. Kenneth Skinner.

SECTION III: SUMMARY OF 2025-2027 NET-TO-GROSS RESULTS

14. Q. PLEASE DESCRIBE THE RESULTS OF THE 2023 NTG STUDY FOR THE 2025-2027 PROPOSED DSM PROGRAMS.

A. The NTG Study indicates that NV Energy's DSM portfolio of programs continues to influence Nevada Power and Sierra customers to implement energy efficient technologies, improvements, or behavioral changes that they would not have otherwise completed. In summary, the NTG Study reports that the 2023 NTG rates have remained relatively stable compared to the previous 2021 NTG Study. The NTG Study is included as Technical Appendix DSM-2. The NTG rates are presented in Tables DSM-44 and DSM-45 in Section 3 of the DSM Plan. For more details about the NTG technical methodology, please refer to the testimony of Lark Lee.

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[2] Docket 22-07004, November 11, 2022, Order, Attachment A, at 6, para. 10

SECTION IV: NV ENERGY'S COMPLIANCE WITH COMMISSION-ORDERED DIRECTIVES

15. Q. DID THE COMPANIES ASSESS THE RATE IMPACTS OF THE PROPOSED GRID VALUE AND PROPOSED GRID VALUE+20% PORTFOLIOS, AS DIRECTED BY THE COMMISSION IN DOCKET NO. 21-06001?[3]

A. Yes. The Companies modeled the rate impacts of the proposed DSM Grid Value, DSM Grid Value+20%, and Traditional portfolios. Details of this rate impact assessment can be found in Section 3 of the DSM Plan narrative and in Technical Appendices DSM-30 and DSM-31. For any technical details about how the rate impacts were calculated, please refer to the testimony of Sanem Sergici.

16. Q. DID THE COMPANIES ASSESS THE IMPACT OF ACHIEVING LESS THAN THE PLANNED LEVELS OF DEMAND SIDE MANAGEMENT, INCLUDING THE IMPACT ON UTILITY REVENUE REQUIREMENT AND AVERAGE COSTS PER KILOWATT-HOUR, AS DIRECTED BY THE COMMISSION IN DOCKET NO. 23-06044?[4]

A. Yes. This assessment can be found in Section 3 of the DSM Plan narrative and Technical Appendix DSM-32. The Companies created another DSM portfolio, labeled as the "Directive 5 DSM Portfolio," which models the scenario where the proposed DSM Grid Value portfolio does not spend all of its budget and does not achieve its savings targets. To determine an amount of underperformance to model, the Companies used the amount of underperformance that occurred during the 2023 DSM program year. In 2023, the DSM programs spent approximately 92 percent of its budget and achieved approximately 88 percent of its planned energy savings.

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[3] Docket No. 21-06001, December 28, 2021, Order at 177, para. 10
[4] Docket No. 23-06044, November 2, 2023, Order at 7, para. 5

These same spending and energy savings budget-to-actual ratios were then applied to the Grid Value portfolio to create the Directive 5 DSM Portfolio. In other words, the Grid Value portfolio is the baseline, and the Directive 5 DSM Portfolio is modeled to underperform the Grid Value portfolio with 92 percent of its expenditures and 88 percent of its energy savings.

Table Rate Impact-4 in the DSM Action Plan narrative demonstrates the rate impact analysis of the Directive 5 DSM Portfolio against the Proposed DSM Portfolio in effect during the 2025-2027 action plan. For Nevada Power, it shows a maximum nominal average rate impact of approximately $0.0003 per kilowatt-hour ("kWh") (also $0.0002 per kWh when adjusted for inflation) for residential customers and smaller impacts for other major customer classes over the next 10 years. For Sierra, it shows a maximum annual average rate impact of $0.0006 per kWh (or $0.0005 per kWh when adjusted for inflation) for residential customers and smaller impacts for other major customer classes over the next 10 years. Thus, the underperforming Directive 5 DSM Portfolio results in slightly higher rates than the Proposed DSM Grid Value Portfolio.

17. Q. DID THE COMPANIES REEVALUATE INCENTIVE TYPES AND AMOUNTS FOR THE RESIDENTIAL EQUIPMENT AND PLUG LOAD'S HEAT PUMP WATER HEATER MEASURE, AS DIRECTED IN DOCKET NO. 23-06044?[5]

A. Yes. The Companies are proposing to move air conditioning and heat pump measures from the Residential Equipment and Plug Loads Program into their own standalone Residential AC and Heat Pumps program. As proposed, this program would continue to provide mid-stream air conditioning and heat pump equipment

[5] *Id* at 7, para. 6

incentives as instant rebates applied to the purchase of equipment for participants. Details and budgets for this proposed program can be found in Section 3 of the DSM plan narrative and in the Residential AC and Heat Pumps program data sheet in Section 5.

18. Q. WAS A BUDGET OF $25,000 MAINTAINED FOR EDUCATIONAL TRAININGS TO LOCAL GOVERNMENTS AND HOMEBUILDERS ABOUT ADOPTING ENERGY EFFICIENT BUILDING CODES IN SIERRA'S RESIDENTIAL CODES AND NEW CONSTRUCTION PROGRAM, AS STIPULATED?[6]

A. Yes. Sierra maintained a budget of $25,000 for education of local government and homebuilders on the benefits of adopting energy efficient building codes. The 2024 $25,000 budget can be found in Table DSM-20 in Section 2 of the DSM narrative and Table DSM-73 of the Residential Codes and New Construction's program data sheet.

19. Q. HAVE THE COMPANIES RESEARCHED IMPROVEMENTS OR MODIFICATIONS TO SIERRA'S NEW CONSTRUCTION PORTION OF THE PROGRAM AND PRESENTED THE IMPROVEMENTS OR MODIFICATIONS TO THE WORKING GROUP AND IN THE DSM PLAN?[7]

A. Yes. Sierra and its implementation contractor for the Residential Codes and New Construction program created a prescriptive version of its New Construction incentives. Under the prescriptive incentive paradigm, the homebuilders have a selection of measures to consider and will receive a fixed incentive for the measures

[6] Docket No. 23-06044, November 2, 2023, Order Attachment A at 4, para. 4
[7] *Id.* at 4, para. 5

they choose to install. More details can be found in the Residential Codes and New Construction program data sheet in Section 5.

20. Q. WAS FUNDING RELEASED FROM SIERRA'S RESIDENTIAL CODES AND NEW CONSTRUCTION IN 2024 REALLOCATED TO SIERRA'S RESIDENTIAL EQUIPMENT AND PLUG LOADS, DIRECT INSTALL AND HOME IMPROVEMENTS, AND LOW-INCOME PROGRAMS, AS STIPULATED IN DOCKET NO. 23-06044?[8]

A. Yes. Sierra reallocated funding from its Residential Codes and New Construction program to its Residential Equipment and Plug Loads, the Direct Install and Home Improvements, and the Low-Income programs as agreed to. The 2024 program budgets presented in Section 2 of the DSM plan narrative reflect the budgets in Attachment 1 of the approved stipulation in Docket 23-06044.[9]

21. Q. HAVE THE COMPANIES FILED 30-DAY INFORMATIONAL NOTICES WITH THE COMMISSION WHEN CHANGES ARE MADE TO THE DSM PROGRAMS, AS STIPULATED IN DOCKET NO. 23-06044?[10]

A. Yes. The Companies have filed two such informational notices as of May 1, 2024, as Docket Nos. 24-03009 and 24-04025.

22. Q. DID THE COMPANIES ADJUST THE INCENTIVES AND ELIGIBILITY FOR THE AIR CONDITIONING TUNE-UP MEASURES IN THE RESIDENTIAL EQUIPMENT AND PLUG LOADS PROGRAM, AS STIPULATED IN DOCKET NO. 23-06044?[11]

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[8] *Id.* at 4, para. 6
[9] *Id.* at Attachment 1, "2024 Stipulation" tables for Nevada Power, Sierra, and NV Energy
[10] Docket No. 23-06044, November 2, 2023, Order Attachment A at 4, para. 7
[11] *Id.* at 5, para. 8

A. Yes. The air conditioning tune-up measure is available to non-income-qualified participants at an incentive amount of $200. Income-qualified participants are eligible for an incentive amount of $400. Participants may only receive one tune-up every 2 years. Please refer to the Residential Equipment and Plug Loads program data sheet in Section 5 of the DSM Plan narrative for 2023 and 2024 program years, and to the Residential AC and Heat Pumps program data sheet for action plan years 2025 through 2027.

23. Q. HAVE THE COMPANIES REEVALUATED THE INCENTIVES FOR THE HEAT PUMP WATER HEATER MEASURE IN THE RESIDENTIAL EQUIPMENT AND PLUG LOADS PROGRAM AS PART OF ITS DSM PLAN FILING?[12]

A. Yes. The Companies evaluated heat pump water heater measures and their incentives, which are proposed in the Residential AC and Heat Pump program data sheet in Section 5, specifically in the "Residential AC and Heat Pumps Program Incentives/Rebate" subsection. The current 2024 incentives range from $200 to $4,000. The proposed incentives for the 2025 to 2027 DSM Plan period range from $365 to $4,000 dependent on the high efficiency air conditioning equipment being installed and the expected energy savings obtained from installing the measure.

24. Q. HAVE THE COMPANIES INCLUDED INFORMATION ABOUT HEAT PUMP WATER HEATER MEASURES AND FEDERAL TAX CREDIT OPPORTUNITIES IN THEIR TRAININGS FOR TRADE ALLIES IN THE RESIDENTIAL EQUIPMENT AND PLUG LOADS PROGRAM?[13]

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[12] *Id.* at 5, para. 10
[13] *Id.* at 5, para. 11

A. Yes. The Companies are sharing information about heat pump water heaters and their federal tax credit opportunities in their training materials with trade allies. Please refer to the program data sheets for the Residential Equipment and Plug Loads and the Residential AC and Heat Pumps programs in Section 5, specifically, the "Traditional Scenario Description" part of the "2025-2027 Proposed Implementation and Plan Enhancements" subsection.

25. Q. HAVE THE COMPANIES PRESENTED TO THE DSM COLLABORATIVE WHETHER THERE IS BUDGET AVAILABILITY TO INTRODUCE AN INCENTIVE FOR CONTRACTORS TO SELL CENTRALLY DUCTED AND MINI-SPLIT HEAT PUMPS IN THE RESIDENTIAL EQUIPMENT AND PLUG LOADS PROGRAM?[14]

A. The Companies presented their proposed DSM Plan programs and incentives to the DSM Collaborative on May 22, 2024. The Companies are proposing mid-stream incentives in its Residential AC and Heat Pumps program to reduce the cost of measures at the point of sale. The Companies are not proposing sales commission incentives for contractors due to budget constraints. The Residential AC and Heat Pumps program's measures and incentives that are proposed in the DSM Plan are based on the results of the MPS, cost-effectiveness testing, and program knowledge and design conducted by Tierra. For more information about the proposed program, please refer to the Residential AC and Heat Pump program data sheet in Section 5 of the DSM plan.

26. Q. HAVE THE COMPANIES HOSTED WORKING GROUPS FOR THE PROGRAM DEVELOPMENT, THE DSM SAVINGS GOALS, AND THE FEDERAL FUNDING WORKING GROUPS TO INFORM ITS

[14] *Id.* at 6, para. 12

PROPOSALS FOR THE 2025-2027 DSM PLAN, AS STIPULATED IN DOCKET NO. 22-07004?[15]

A. Yes, the Companies hosted multiple meetings each for the Program Development working group, the DSM Savings Goals working group, and the Federal Funding working group. The content of these meetings is presented in the working group report and presentation slides in Technical Appendix DSM-5. In summary, the working groups solicited input from the working group attendees, conducted focus groups for community-based organizations and businesses to obtain public input and sentiment about utility programs, and early proposals for the Companies' DSM portfolios were presented for comments and feedback. For more information about the policies and development of the Companies' proposals, please refer to the testimony of Patricia Rodriguez.

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

A. Yes.

[15] Docket No. 22-07004, November 14, 2022, Order Attachment A at 6, para. 9

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 reports for DSM, 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

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: May 31, 2024

CHRISTOPHER BELCHER

LARK LEE

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2024 Joint Integrated Resource Plan (2025-2044)
Docket No. 24-05______

Prepared Direct Testimony of

Lark Lee

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. My name is Lark Lee. I am filing testimony on behalf of Nevada Power Company ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and together with Nevada Power, "NV Energy"). I am a Senior Director with Tetra Tech, an energy and environmental engineering firm. My business address is 2600 Laurel Cliff, New Braunfels, Texas 78132.

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

A. I graduated from Trinity University in 1995 with a Bachelor's degree in Economics, Political Science and Spanish, followed by a year as a Rotary Ambassadorial Scholar in Costa Rica. In 1998, I completed my Master's degree in Policy Analysis at the University of Wisconsin-Madison ("UW"). I was employed by UW as a research assistant during my graduate studies and became a full-time UW academic staff member upon graduation. In January 1999, I accepted an Evaluation Analyst position with Tetra Tech (previously PA Consulting Group, previously Hagler Bailly Services). Since that time, I have conducted more than 200 energy efficiency and demand response evaluation studies, presented more than 80 conference papers

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or sessions, participated in expert panels and plenaries, developed and delivered evaluation, measurement and verification ("EM&V") trainings on behalf of the Association of Energy Services Professionals ("AESP") to both utilities and commissions. The majority of evaluation studies included net-to-gross ("NTG") research where thousands of surveys with customers and hundreds of interviews with market actors have been completed. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Lee-Direct-1**.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS A SENIOR DIRECTOR ADVISING ON NV ENERGY'S NTG STUDY.

A. I have managed or served as a technical advisor on NTG studies for NV Energy since 2011. A critically important component of my Senior Director position is to serve as a technical advisor on evaluations managed by my direct reports, such as I have for NV Energy. As a technical advisor, I ensure studies are based on industry-leading methodologies supported with robust data collection and analysis to result in actionable and defensible results.

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

A. Yes. I submitted direct and rebuttal testimony to the Commission in Docket No. 12-06053 (Nevada Power's Integrated Resource Plan) and direct testimony in Docket No. 16-07001 (Sierra's Integrated Resource Plan). I also supported the direct testimony of Carrie Koenig in Docket No. 21-06001 (Nevada Power and Sierra's Integrated Resource Plan). All of my previous testimony to the Commission was as a sponsor of NV Energy's NTG studies.

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

A. Together with NV Energy's witness, Christopher Belcher, I sponsor the NTG study conducted on behalf of NV Energy for its Demand Side Management ("DSM") programs. The NTG Report ("Study") summarizes the results of the NTG ratios for the residential and nonresidential programs. The Study also describes the research and analysis that was performed to determine the results for NV Energy's DSM programs.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring the following exhibit:

- **Exhibit Lee-Direct-1:** Statement of Qualifications

7. Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. In Section II of my testimony, NTG Definitions and Purpose, I define and discuss key terminology and discuss generally accepted guidelines for conducting NTG studies. I also provide background on how NTG studies can be used to manage DSM programs. In Section III, NTG Methods, I present the methods that can be used to conduct a NTG study and describe why particular methods were selected for use in the Study completed for NV Energy. In Section IV, NTG Analysis and Results, I summarize the results of the Study for these programs and discuss the methods put in place to improve the certainty of the results.

8. Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I am sponsoring and defending the Study for NV Energy's DSM programs, provided in this filing in Technical Appendices DSM-5 and DSM-6. Tetra Tech conducted customer and market actor research in 2023 to determine the free-ridership and spillover rates and resulting NTG ratios for NV Energy's DSM programs based on the 2022 historical period. Drawing on these results, the Tetra Tech evaluation team ("Evaluation Team") projected NTG ratios for the 2025–2027 program cycle informed by NV Energy program staff interviews to understand program design changes and benchmarking research of similar programs or measures.

II. NTG DEFINITIONS AND PURPOSE

9. Q. WHAT IS A NTG RATIO AND HOW IS IT USED?

A. A NTG ratio estimates the overall savings attributable to energy efficiency program assistance. The NTG ratio is applied to the gross savings to calculate net savings impacts for a given program or measure. In other words, the NTG ratio allows one to calculate the percent of gross savings resulting from program assistance and quantify net impacts. Most jurisdictions use a NTG ratio that includes free riders as a subtraction to the ratio and spillover as an addition to the ratio. This is also the approach used for NV Energy as shown below:

$$NTG = (1 - \textit{free-ridership}) + \textit{spillover}$$

One can then calculate the net impacts of a program in terms of energy savings by multiplying the gross savings by the NTG ratio to generate the net program savings as follows:

$$\textit{Net Savings} = \textit{Gross Savings} * \textit{NTG ratio}$$

10. Q. PLEASE EXPLAIN THE FREE-RIDERSHIP AND SPILLOVER COMPONENTS OF THE NTG RATIO.

A. A free rider refers to a program participant who would have made some amount of the energy-efficient improvement in the absence of the program. By understanding what a program participant would have done on their own, one can calculate free-ridership as a percent of savings that would have occurred absent the program.

In contrast, a participant may make some amount of energy-efficiency improvement that is not tracked by the program but is a result of their interaction with the program. Spillover quantifies the percentage of these savings' impacts not directly tracked but influenced by the program. Because spillover captures broader market impacts, there is both participant and nonparticipant spillover. To measure participant spillover, program participants are asked if additional equipment has been installed since participating in the program and, if so, what influence the program had on the decision to install that equipment. For nonparticipant spillover, market actors are surveyed to estimate the amount of efficient equipment that has been installed outside of the program and how much impact the program had on those installations.

11. Q. PLEASE DESCRIBE WHY IT IS IMPORTANT TO ESTABLISH A CONSISTENT MEASUREMENT FOR NTG.

A. The consistent measurement of NTG is important for many reasons. It is instrumental in helping the utility as the program administrator, the Commission in its oversight role, and stakeholders vested in energy efficiency to:

- refine program design (e.g., revise offerings when high free-ridership is found);
- improve overall portfolio design and resource allocation (e.g., push the market by incentivizing equipment, practices, or efficiency levels with low free-ridership);
- understand the extent of market transformation; (e.g., gain insight from spillover on how the program is impacting participant and market actor behavior); and

- calculate program and portfolio cost-effectiveness based on net impacts, which helps align financial interests with societal interests.

NV Energy and the Commission have recognized the value of NTG research as demonstrated through periodic NTG studies since 2011. An added benefit of this commitment is trend analysis, which can be found in the Study. Trend analysis of NTG values allows both the utility and the Commission to gauge how the programs continue to respond to evolving markets. To support this benefit, the Evaluation Team used methods consistent with prior studies as applicable across NV Energy's DSM programs.

12. Q. PLEASE DESCRIBE THE VALUE OF MEASURE LEVEL NTG VERSUS A PROGRAM LEVEL NTG.

A. The most useful aspect of NTG research is insight on the effectiveness of program design by understanding how programs are influencing the implementation of projects. Programs vary based on technologies or measures they offer. The measure level NTG helps assess if measures are being incentivized that, for the most part, would not have happened without the program. For example, within the Home Energy Saver's Residential High Efficiency Air Conditioning ("AC") program component, all the project AC tune-ups occurred because of the program, whereas 71 percent of the incentivized AC equipment were attributed to the program. While care should be taken when interpreting measure-level results because they are based on fewer responses, they do provide insightful qualitative information.

A program's influence can also vary based on how the program is delivered and the customer segment participating. For example, a small business customer is generally less likely to implement energy efficiency than a large customer with a dedicated energy manager. This range of NTG based on customer segments served can be seen in the NTG ratios across the Business Energy Services ("BES") program. The direct install component of the BES program serving small businesses had a high NTG of 96 percent, while the other custom component, which is often comprised of larger, sophisticated customers, had a lower NTG of 58 percent.

13. Q. HOW DO YOU DEFINE THE POPULATION OF INTEREST IN NTG RESEARCH?

A. While participating customers and market actors are the subject of the research to understand how the program influenced their decision-making, the population of interest in NTG research is the program's energy savings. To represent savings, participant-level results are weighted based on project savings implemented through the program. These individual savings results are rolled up to the measure strata-level. Strata-level measure results are then weighted to represent the overall program population savings as shown in Appendix D of Technical Appendix DSM-6.

III. NTG METHODS

14. Q. PLEASE EXPLAIN HOW THE STUDY PLAN WAS DEVELOPED FOR THE NTG RESEARCH FOR NV ENERGY'S DSM PROGRAMS.

A. The Study was based on industry-standard methodologies that also informed prior NV Energy NTG studies. The prior NV Energy methodologies were developed largely based on the free-ridership and spillover methodologies used in Wisconsin, Pennsylvania, and California. These methodologies are referenced in the

Department of Energy's ("DOE") Uniforms Methods Project ("DOE UMP"),[1] which DOE developed to have a set of industry-standard practices for NTG measurement. Tetra Tech was a contributing author of the DOE UMP NTG protocol.

The Study was designed to achieve a target of 90 percent precision within a ten percent confidence level for estimates based on primary data collection with participating customers and market actors. Confidence intervals are one way to represent how "good" an estimate is; the larger a confidence interval for a particular estimate, the less certain we are in the point estimate. Program evaluations routinely employ 90 percent confidence plus or minus 10 percent as the industry standard. For new programs or measures where primary research was not possible, benchmarking research across peer offerings was conducted. The Study is intended to provide NV Energy, the Commission and stakeholders a reliable assessment of the NTG ratios for each DSM program.

15. Q. PLEASE SUMMARIZE GENERALLY ACCEPTED GUIDELINES FOR QUANTIFYING FREE-RIDERSHIP AND HOW THEY WERE APPLIED FOR THE NV ENERGY STUDY.

A. Generally accepted guidelines for estimating the NTG ratio include tailoring for how the program is delivered—if the program primarily works downstream with participating customers, midstream with market actors such as contractors, or upstream with market actors such as manufacturers, distributors, and retailers. Industry standard methods to calculate free-ridership based on how the program is

[1] Chapter 21: Estimating Net Savings – Common Practices, Daniel M. Violette, Ph.D. & Pamela Rathbun, The Uniform Methods Project: Methods for Determining Energy Efficiency Savings for Specific Measures, October 2017.

delivered (downstream, midstream or upstream) are described next along with how they were applied in the NV Energy Study.

Downstream participant NTG research methods typically assess the timing, efficiency, and quantity to determine the free-ridership ratio.

- Timing – when a participant would have purchased the equipment in the absence of the program.
- Efficiency – what efficiency level of equipment the participant would have purchased in the absence of the program.
- Quantity – how much equipment the participant would have purchased in the absence of the program.

Timing of installation is always asked. However, efficiency and quantity may apply only to certain types of equipment and quantity may vary based on equipment and/or customer needs. For example, the Evaluation Team did not measure efficiency for smart thermostats as they deliver savings based on how they are implemented. In contrast, ACs are available in various levels of efficiency. In both examples, quantity will vary based on the customer's heating and cooling needs. The participant free-ridership for NV Energy programs delivered primarily downstream to customers was calculated as followed:

*Free-Ridership = (Quantity*Efficiency*Timing)*Influence*

Midstream contractor NTG research methods typically assess the counterfactual and program influence to determine the free-ridership ratio.

- Counterfactual – what would have happened in the absence of the program.

- Program influence – when a participant would have purchased the equipment in the absence of the program.

The counterfactual measures the percentage of a contractor's sales that received an incentive through the program that would not have happened in the absence of the program either because the customer would have kept their old equipment or because the customer would have installed lower-efficiency equipment. Program influence is based on a contractor's rating of the importance of various aspects of the program in their level of marketing and selling energy-efficient equipment. The contractor free-ridership for NV Energy programs delivered primarily through midstream channels was calculated as follows:

Free-Ridership = Average (Counterfactual, Influence)

Upstream distributor and retailer NTG research methods typically assess how the program influenced the promotion, stocking and pricing of efficient equipment to determine the free-ridership ratio.

- Promotion – how influential the program was on various promotional activities.
- Stocking practice – how the program influenced stocking practices.
- Pricing – how the discount influenced sales.

The distributor and retailer free-ridership for NV Energy programs delivered primarily through upstream channels was calculated as follows:

Free-ridership = 1 - Average (Promote, Max (Stock or Price))

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16. Q. WHAT IS THE PRIMARY RESEARCH METHOD TETRA TECH USED TO ASSESS NV ENERGY'S NTG RATIOS?

A. To estimate NTG ratios for the majority of NV Energy's portfolio savings, Tetra Tech used rigorous and standardized self-report approach ("SRA") survey questions with participants and influential vendors and SRA interview questions with midstream and upstream market actors as discussed on the DOE UMP. The SRA approach relies on participants' reports of what they would have done in the absence of the program and how the program influenced their behavior. For programs that included both downstream and midstream program activity, the Evaluation Team considered reports from both participants and market actors. Tetra Tech advocates an SRA approach for estimating NTG for most program designs. SRA provides both reasonable estimates of NTG and understanding of program attribution that can inform continuous improvement in program designs as discussed above.

17. Q. WERE ANY OTHER GUIDELINES AND RESEARCH METHODS USED?

A. Additional guidelines were used for the Residential Codes and New Construction program. This program was added to NV Energy's DSM portfolio after the last NTG study, which necessitated a methodology tailored for this type of program. The previously referenced California framework addresses this type of program. In addition, the Evaluation Team referenced the methodology used for a similar program implemented by Xcel Energy[2] in developing the NTG. As for all other programs with primary data collection, the Study used an SRA approach. For the

[2] *See:* EMI Consulting, Xcel Energy MN Efficient New Home Construction Product Impact & Process Evaluation, February 21, 2020.

Residential Codes and New Construction program, the Evaluation Team interviewed participating builders and raters, responsible for inspecting homes, in the Nevada Power territory. There were no participants in the Sierra territory in 2022. Due to lack of participation in the Sierra territory, the New Construction activities were paused for program years 2023 and 2024. The Evaluation Team used results from the Nevada Power territory and benchmarking to recommend NTG for Sierra.

18. Q. WHEN DID THE STUDY RELY ON BENCHMARKING RESEARCH INSTEAD OF PRIMARY DATA COLLECTION WITH NV ENERGY'S PARTICIPANTS?

A. The Evaluation Team used benchmarking to stipulate NTG values for new programs or technologies, programs with limited participation, or offerings with a substantial established body of NTG research such as for low-income customers. Benchmarking draws on evaluation research in other jurisdictions for similar programs, measures, or customer segments. Benchmarking is an alternate, cost-effective method to stipulate a reasonable NTG value when an SRA approach is not feasible or there is limited value in primary data collection.

19. Q. PLEASE DESCRIBE HOW THE STUDY ADDRESSED ISSUES WITH PARTICIPANTS' ABILITY TO RECALL DECISION PROCESSES THROUGH ITS SURVEY METHODS.

A. Timing of the interviews for estimating both free-ridership and spillover is often a concern. First, there is the potential for recall bias and the participant's inability to recollect their intentions. Second, the participant (decision-maker) may no longer be available if the survey is conducted long after the project is completed. To minimize these issues, the Evaluation Team conducted research with the most recent program year participants.

There were a few participant projects where the decision-maker was no longer available; this situation can occur with any study. In these situations, the Evaluation Team attempted to identify the project's next most knowledgeable person. If it was not possible to identify anyone who had knowledge of the project, the Evaluation Team did not complete a survey for that project.

20. Q. HOW DID TETRA TECH DETERMINE THE NUMBER OF PARTICIPANTS TO INCLUDE IN THE SURVEYS?

A. When participation numbers were large enough that a census sample was not required, the sampling plan was designed to achieve a minimum of 90 percent at a ten percent level of precision at the program level.

21. Q. HOW DID TETRA TECH DEVELOP AND DESIGN AN OBJECTIVE SURVEY?

A. Objective analysis begins with well-designed questions; biases can be introduced from the beginning with poor question-wording. The Evaluation Team includes highly experienced social researchers with several decades of experience designing surveys to avoid this type of bias. The Evaluation Team researchers also worked on designing and critically reviewing NTG series of questions employed in other states. As a result, Tetra Tech is familiar with the issues inherently prevalent in NTG studies, such as self-report bias and mitigating those issues (e.g., adding consistency check questions).

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Although the analysis relies extensively on quantitative data, the Evaluation Team also uses qualitative open-ended results to verify and, if necessary, recalculate the NTG results. The use of these qualitative data and quantitative consistency check data mitigates the potential for biased results. The review process includes having Tetra Tech senior consultants conduct the consistency check review. The process increases the objectivity of the analysis as it requires agreement on the final results. Data records where there is too much inconsistency between respondent responses, are removed from the analysis.

22. Q. DID TETRA TECH ADJUST ANY NTG RATIOS BASED ON THE CONSISTENCY CHECKS JUST DESCRIBED?

A. While in almost all cases the Study's quantitative NTG values concur with the consistency questions, the Evaluation Team adjusted six scores based on responses for the BES program components. For these six scores, the customers reported the program "had little or no influence" on their decision. Therefore, the Evaluation Team reduced the calculated NTG value by one-half based on this consistency check. The six cases were a mix of Nevada Power and Sierra customers with energy-efficient lighting projects.

IV. NTG ANALYSIS AND RESULTS

23. Q. PLEASE DESCRIBE NV ENERGY'S FINAL PROGRAM YEAR 2022 NTG RESULTS.

A. Tetra Tech's Study presents the NTG results by program and territory, when possible. The overall findings are documented in Technical Appendix DSM-5 and DSM-6, including the methods used to calculate the findings for the downstream, midstream, and upstream programs and sources used in the benchmarking research.

The NTG research for NV Energy's DSM portfolio indicates that the programs continue to influence customers and trade allies to install energy-efficient technologies or improvements that they would not have otherwise done. The majority of savings associated with the programs would not have happened without the programs. Overall, at the service territory level, the NTG rates suggest that most programs have been more influential in Nevada Power's than in Sierra's service territory. While the programs' NTG rates varied, the primary data collection found all were at or above 0.70 with the exception of Energy Smart Schools equipment in Sierra's territory (0.64) and Residential Codes and New Construction in Nevada Power territory (0.59). Even for these two lower scored programs, the majority of savings are still attributable to the programs. Residential Direct Install and Home Improvements had the highest NTG ratios at or close to 1.0 in both service territories.

The Evaluation Team also researched NTG results for similar programs from other utilities and program administrators across the country through a literature review (benchmarking). These findings were summarized and compared with NV Energy's results. There are many reasons for variations in benchmarked NTG results, including (1) methods employed to assess NTG, (2) characteristics of the population served, (3) program design differences, and (4) program maturity. However, despite these potential variations, in all cases, the NTG results calculated for NV Energy were in line with other studies across the nation.

The Study's healthy NTG results, trend analysis of NTG ratios since 2011, and NV Energy program staff interviews support the conclusion that NV Energy has been proactively monitoring markets and making changes to the programs to maximize net savings. NV Energy has employed several successful strategies to keep program attribution high. The strategies include (1) providing a range of assistance to customers or other market actors beyond a financial incentive; (2) working closely and collaboratively with experienced program implementers; (3) having a concerted effort to target the trade ally market through education, training, and networking opportunities; and (4) proactively monitoring baselines and making program changes in response to push the market to install more efficient equipment.

24. Q. PLEASE DISCUSS TETRA TECH'S CONFIDENCE LEVEL OF NV ENERGY'S NTG RESULTS.

A. For programs where Tetra Tech conducted quantitative surveys (Home Energy Saver—Residential High Efficiency AC, Home Energy Saver—Pool Pump Calibration, Residential Direct Install and Homes Improvement, Energy Smart Schools, and BES), participation numbers were sufficient for the Evaluation Team to conduct a random stratified sample of the population except for Energy Smart Schools where a census sample was used. The sampling strategy was to achieve a minimum of 90 percent precision within a ten percent confidence level at the program level as discussed in Section III above in this testimony. The Study reports precision at the program level for both component parts of the NTG rate, the free-ridership and spillover estimates. The confidence interval exceeded 90 percent within a ten percent confidence level for all free-ridership and spillover estimates except for the Home Energy Saver—Residential High Efficiency AC free-ridership estimate, which had a slightly larger confidence interval than planned at 11.5 percent instead of ten percent precision. This was largely due to a clustering of respondents who were either 100 percent a free rider or 100 percent influenced by the program (non-free rider). For Energy Smart Schools, since the Evaluation Team took a census sample, a confidence interval as a sampling statistic does not apply. However, the Evaluation Team is confident in the Energy Smart School results as the surveys represented almost all of the implemented program savings (99.1 percent).

25. Q. WHAT IS THE BASIS OF SCORING FOR THE RESIDENTIAL MIDSTREAM AND DOWNSTREAM PROGRAMS?

A. The approach uses the SRA to ask customers their purchasing intentions in terms of timing, efficiency, and quantity in the absence of the program.[3] The algorithms vary between residential and nonresidential customers as the decision-making process is different. For example:

- The residential decision-making timeframe is generally shorter than with nonresidential customers.
- There tend to be fewer points of contact in the residential customer's decision-making process. For example, residential customers may make the decision themselves or, at most, speak with a contractor. On the other hand, commercial and industrial customers may have engineers, account representatives, technical assistants, corporate standards, etc., that drive their decisions.
- Certain elements of NTG are not as applicable for some residential programs (e.g., efficiency, timing, and quantity).

The downstream and midstream NTG studies addressed the variations in the program designs. The Residential Direct Install and Home Improvements program is a complementary offering to the In-home Energy Assessments program and therefore participants are knowledgeable about how the program influenced their actions. In comparison, the Residential Home Energy Saver's High Efficiency AC

[3] Id.

and Pool Pump Calibration components provide downstream incentives; however, per the program design, these program components are also promoted by market actors (contractors and distributors). Because contractors tend to be an influential point of contact, the NTG approach accounts for the program's influence on contractors' recommendations and sales. The scoring algorithm does this by utilizing contractor responses in the NTG score. Distributor interviews were also conducted for triangulation purposes and confirmed the NTG score from participant surveys that incorporated contractor responses.

For the evaluated downstream programs, the NTG algorithm independently calculated an efficiency, timing, and quantity score for each customer. The combination of these scores is then assessed to calculate the free-ridership rate for that customer. Past participation is also incorporated.

In addition to free-ridership, the Evaluation Team also used the customer survey to determine participant *unlike* spillover for residential customers. Residential customers are not inclined to install more of the same efficiency equipment as they received through the program without also applying for the program incentive, but their experience with the program may influence them to implement other energy efficiency improvements due to education they received and increased awareness. Participant *unlike* spillover is computed based on additional energy-efficiency implemented outside the program because of their experience with the program.

Technical Appendix DSM-6 provides flowcharts that illustrate the algorithms used in calculating program participant free-ridership and spillover for the programs.

26. Q. WHAT IS THE BASIS OF SCORING FOR NONRESIDENTIAL DOWNSTREAM PROGRAMS?

A. Similar to the residential programs, Tetra Tech used an SRA based on the frameworks used in prior studies for the nonresidential downstream programs (BES and Energy Smart Schools). Free-ridership questions follow the California framework with the addition of the Evaluation Team's methodology including a standardized series of questions for prior participation and *like* spillover based on work Tetra Tech developed for Massachusetts and has used for a number of utilities throughout the country.

The standard NTG methodology specified in the California framework uses three primary sources of information to determine NTG: (1) program files and information, (2) participant (decision-maker) surveys, and (3) vendor (participating trade ally) surveys.

The decision-maker survey is targeted at participating customers and asks highly structured questions about actions that would have been taken in the absence of the program. The survey questions for each participant are informed by the information contained in the program files. Respondents are first asked a series of questions to establish project context. They are then asked to rate the importance of *program influences* versus *non-program influences*. Customers are asked to rate the significance of different factors and events that may have led to their decision to install the efficient equipment at the time they did. These factors include questions on the age or condition of the old equipment, type of project, recommendations received, business policies related to equipment purchases, and previous experience with NV Energy programs.

The survey also assessed whether other vendors were influential in customer's decisions, such as trade allies or technical assistants. In cases where the decision-maker stated that the vendor was highly influential in their decision to participate in the program, Tetra Tech attempted to interview the vendor to get their perspective on program influence (these are referred to as "influential vendors").

In addition to free-ridership, the Evaluation Team also used the participant decision-maker survey to determine participant *like* spillover for nonresidential customers. Participant *like* spillover is computed based on how much more of the same energy-efficient equipment the participant installed outside the program because of their experience with the program.

Technical Appendix DSM-6 contains a flowchart that illustrates the algorithm used in calculating free-ridership and spillover for nonresidential customers.

27. Q. DESCRIBE HOW TETRA TECH ADDRESSES NONRESIDENTIAL CORPORATE POLICIES RELATED TO THE PURCHASE OF ENERGY-EFFICIENT EQUIPMENT, SUCH AS FOR NATIONAL CHAINS.

A. Corporate policies are considered a non-program influence in the analysis plan. Essentially, the Study assessed whether corporate policies are relevant for the participating organization and, if so, the level of influence those policies had in their decision to install the equipment rebated through the program. Suppose corporate policies are rated highest among all the non-program influences. In that case, the survey asks participants to rank this non-program influence relative to the program influences (e.g., rebate, the information provided through the program or staff). The calculated NTG ratio reflects the response to these questions; a higher ratio is assigned when more influence is assigned to the program element than other non-program influences, such as corporate policies.

28. Q. PLEASE DESCRIBE HOW TETRA TECH'S ANALYSIS IS AN ACCURATE REFLECTION OF PROGRAM IMPACTS.

A. Net To Gross analysis, particularly analysis that uses self-report data, is often critiqued for its potential lack of certainty. There are several factors that lead to this lack of certainty, including (1) self-report biases, (2) inability for customers to accurately state the counterfactual, (3) time-lapse between program participation or decision-making and the survey, and (4) multiple points of influence that confound the evaluation's ability to identify impacts specifically attributable to program intervention. The Evaluation Team put methods in place to combat these issues and improve the accuracy of results as follows:

- The Evaluation Team strove to fully understand program operations and points of influence on the customers' decision-making process as part of each individual program's study design. It is important in the NTG assessment to understand how the program operates and reaches customers, whether it be through customer-directed advertising, midstream trade allies, or upstream retailers. The Evaluation Team spoke with NV Energy to understand program operations and clarify questions from the data collection and analysis phases. NV Energy program staff also reviewed data collection instruments prior to implementation to ensure the evaluation fully captured staff's involvement. The methodology and resulting NTG algorithms were developed with an understanding of these programs' operations to ensure impacts were most accurately reflected in the results.

- Research was conducted with the most recent historic participants in the program to minimize recall challenges. In addition, the surveys screen to identify the decision-maker for the project and include a number of prompts to accurately remind the customer of their experience with the program.
- Populations were sampled to ensure the sample frame most closely represented the population and that the results reflect differences within the population. Considerable attention was given to the sampling process. End-use stratification was most typically used, although even the end-use stratification can be further refined. For example, the BES program includes many different measures as well as how the program was delivered (i.e., direct install).
- The evaluation approach included several consistency checks. These consistency checks are both closed-ended assessments (e.g., influence scores, changes in plans resulting from participation) and open-ended questions assessing the impact the program had on their decision to install or remove equipment. The Evaluation Team assessed the responses between the consistency data with the resulting NTG ratios and adjusted when appropriate to do so.

29. Q. WHY IS THE EVALUATION TEAM PROPOSING DIFFERENT NTG RATIOS FOR THE KILOWATT AND KILOWATT-HOUR SAVINGS FOR THE DEMAND RESPONSE PROGRAMS?

A. The Residential and Commercial Demand Response ("DR") programs claim both demand (kW) reduction and energy (kWh) savings for the program. The demand (kW) reduction results entirely from events that NV Energy calls during critical peak periods. NV Energy curtails each residential customer's AC usage with smart thermostats or directly reduces commercial customer's load during the event season. Given that program events cannot occur in the absence of the NV Energy curtailment event, one could reasonably conclude that free-ridership is zero. And conversely, one could not reasonably expect customers to implement curtailment activities on their own volition in the absence of the program. Therefore, no NTG adjustment is needed, and an NTG is 1.0 for the demand savings should continue to be applied in line with industry standard practice for demand response programs. This is also the projected NTG for the 2025-2027 DR programs as NV Energy expands program measures to other technologies such as water heaters, pool pumps and energy storage systems.

The program claims energy (kWh) savings from the smart thermostat, which is also a more traditional energy saving measure resulting in annual energy savings as the smart thermostats' algorithms adapt to customers' usage patterns. Therefore, a NTG ratio is applicable for savings outside the curtailment events.

30. Q. PLEASE DESCRIBE HOW TETRA TECH ESTIMATED THE NTG FOR NV ENERGY'S LOW-INCOME PROGRAM, THE QUALIFIED APPLIANCE REPLACEMENT PROGRAM, AND MEASURES TARGETED TO LOW-INCOME POPULATIONS.

A. There is a substantial body of research that shows that low-income households face significant affordability barriers to making energy-efficient improvements. Prior research also supports that a higher percent of low-income households live in older homes with less efficient appliances and equipment. Tetra Tech has conducted primary research with low-income populations that support these conclusions from the body of research. Therefore, the Evaluation Team recommends that a deemed value of 1.0 NTG ratio is correct and appropriate for low-income programs and should continue to be applied. It is standard practice in the industry that low-income programs have a NTG ratio of 1.0, as mentioned in the DOE UMP.

31. Q. PLEASE DESCRIBE HOW TETRA TECH ESTIMATES NTG FOR NEW PROGRAMS.

A. NV Energy provided Tetra Tech the list of programs and measures they were considering, including their upcoming DSM three-year Action Plan period for 2025-2027. If the measure was included in Tetra Tech's existing primary research, the Evaluation Team used the NTG already identified. If the measure was not included in Tetra Tech's primary research, the Evaluation Team used its benchmarking research.

32. Q. PLEASE DESCRIBE TETRA TECH'S ESTIMATED NTG FOR THE ENERGY EDUCATION KITS, ENERGY REPORTS, IN-HOME ENERGY ASSESSMENTS, AND ONLINE ENERGY ASSESSMENTS PROGRAMS.

A. For this type of education and awareness building programs, Tetra Tech recommends a NTG rate of 1.0, as standard industry practice and mentioned in the DOE UMP. This recommendation assumes that the installation rates are included in the gross savings calculations. For the Energy Reports program, energy usage reports are sent to customers to inform them of their usage compared to similar households and encourages them to take actions to reduce energy use. Customers for this program do not choose to opt into the program; therefore, Tetra Tech recommends a NTG ratio of 1.0 for this program.

Likewise, customers do not typically think of doing an assessment unless they need other equipment or if it is a requirement to participate in a program. The In-Home Energy Assessment and Online Energy Assessment programs are delivered as a complementary offering to the Residential Direct Install and Home Improvement program and/or the Residential DR program to deliver a more comprehensive service to customers. The energy assessment identifies areas for improvement that can include both equipment replacement as well as behavior changes. Tetra Tech recommends a deemed 1.0 NTG ratio for the In-Home Energy Assessment and Online Energy Assessment programs as a separate NTG ratio was calculated from primary research for the Residential Direct Install and Home Improvement program; this is appropriate and in line with other jurisdictions.

The Energy Education Kits are targeted to low-income customers and foodbanks, so customers do not proactively seek out participation in the program. See Question 30 above for the Evaluation Team's recommendation of 1.0 for low-income customers.

33. Q. PLEASE SUMMARIZE TETRA TECH'S RECOMMENDATIONS REGARDING NV ENERGY'S NTG RATIOS.

A. I recommend NV Energy use the NTG ratios in the Study to calculate net savings for the upcoming 2025-2027 DSM program cycle. Tetra Tech conducted best practices customer and market actor research in 2023 to calculate the free-ridership and spillover rates and resulting NTG ratios for NV Energy's DSM programs based on the 2022 historical period. The primary research results coupled with NV Energy program staff interviews to understand program design changes and benchmarking research of similar programs or measures informed the Evaluation Team's projected NTG ratios for the 2025–2027 program cycle. When applied to evaluated gross savings, the NTG ratios will result in a reliable estimate of the net savings resulting from the DSM programs.

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

A. Yes.

EXHIBIT LEE-DIRECT-1

Lark Lee, Senior Director

KEY QUALIFICATIONS

Lark has 25 years of experience in the energy industry with particular expertise in EM&V studies with a diverse range of stakeholders. Lark has conducted over 100 research studies of energy efficiency and demand response programs both in the US and abroad. Her expertise includes EM&V frameworks and management, market research, policy analysis, program design, benchmarking and best practices studies, net-to-gross (NTG) research, and process evaluation. Lark is skilled in a number of quantitative analysis methods as well as qualitative research. She is an effective communicator to external audiences, having (1) participated in expert panels, (2) published and presented over 60 research papers or sessions at national conferences, (3) given regulatory testimony, (4) led or presented to collaborative stakeholder groups, and (5) delivered training on behalf of the Association of Energy Services Professionals and at the request of specific utilities.

PROJECT ROLE

Technical director

AREAS OF EXPERTISE

Process evaluation; impact evaluation; NTG estimation; TRM development; market research; statistical analysis and reporting; stakeholder engagement; regulatory support

AFFILIATIONS AND CERTIFICATIONS

Association of Energy Service Professionals (AESP)

YEARS OF EXPERIENCE

25+

EDUCATION

Master of policy analysis, University of Wisconsin—Madison

BA, economics/political science/Spanish, Trinity University, San Antonio, TX

PROJECT EXPERIENCE

Portfolio Net Savings Evaluation of Demand-Side Management Programs, NV Energy 2012, 2016, 2018, 2020, 2023. To inform NV Energy's integrated resource planning, Tetra Tech has led the quantitative free-ridership/spillover studies for NV Energy's demand-side management portfolio of programs in order to accurately estimate net savings resulting from the program since 2012. The Tetra Tech team determined NTG values through rigorous methodologies tailored to program-type. The Tetra Tech team used the most recent prior program cycle research, benchmarking results, and in-depth discussions with NV Energy staff and their implementers about future program design and delivery changes to estimate current NTG values and project NTG values for future programs coupled with recommendations for program improvements. Lark led the 2012, 2016 and 2018 studies and served as a technical reviewer on the 2020 and 2023 studies. These efforts have included presenting to the statewide collaborative group and regulatory testimony supporting NV Energy's program plans and filings.

Statewide Evaluation of Energy Efficiency and Demand Response Portfolios, Public Utility Commission of Texas, 2013-present. Tetra Tech is leading the statewide evaluation effort of Texas energy efficiency and demand response programs across the eight investor-owned utilities, which includes over 100 programs. The EM&V effort documents gross and net energy and demand impacts of the utilities' portfolios; calculates program cost-effectiveness; provides feedback to the Public Utility Commission of Texas (PUCT), utilities, and other stakeholders on program portfolio performance; provides ongoing technical assistance, policy and planning support, and maintains and updates the Texas Technical Reference Manual (TRM) annually. Lark is the project director and primary liaison to the Commission and utilities for this effort, which includes leading statewide collaborative group meetings and working groups to solicit stakeholder input and regularly providing subject matter expertise to both Commission Staff and Commissioners and their staff,

Evaluation, Measurement, and Verification of Energy Efficiency Programs, Entergy Arkansas, Inc., 2016–present. Tetra Tech is conducting EM&V of Entergy Arkansas, Inc.'s (EAI) portfolio of residential, commercial and demand response programs. The effort includes impact evaluation, NTG research, process evaluation, ad hoc analyses, investigations into increasing cost-effectiveness of new measures, providing updates to inputs in the Arkansas TRM and participating in the statewide collaborative group. Lark is leading this portfolio evaluation.

Evaluation of the Nonresidential Smart $aver Custom Program, Duke Energy, 2019–Present. As a subcontractor to Resource Innovation, Tetra Tech is currently leading the process and NTG evaluation of Duke Energy's Nonresidential Smart $aver Custom Incentives program in its Indiana and Carolina territories and previously in Ohio and Kentucky. Lark serves as a technical reviewer, including providing regulatory testimony as needed.

Evaluation, Measurement, and Verification of CPS Energy's Energy Efficiency Programs, 2022–present. As a subcontractor to Frontier Energy, Tetra Tech is conducting evaluation research to support CPS Energy's energy efficiency portfolio. The effort includes impact evaluation, process evaluation and ad hoc research. Lark serves as a technical reviewer.

Residential and Nonresidential Energy Efficiency Programs, Black Hills Energy, 2009–present. Lark served as the project manager and then starting in 2014 technical director for the comprehensive evaluations of Black Hills Energy's energy efficiency portfolios in Iowa, Colorado, and Wyoming. Black Hills is committed to energy efficiency programs that meet energy savings goals and result in high customer satisfaction. A major component of this portfolio evaluation is working with the DSM staff to identify and facilitate the implementation of EM&V recommendations to improve the programs' performance. The EM&V team also provides significant input into program filings and responding to regulatory requests.

Evaluation, Measurement, and Verification Training, Association of Energy Service Providers, 2007–2015. Lark led a team of senior evaluation experts selected by the Association of Energy Service Providers (AESP) to develop and deliver evaluation training to the energy industry. Lark co-developed the training content and delivered numerous trainings to a range of clients, which includes best practices on how to effectively implement impact and process evaluations and conduct NTG research that both estimates net savings and informs continuous improvement in programs to maximize net savings.

SAMPLE OF PRIOR EXPERIENCE

Comprehensive Evaluations of Nonresidential Demand-Side Management Programs, Xcel Energy, 2010–2014. Lark led the evaluations of Xcel Energy's nonresidential programs in Colorado and Minnesota. Tetra Tech worked collaboratively with Xcel Energy to develop rigorous estimates of program gross and net impacts and identify best practices and process improvements to inform future program design. Lark also has provided ad-hoc technical advice as needed to Xcel Energy.

Evaluation, Measurement, and Verification of Pennsylvania Act 129 Residential and Nonresidential Conservation and Demand-Response Programs, West Penn Power (formerly Allegheny Power), 2009-2012. Lark was the project manager of the EM&V efforts for West Penn Power's portfolios in Pennsylvania. One of the aspects of this role was participating in statewide technical working group sessions with Commission staff members, the statewide evaluator, and other Pennsylvania utilities to represent West Penn Power. As part of the acquisition by FirstEnergy, Tetra Tech continues to work on these evaluations as a subcontract to ADM.

Evaluation, Measurement, and Verification of MidAmerican Energy Company's Energy Efficiency Portfolios, 2004-2005, 2012. Lark was the project manager of the 2004-2005 process evaluation of MidAmerican Energy's residential energy efficiency program portfolio. Lark served as a technical advisor on the 2012 evaluation of MidAmerican's complete portfolios in Iowa, Illinois, and South Dakota.

New York Energy Efficiency Programs Process Evaluation, National Grid USA, 2009–2011. Lark led the process evaluations of National Grid's commercial programs in Upstate New York. These included programs targeting small, medium, and large customers and programs with electric and gas savings goals. With aggressive energy savings goals, one of the primary objectives of the evaluation was to provide National Grid with concrete recommendations to achieve the programs' energy savings goals.

Residential Customer Energy Efficiency Program Impact and Process Evaluation, Consumers Energy, 2009–2010. Lark led the evaluation of the residential HVAC and water heating program. One of the objectives of the evaluation was to increase the cost-effectiveness of the program.

Government and Institutional Partnerships Process Evaluation, Southern California Edison, 2007–2008. Lark led the process evaluation of SCE's portfolio of government and institutional partnership programs. The main objective of the process evaluation was to identify program design and delivery improvements.

Efficiency Maine Business Program Evaluation, Maine Public Utilities Commission, 2006–2007. Lark led the first impact and process evaluation of Maine's statewide commercial energy efficiency business program, Efficiency Maine. Evaluators reviewed the energy savings estimates and cost effectiveness of the program and examined the current delivery mechanisms.

Strategic Assessment and Process Evaluation of the Food Services Technology Center, Pacific Gas and Electric Company, 2007. Lark led this evaluation effort that reviewed the effectiveness of the program in achieving its goal of accelerating the adoption of efficient commercial kitchen equipment. The evaluation recommended organizational and managerial changes to increase its performance.

Impact and Process Evaluation of The State of Maryland's Electric Universal Service Program (EUSP), Maryland Public Service Commission, 2004-2006. Lark led the process and impact evaluation of EUSP, which included securely collecting and storing billing data across the different investor-owned utilities. The longitudinal evaluation provided the client with quantitative support of the program's effect on participants' bill payment behaviors and process findings.

Wisconsin Home Energy Assistance and Weatherization Assistance Programs, Public Service Commission of Wisconsin, 2001-2004. Tetra Tech led the evaluation of the statewide public benefits program, Wisconsin Focus on Energy. After working on a number of evaluation studies across Wisconsin Focus on Energy, Lark led the comprehensive, longitudinal study of the statewide home energy assistance and weatherization assistance programs, which resulted in recommendations to increase the comprehensiveness of program services and the percent of eligible population served.

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, LARK LEE, 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 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: May 31, 2024

LARK LEE

ROBERT R OLIVER

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2024 Joint Integrated Resource Plan (2025-2044)
Docket No. 24-05____

Prepared Direct Testimony of

Robert R. Oliver

I. INTRODUCTION

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

A. My name is Robert R. Oliver. I am filing testimony on behalf of 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, "NV Energy"). I am currently a Principal at ADM Associates, Inc. ("ADM"), an independent third-party evaluation, measurement, and verification ("EM&V") contractor that provides consulting services and performs measurement and verification ("M&V") activities and reporting for NV Energy. ADM is providing M&V reports for NV Energy's Demand Side Management ("DSM") Portfolio of programs as part of this filing. My business address is 417 W. Plumb Lane, Reno, Nevada.

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

A. I have a Bachelor of Science in economics and business management from Cornell University. I have been employed by ADM since 2010. I have participated in the independent third-party M&V activities for NV Energy's energy efficiency programs since 2007 and have provided consulting services in various energy efficiency-related assignments since 2005. I was previously a consultant for the

Nevada Task Force for Renewable Energy and Energy Conservation in 2004 and 2005. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Oliver-Direct-1**.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS THE PRINCIPAL-IN-CHARGE OF EM&V ACTIVITIES FOR NV ENERGY'S DSM PROGRAMS.

A. As the Principal-in-Charge of EM&V activities, my responsibilities include analyses, quality assurance and project management tasks on behalf of NV Energy's DSM programs, which include: Business Energy Services; Commercial Demand Response ("DR"), Manage and Build; Direct Install and Home Improvements ("Direct Install"); Energy Assessments, In-Home and Online; Energy Education; Energy Smart Schools; Home Energy Reports; Home Energy Saver; Low Income; Residential Codes and New Construction; and Residential DR, Manage and Build.

I also provide guidance and quality assurance for ADM's development of energy savings curves for NV Energy's DSM programs. Further, I direct and coordinate all EM&V activities and analyses for ADM's cross-discipline team of data scientists, economists, econometricians, engineers, sociologists, statisticians, and other professionals who participate in the independent evaluation of NV Energy's portfolio of DSM programs.

4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION") OR SUPPORTED ADM'S TESTIMONY PROVIDED TO THE COMMISSION?

A. Yes. I previously testified before the Commission in the following dockets:

- Sierra 2011 Annual DSM Update Report: Docket No. 11-07026;
- Nevada Power 2011 Annual DSM Update Report: Docket No. 11-07027;
- Nevada Power 2012 Deferred Energy Accounting Adjustments ("DEAA"): Docket No. 12-03004;
- Sierra 2012 DEAA: Docket No. 12-03005;
- Sierra 2012 Annual DSM Update Report: Docket No. 12-06052;
- Nevada Power 2012 Integrated Resource Plan ("IRP"): Docket No. 12-06053;
- Nevada Power 2017 Annual DSM Update Report: Docket No. 17-06043;
- Sierra 2017 Annual DSM Update Report: Docket No. 17-06044;
- NV Energy 2018 Joint IRP: Docket No. 18-06003;
- NV Energy 2019 Joint DSM Update Report: Docket No. 19-07004;
- NV Energy 2020 Joint DSM Update Report: Docket No. 20-07004;
- NV Energy 2021 Joint IRP: Docket No. 21-06001;
- NV Energy 2022 Joint DSM Update Report: Docket No. 22-07004; and
- NV Energy 2023 Joint DSM Update Report: Docket No. 23-06044.

I have also collaborated with and supported my ADM colleague, Sasha S. Baroiant, with respect to his testimony before the Commission in the following dockets:

- Nevada Power 2013 DEAA: Docket No. 13-03003;
- Sierra 2013 DEAA: Docket No. 13-03004;
- Nevada Power 2013 Annual DSM Update Report: Docket No. 13-07002;
- Sierra 2013 IRP: Docket No. 13-07005;
- Sierra 2014 Annual DSM Update Report: Docket No. 14-07007;
- Nevada Power 2014 Annual DSM Update Report: Docket No. 14-07008;
- Sierra 2015 Annual DSM Update Report: Docket No. 15-06065;
- Nevada Power 2015 IRP: Docket No. 15-07004;
- Sierra 2016 IRP: Docket No. 16-07001; and

- Nevada Power 2016 Annual DSM Update Report: Docket No. 16-07007.

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

A. Together with NV Energy's witness, Christopher Belcher, I sponsor the M&V reports contained in Technical Appendices DSM-13 through DSM-23. The M&V reports provide descriptions and documentation related to all analyses that ADM performed to verify energy (kilowatt-hour or "kWh") savings and critical peak demand (kilowatt or "kW") savings achieved by NV Energy's 2023 portfolio of DSM programs.

I provide a section by section overview of the contents of my testimony in Q&A 7.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring the following exhibit:

Exhibit Oliver-Direct-1: Statement of Qualifications

7. Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. In Section II of my testimony, I describe the work that ADM performs in preparing M&V reports for NV Energy's DSM programs, and I describe the industry standards that guide M&V activities and reporting. In Section III, I address 2023 updates to M&V analyses for residential lighting measures. In Section IV, I summarize 2023 updates to energy savings curves. In Section V, I discuss M&V use of AMI data. In Section VI, I describe M&V findings for the new DR battery storage measure in NV Energy's residential DR program. In Section VII, I summarize ADM's low-income analyses conducted on residential DSM programs. In Section VIII, I address how ADM avoids double counting of savings for cross-participants. In Section IX, I address M&V findings for the Online Energy

Assessments Program, and in Section X, I address M&V findings for the Home Energy Reports Program. In Section XI, I address M&V data collection topics.

II. M&V REPORTS FOR DSM PROGRAMS

8. Q. PLEASE DESCRIBE THE WORK ADM PERFORMS IN PREPARING M&V REPORTS FOR NV ENERGY'S DSM PROGRAMS.

A. ADM collects and analyzes data to independently determine energy savings and demand reductions for NV Energy's DSM programs. Data collection begins with inspection of data entered by NV Energy or NV Energy's program implementers into DSM Central ("DSMC"). DSMC is the data management system used by NV Energy to track participants, measures, energy savings, and demand reductions attributed to each DSM program. The data in DSMC is project-specific, listing customer-descriptive data, energy savings, and demand savings that are recorded at the measure level, whenever practical. After reviewing the DSMC records, ADM collects primary M&V data through various due-diligence activities including the following:

- Inspect and analyze all project documentation for a representative sample of implemented projects;
- Conduct on-site or virtual audits or inspections of a representative sample of implemented projects; and
- Conduct interviews and surveys for a representative sample of program participants.

Through these M&V activities, ADM verifies that the energy efficiency and DR measures recorded in DSMC have been appropriately installed and are being utilized by the customers who participated in NV Energy's programs. ADM also collects the data needed to analyze and calculate energy (i.e., kWh) savings and critical peak demand (i.e., kW) savings. All data collection activities are guided by appropriate statistical sampling procedures.

Using the data collected, ADM calculates and validates annual and monthly kWh savings and critical peak kW savings for each DSM program. M&V analyses are performed using engineering calculations and statistical analyses, as appropriate. The ADM team provides NV Energy with annual reports for programs based on the results of ADM's independent M&V work. NV Energy uses the results of the annual M&V reports to appraise program performance and develop strategies for program improvements. M&V reports are also submitted to the Commission for review.

9. Q. PLEASE DESCRIBE IN MORE DETAIL THE GENERAL INDUSTRY STANDARDS AND SPECIFICATIONS THAT GOVERN THE M&V OF ENERGY AND DEMAND SAVINGS.

A. The success of utility-sponsored DSM activities is closely scrutinized in many regulatory jurisdictions to ensure customer funds are prudently spent and DSM programs are delivering energy savings and demand reductions that are expected by system planners. Independent third-party M&V is an industry standard that is typically a mandatory activity for utilities performing DSM. Standards and specifications that guide M&V activities are set forth in several guidebook documents, including the following:

- EM&V protocols for DSM measures, published through the Uniform Methods Project ("UMP") sponsored by the U.S. Department of Energy ("DOE");[1]

[1] Available at www.energy.gov/eere/about-us/ump-protocols.

- International Performance Measurement and Verification Protocol ("IPMVP"). *Core Concepts*. Efficiency Valuation Organization. October 2016;[2]
- *M&V Guidelines: Measurement and Verification for Performance-Based Contracts Version 4.0*, DOE Federal Energy Management Program ("FEMP"), November 2015; and *Supplement to M&V Guidelines: Measurement and Verification for Performance-Based Contracts Version 4.0*, FEMP, September 2023;[3]
- American Society of Heating, Refrigeration and Air Conditioning Engineers ("ASHRAE"). *Guideline 14-2014: Measurement of Energy, Demand and Water Savings*;[4]
- *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources*, National Efficiency Screening Project, May 2017;[5]
- *Energy Efficiency Program Impact Evaluation Guide*, State and Local Energy Efficiency Action Network, December 2012;[6] and
- *SEE Action Guide for States: Evaluation, Measurement, and Verification Frameworks—Guidance for Energy Efficiency Portfolios Funded by Utility Customers*, State and Local Energy Efficiency Action Network, January 2018.[7]

10. Q. DID ADM FOLLOW INDUSTRY STANDARDS IN PERFORMING THE M&V SCOPE OF WORK REQUESTED BY NV ENERGY?

[2] IPMVP *Core Concepts* may be downloaded at www.evo-world.org by establishing a free account. (Also, a very similar IPMVP version is here: www.eeperformance.org/uploads/8/6/5/0/8650231/ipmvp_volume_i__2012.pdf.)
[3] Available at www.energy.gov/sites/prod/files/2016/01/f28/mv_guide_4_0.pdf and https://www.energy.gov/sites/default/files/2023-09/supplement-to-mv-guidelines_version-4.pdf.
[4] Available at https://www.techstreet.com/ashrae/standards/guideline-14-2014-measurement-of-energy-demand-and-water-savings?gateway_code=ashrae&product_id=1888937.
[5] Available at www.nationalefficiencyscreening.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf.
[6] Available at www4.eere.energy.gov/seeaction/system/files/documents/emv_ee_program_impact_guide_0.pdf.
[7] Available at www7.eere.energy.gov/seeaction/system/files/documents/EMV-Framework_Jan2018.pdf; this EM&V guidance document succeeds and contains references to the California Public Utilities Commission's June 2004 *California Evaluation Framework*.

A. Yes. All M&V work ADM performed in evaluating NV Energy's 2023 DSM programs complies with industry standards. However, the accepted evaluation methodologies described offer various approaches to evaluate a given measure or program and, therefore, it is not possible to concurrently comply with all recommended approaches. ADM selects from available protocols to achieve the most rigorous overall evaluation of a measure under the circumstances.

11. Q. PLEASE SUMMARIZE THE APPROACHES THAT ADM USED TO MEASURE AND VERIFY SAVINGS FOR 2023 PROGRAMS.

A. The taxonomy provided in the *Energy Efficiency Program Impact Evaluation Guide* identifies three major approaches for determining energy savings and demand reduction:

- A **site-specific or project-by-project M&V approach** involves (1) selecting a representative sample of program participants, (2) employing one or more of the M&V options defined in the IPMVP to determine savings for sampled sites or projects, and (3) using standard statistical methods, apply the results for sampled projects to the determination of program-level savings.
- A **deemed savings approach** involves using stipulated savings for well-known energy conservation measures with well-documented savings. For example, this approach may be used for lighting retrofits for common types of spaces (e.g., offices), where there is general agreement on the hours of use for such spaces.
- A **large-scale consumption data analysis approach** involves determining energy savings and demand reduction by applying standard statistical methods to the measured energy consumption, utility meter billing data and independent variable data. This approach (1) usually involves analysis of a census of project

sites versus a sample, (2) may include the use of a control group[8] and (3) typically does not require on-site data collection for model calibration. However, a sample of customers or sites may be selected and visited to verify proper installation and operation of the energy conservation measures.

When performing M&V analyses, ADM examined program documentation to identify (1) the types of energy efficiency measures from which savings are expected to be achieved and (2) which of the three aforementioned analytical approaches is most appropriate for determining savings for a particular measure or program. In choosing the savings estimation approach, ADM takes account of several factors:

- The magnitude of expected savings from a program or measure. In particular, analysis of billing data may not be sufficient to detect savings of small magnitude for some measures.
- The number and complexity of measures and technologies that are promoted through a program. For example, if multiple measures are installed at a single customer site, the measures may cause overlapping or interactive impacts. Identifying impacts of individual measures, therefore, requires using a savings estimation approach that accounts for the impact of interrelated measures.
- Costs associated with the various analytical approaches.

[8] Scientific studies commonly utilize two distinct groups of subjects: a treatment group and a control group (which may also be called a comparison group). Treatment and control groups must exhibit similar pre-study characteristics. As the study commences, all treatment group subjects receive a specific and tangible treatment, e.g., a medical intervention, a behavioral intervention, or an energy efficiency measure. Control group subjects receive nothing of value (but might receive a placebo in a human medical trial); oftentimes, the control group is undisturbed. For a given energy efficiency study that ADM conducts for NV Energy, the treatment group consists of customers who received a specific energy efficiency measure or behavioral intervention. The corresponding control group consists of customers with similar pre-study characteristics who did not receive a measure or intervention. ADM subsequently determines the energy impacts of the treatment by comparing the outcomes of the customers in the treatment group to the undisturbed outcomes of the customers in the control group.

III. UPDATES TO 2023 M&V ANALYSES FOR RESIDENTIAL LIGHTING

12. Q. HOW DID REGULATIONS RESULTING FROM NEVADA ASSEMBLY BILL 54 (2019) ("AB 54") AFFECT M&V METHODS?

A. All light-emitting diode ("LED") bulbs distributed by NV Energy's 2023 Low Income, Direct Install, and Energy Education programs are general service lamps ("GSLs") per AB 54 regulations.[9]

For the LED bulbs distributed by those programs, ADM utilized a dual-baseline methodology that ensures accurate reporting for LED lifetime energy savings, effective useful life ("EUL"), and cost effectiveness. The M&V methodology for the dual baseline is described in the corresponding M&V reports.

Nevada's AB 54 regulations are similar to federal Energy Independence and Security Act of 2007 ("EISA")[10] codes, which provide two tiers of code changes for GSLs:

- EISA 'Tier 1' codes, which started impacting consumers in 2013, limited GSLs to 29W for a 40W equivalent bulb, 43W for a 60W equivalent bulb, 53W for a 75W equivalent bulb, and 72W for a 100W equivalent bulb.[11]

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[9] LCB File No. R100-19, promulgated pursuant to NRS 701.260; for additional information, see https://www.leg.state.nv.us/Register/2019Register/R100-19AP.pdf.
[10] Available at https://www.govinfo.gov/content/pkg/PLAW-110publ140/pdf/PLAW-110publ140.pdf.
[11] Bulb equivalencies (e.g., 40W, 60W, 75W, and 100W) refer to the wattage of traditional Edison incandescent light bulbs.

- EISA 'Tier 2' codes[12] set a minimum GSL efficacy of 45 lumens per watt, limiting GSLs to 12W for a 40W equivalent bulb, 20W for a 60W equivalent bulb, 28W for a 75W equivalent bulb, and 45W for a 100W equivalent bulb.

The AB 54 regulations, which became effective on January 1, 2021, required compliance equivalent to EISA Tier 2. All LEDs distributed through NV Energy's 2023 DSM programs were GSLs, i.e., subject to AB 54 regulations.

13. Q. PLEASE EXPLAIN ADM'S DUAL-BASELINE METHODOLOGY FOR CALCULATING LIFETIME SAVINGS FOR LEDS.

A. In recent years, many EM&V stakeholders have asserted that a dual baseline for LEDs may use EISA Tier 1 savings for approximately three years after Tier 2 begins.[13] The rationale is that EISA Tier 1-compliant halogen GSLs typically have rated lives of three years or more, and 'out-of-code' bulbs such as halogen GSLs may remain available to consumers for a time interval after the new code begins.

NV Energy's 2023 Low Income, Direct Install, and Energy Education programs provided customers ENERGY STAR® certified[14] LEDs that replaced the inefficient GSLs that were in sockets at the time that the GSLs were replaced. Given

[12] According to the EISA statute, its Tier 2 codes were to become effective by January 1, 2020. However, in 2019 the DOE set aside Tier 2 requirements, enabling the lighting industry to disregard Tier 2 codes. Subsequently, on May 9, 2022, the DOE published a final rule implementing EISA Tier 2 codes effective July 25, 2022, in all states that had not previously implemented regulations similar to those required by AB 54 (Federal Register Vol. 87, No. 89, May 9, 2022, at 27439; see www.govinfo.gov/content/pkg/FR-2022-05-09/pdf/2022-09477.pdf). The DOE also published multiple documents indicating that full enforcement would begin August 1, 2023 – see www.energy.gov/sites/default/files/2022-04/GSL_EnforcementPolicy_4_25_22.pdf and www.energy.gov/sites/default/files/2022-05/GSL%20Backstop%20Enforcement%20Webinar%20May%204%202022.pdf.

[13] For example, the Arkansas Technical Reference Manual ("TRM") Version 8.0, authored by the numerous stakeholders in the Arkansas group known as the Parties Working Collaboratively ("PWC"), asserted that, if EISA Tier 2 had taken effect January 1, 2020, then Tier 1 savings would end three years later on December 31, 2022. See Arkansas TRM 8 Vol 2, Page 224, Footnote 347.

[14] The ENERGY STAR lighting database can be downloaded from the following website: https://www.energystar.gov/productfinder/product/certified-light-bulbs/results.

that it is not practical to measure with certainty the remaining useful life ("RUL") of the replaced GSLs, ADM assumed an average RUL of two years. Therefore, for the LEDs that were provided to participants in those programs, ADM used two years for the first part of the dual baseline.

For the second part of the dual baseline, ADM used the EISA Tier 2 baseline (as provided in Q&A #12 above) for the third year through the end of the nominal EUL for each LED model. Nominal EUL, which is the quotient of the LED's rated life and 1,029 hours per year,[15] cannot exceed 20 years, consistent with previously approved M&V methodology.

For example, an 11W A19 GSL[16] LED rated at 1,300 lumens provides similar illumination as a 75W traditional Edison incandescent bulb or a 53W halogen GSL. If the 11W LED has a nominal EUL of 14.6 years (15,000-hour rated life divided by 1,029 hr/yr) and was installed before the end of 2023, annual energy savings and lifetime energy savings are calculated as follows.

- EISA Tier 1 annual savings (Q&A #12 above provides the Watts per LED):
  (53-11) W • 1,029.3 hr/yr. ÷ 1000 W/kW = 43.2 kWh
- EISA Tier 1 baseline applies for two years:
  EISA Tier 1 annual savings of 43.2 kWh times 2.0 years equals 86.4 kWh.
- EISA Tier 2 baseline applies for the rest of the nominal EUL, i.e., 12.6 years:
  (28-11) W • 1,029.3 hr/yr ÷ 1000 W/kW = 17.5 kWh/yr. • 12.6 yr. = 220.5 kWh
- The lifetime kWh savings per LED is 306.9 kWh:
  86.4 kWh (Tier 1) + 220.5 kWh (Tier 2) = 306.9 kWh (lifetime savings)

[15] During September 2014 to April 2015, ADM completed a statewide LED Monitoring Study for NV Energy through which residential LED hours of use ("HOU") was found to be 2.82 hours per day or 1,029 hours/year.
[16] A19 is the most familiar form factor for GSL bulbs; the A19 form is a common, pear-shaped bulb.

A lifetime savings stream derived from a dual baseline does not provide the normal inputs for NV Energy's planning models and forecasting tools (e.g., ACE guru). Thus, to ensure accurate modeling and forecasting, ADM translates the dual baseline into a single, shortened EUL that facilitates accurate ACE guru analyses. Whether for a given energy efficiency measure or a whole DSM program, EUL can be described as the quotient of lifetime energy savings and annual energy savings. Similarly, for a given LED, its shortened EUL is the quotient of lifetime savings and Tier 1 annual savings. For example, the 11W LED described above has a 14.6-year nominal EUL but a shortened EUL of 7.1 years:

- 306.9 kWh lifetime savings ÷ 43.2 kWh/yr. = 7.1 years (shortened EUL).

14. Q. PLEASE EXPLAIN THE M&V METHODOLOGY FOR CALCULATING SAVINGS FOR LEDS INSTALLED THROUGH THE 2023 RESIDENTIAL CODES AND NEW CONSTRUCTION PROGRAM.

A. The 2023 program year was the first full program year for the Residential Codes and New Construction Program (NV Energy began implementing this program in mid-2022). To date, the Residential Codes and New Construction Program has only been implemented successfully in the Nevada Power service area.

For LEDs installed through the 2023 Residential Codes and New Construction Program, ADM employed engineering analyses to determine ex-post verified energy savings per LED. Ex-post savings were calculated using methods consistent with Chapter 6 of the UMP.[17] ADM's calculations used a compact fluorescent lamp

[17] The Uniform Methods Project: Methods for Determining Energy Efficiency Savings for Specific Measures: January 2012 - September 2016 (nrel.gov), https://www.nrel.gov/docs/fy18osti/70472.pdf.

("CFL") baseline, consistent with the 2018 International Energy Conservation Code ("IECC 2018") as amended for southern Nevada.[18]

To determine the per dwelling ex-post verified energy savings for LEDs, ADM assumed an average count of 58 bulbs per dwelling, which is consistent with NV Energy's assertion of an average of "58 sockets per home" in a 2011 DSM Update Report.[19] In ADM's judgement, 58 bulbs per dwelling is a reasonable estimate to be applied to the 2023 Residential Codes and New Construction Program.

IV. UPDATES TO ENERGY SAVINGS CURVES

15. Q. DID ADM UPDATE ITS METHODOLOGY FOR 2023 ENERGY SAVINGS CURVES?

A. There were no substantive changes in M&V methodology in 2023, but energy savings curves were modified incrementally from the previous program year.

ADM's goal is to provide the best possible representation of the program-level and portfolio-level impacts each time a program is evaluated. As DSM programs evolve (e.g., through inclusion of new measures, changes in measure distributions or even changes in code or market baselines), it may be appropriate to update the M&V analysis by developing or selecting optimal energy savings curves that may differ incrementally from previous energy savings curves. ADM is committed to

[18] All dwellings in the 2023 program were permitted under IECC 2018. "Southern Nevada Amendments to the 2018 International Energy Conservation Code," which were adopted by the Clark County Commission on 8/21/2018 with the effective date of 2/4/2019, can be found here: https://webfiles.clarkcountynv.gov/Building%20&%20Fire%20Prevention/Codes/2018_IECC_Amendments.pdf. As of the date that this testimony was prepared, information provided by Nevada Building Officials indicates that southern Nevada jurisdictions are in the process of updating energy codes to IECC 2024, which will take effect in 2025; see https://nevadabuildingofficials.org/current-adopted-codes/.

[19] See page 145 of 390, Docket 11-07026, "Application of Sierra Pacific Power Company d/b/a NV Energy for approval of its 2011 Annual Demand Side Management Update Report as it relates to the Action Plan of its 2011-2030 Integrated Resource Plan," 10144.pdf (state.nv.us).

constantly improving the quality of energy savings curves, which in turn improves the accuracy and precision of M&V determinations.

16. Q. HOW HAVE 2023 ENERGY SAVINGS CURVES BEEN UPDATED?

A. ADM's methodology for 2023 energy savings curves is substantially similar to ADM's approach during the previous 12 years. ADM has developed project-specific curves for sampled projects, while non-sampled projects are represented by measure-market specific curves that are derived primarily from the California Commercial End-Use Survey ("CEUS").

For the subset of commercial projects in the M&V sample for which prescriptive algorithms were employed to determine ex-ante estimated savings ("prescriptive projects"), ADM's methodology for 2023 energy savings curves is the same as the methodology previously described for 2022 energy savings curves:

- ADM applied partially deemed savings when calculating ex-post verified energy savings; criteria used for applying partially deemed savings algorithms are explained in detail in the M&V reports included in this filing; and
- ADM did not use site-specific data to determine energy savings curves; instead, consistent with M&V methodology that has been accepted since 2019, ADM used deemed building type and equipment type curves that ADM developed from historical M&V results for projects that had been sampled in program years 2010 through 2018.

To describe the impacts of Nevada Power's 2023 Business Energy Services Program, ADM used a total of 57 unique curves, of which 22 were project-specific curves derived from primary data collected during M&V; the remaining 35 curves were building type-specific deemed curves developed from historical M&V results.

Similarly, ADM used 33 unique curves to describe the impacts of Sierra's 2023 Business Energy Services Program; of these, 13 curves were project-specific curves derived from primary data collected during M&V, while the remaining 20 were building type-specific deemed curves developed from historical M&V results.

ADM sampled many of the largest and most significant 2023 projects, as these benefit the most from customized energy savings curves. As with previous years, lighting efficiency improvement projects are a key driver of non-residential sector impacts. ADM has used the same site-specific lighting calculator since 2013. For M&V sample sites using custom building hours, the calculator constructs site-specific savings curves while also calculating project-level verified impacts. For those projects that utilize deemed hours, the calculator applies the appropriate building type-specific curve developed from previous M&V results.

17. Q. PLEASE DESCRIBE THE ENERGY SAVINGS CURVES THAT ADM PROVIDED FOR NV ENERGY FOR USE IN NV ENERGY'S COST EFFECTIVENESS MODELING.

A. For the ACE guru financial modeling – i.e., NV Energy's cost effectiveness modeling for DSM programs – ADM provided the appropriate energy savings curves for all 2023 DSM programs. The 2023 energy savings curves included program-level curves and subprogram-level curves. For example, the Energy Smart Schools Program has separate, subprogram-level curves for the behavioral subprogram versus the capital projects subprogram. Similarly, the DR programs have separate, subprogram-level curves for "Manage" device populations versus "Build" device populations.

ADM also provided the following normalized energy savings curves in support of NV Energy's "Distributed Energy Resources Analytics Toolset and Potential Study" project:

- Commercial DR Program curves – two curves each for Nevada Power and Sierra, sorted by DR event savings versus energy efficiency ("EE") savings from optimization algorithms.
- Residential DR Program curves – For each of the unique Nevada Power and Sierra device populations that control participants' air conditioning loads, there are two curves: one represents DR event savings while the other represents EE savings from smart thermostat optimization algorithms. There are additional non-air conditioning curves for DR events only: for Nevada Power, there are separate DR event curves for battery storage, pool pumps, and water heaters; for Sierra, there are separate DR event curves for battery storage and water heaters.
- Business Energy Services Program curves – separate (unique) curves for Nevada Power versus Sierra populations.
- Energy Smart Schools Program curves – unique curves for Nevada Power versus Sierra populations.
- Residential Direct Install Program curves – unique curves for Nevada Power and Sierra.
- Low Income Program curves – unique curves for Nevada Power and Sierra.
- Residential Codes and New Construction Program – unique curves for Nevada Power and Sierra.
- Residential Energy Assessments Program curves – unique curves for Nevada Power and Sierra.
- Home Energy Reports Program curves – unique curves for Nevada Power and Sierra.

- Energy Education Program – unique curves for Nevada Power and Sierra.
- Residential appliances measures – unique curves for Nevada Power and Sierra.
- Residential pool pump measures – one curve (Nevada Power only).
- Residential central air conditioning measures – unique curves for Nevada Power and Sierra.
- Room air conditioning measures – unique curves for Nevada Power and Sierra.
- DR battery storage curve – two curves representing different assumptions for battery efficiency.
- Commercial heating, ventilation, and air conditioning ("HVAC") measures – unique curves for Nevada Power and Sierra.
- Commercial lighting measures – unique curves for Nevada Power and Sierra.
- Commercial miscellaneous measures – unique curves for Nevada Power and Sierra.
- Commercial behind-the-meter ("BTM") battery storage measures – unique curves for Nevada Power and Sierra.
- Residential lighting measures – one (statewide) curve.
- Residential HVAC measures – unique curves for Nevada Power and Sierra.
- Residential domestic hot water measures – unique curves for Nevada Power and Sierra.
- Residential miscellaneous measures – unique curves for Nevada Power and Sierra.
- Residential BTM battery storage measures – unique curves for Nevada Power and Sierra.
- Residential electric vehicle managed charging measures – unique curves for each of the following populations: Nevada Power single-family, Nevada Power multifamily, Sierra single-family, and Sierra multifamily.

In ADM's judgement, all energy savings curves provided to NV Energy are appropriate for its cost effectiveness modeling for future, similar DSM programs and measures.

V. M&V USE OF AUTOMATED METERING INFRASTRUCTURE ("AMI") DATA

18. Q. WAS HOURLY AMI DATA USED FOR M&V ANALYSES FOR NV ENERGY'S 2023 DSM PROGRAMS? IF YES, PLEASE EXPLAIN HOW IT IS USED. IF NOT, PLEASE EXPLAIN WHY IT IS NOT USED.

A. Following is a description of AMI data used in M&V analyses for the 2023 DSM programs.

- Business Energy Services: AMI data was used for M&V analyses for five retro-commissioning projects. Energy simulations, engineering calculations, and field monitoring were the other most common analytical methods for evaluating this program (see Table 3-5 in the M&V report for this program).
- Commercial DR: AMI data was used to evaluate both the DR event demand reductions and kWh savings along with the annual energy savings attributed to smart thermostat technologies (see sections 3.2 and 3.3 in the M&V report for this program).
- Energy Smart Schools: AMI data was used for M&V analyses for Continuous Energy Improvement ("CEI") and Strategic Energy Management ("SEM") behavioral treatments. Energy simulations and engineering calculations were the other most common analytical methods for evaluating this program (see Table 3-3 in the M&V report for this program).
- Direct Install: AMI data was not used to evaluate this program. Engineering analyses were used to evaluate the measures in the program (see section 3.2 in the M&V report for this program).

- Energy Assessments: Monthly billing data[20] was used in mixed effects panel regression models to evaluate energy savings for the program components (see section 3.1 in the M&V report for this program).
- Energy Education: AMI data was not used to evaluate this program. Engineering analyses were used to evaluate the measures in the program (see section 3.2 in the M&V report for this program).
- Energy Reports: AMI data was not used to evaluate this program. Monthly billing data was sufficient to evaluate the energy savings for the program (see section 3.1 in the M&V report for this program).
- Home Energy Saver: AMI data was not used to evaluate this program. Engineering analyses were used to evaluate the measures in the program (see sections 3.1, 3.2, 3.3, and 3.4 in the M&V report for this program).
- Low Income: AMI data was not used to evaluate this program. Engineering analyses were used to evaluate the measures in the program (see section 3.2 in the M&V report for this program).
- Residential Codes and New Construction: AMI data was not used to evaluate this program. Engineering analyses were used to evaluate the measures in the program (see sections 3.5, 3.6, 3.7, and 3.8 in the M&V report for this program).
- Residential DR: AMI data was used in the DR event demand reductions and energy savings evaluation (see chapter 3 in the M&V report for this program).

VI. DR BATTERY STORAGE ANALYSIS

19. Q. PLEASE DESCRIBE ADM'S ANALYSIS OF THE BATTERY STORAGE COMPONENT OF THE 2023 RESIDENTIAL DR PROGRAM.

A. In 2023, NV Energy added non-thermostat devices to the Residential DR Program, including DR events for pool pumps, water heaters, and battery storage.

[20] Monthly billing data is NV Energy's aggregation of AMI data into monthly sums that are billed to customers.

With respect to the new DR battery storage measure, NV Energy's residential customers in both service territories can enroll existing batteries in the DR program. Customers subsequently earn incentives for participating in DR events, i.e., for allowing NV Energy to draw energy to the grid from customers' DR battery storage measures during DR events.

From August 28, 2023, to September 28, 2023, NV Energy conducted ten residential DR battery storage events, each of which lasted two hours. The first three events discharged the battery at a continuous three kW of demand, while the remaining seven events discharged a continuous five kW of demand during the event hours. Battery consumption was measured at the device level as the difference between the energy imported by the battery and the energy exported by the battery. Both data streams were measured in 15-minute intervals as Watt-hours, then converted to kWh by taking the average across each hour, quadrupling it, and dividing it by 1,000.

For weekday DR events, participating batteries' baseline load was calculated from batteries' average hourly discharge during the prior seven non-holiday weekdays. For weekend DR events, participating batteries' baseline load was calculated from batteries' average hourly discharge during the prior seven weekend days or holidays.

Nevada Power's 2023 DR battery storage events achieved maximum hourly verified demand reduction of 1.09 kW from one participating battery versus the baseline battery discharge. Detailed M&V findings regarding Nevada Power's DR battery storage events are provided in section 4.6.1 in the M&V report for 2023 the Residential DR Program.

Sierra's 2023 DR battery storage events achieved maximum hourly verified demand reduction of 9.06 kW from three participating batteries (i.e., an average of 3.02 kW per battery) versus the baseline battery discharge. Detailed M&V findings regarding Sierra's DR battery storage events are provided in section 4.10.1 in the same M&V report.

VII. LOW INCOME ANALYSES

20. Q. PLEASE DESCRIBE ADM'S ANALYSES RELATED TO NV ENERGY'S 2023 LOW INCOME PROGRAM AND LOW INCOME CUSTOMERS.

A. ADM provided an M&V analysis and report for NV Energy's 2023 standalone Low Income Program. ADM also assisted NV Energy with its analysis of the quantity of low-income customers that participated in the other 2023 DSM programs.

The standalone Low Income Program and the Home Energy Saver Program conducted outreach activities in 2023 to recruit low-income qualified customers for various energy efficiency products and services. The Low Income Program offered appliances and LEDs, while the Home Energy Saver Program offered an air conditioner tune-up measure for low-income customers. Both programs required proof of income qualification as described in the guidelines set out in the *NV Energy Low-Income Methodology Document*, which NV Energy had presented to the DSM Collaborative on August 20, 2020.

ADM analyzed the concatenated customer and site numbers (from DSMC tracking data) for all low-income qualified customers who participated in the 2023 standalone Low Income Program and the Home Energy Saver Program's air conditioner tune-up measure for low-income customers. ADM compared customer-site numbers for known low-income qualified customers to customer-site numbers for all customers who participated in the 2023 Residential Direct Install, DR, Energy Assessments, Home Energy Reports, Home Energy Saver, and Residential Codes and New Construction Programs.

For the Nevada Power residential programs listed below, ADM found the following percentages of low-income qualified customers:

- Home Energy Saver – 9.99 percent;
- In-Home Energy Assessments – 0.45 percent;
- Direct Install – 0.42 percent;
- Online Energy Assessments – 0.11 percent;
- DR – 0.09 percent;
- Home Energy Reports – 0.00 percent; and
- Residential Codes and New Construction – 0.00 percent.

For the Sierra residential programs listed below, ADM found the following percentages of low-income qualified customers:

- Home Energy Saver – 20.45 percent;
- In-Home Energy Assessments – 0.24 percent;
- Direct Install – 0.23 percent;
- Online Energy Assessments – 0.15 percent;
- DR – 0.04 percent; and
- Home Energy Reports – 0.00 percent.

In 2023, through its Energy Education Program, NV Energy provided an energy efficient lighting kit ("Kit")[21] to customers who may reside in low- or limited-income households. ADM administered surveys to a representative sample of 2023 Kit recipients. Survey instruments adhered to the low-income qualifications defined in the *NV Energy Low-Income Methodology Document*, which NV Energy had presented to the DSM Collaborative on August 20, 2020. From the 2023 surveys, Kit recipients self-reported the following:

- 99.87 percent of Nevada Power Kit recipients were low-income qualified; and
- 100.00 percent of Sierra Kit recipients were low-income qualified.

NV Energy is required by SB448 Section 39[22]to report the proportion of 2023 Energy Smart Schools ("ESS") participants that are public schools located in a historically underserved community"[23] as defined by eligibility for free or reduced price lunches.[24] ADM found the following percentages:

- Nevada Power – 94.04 percent of the 2023 ESS program population;
- Sierra – 71.43 percent of the 2023 ESS program population.

[21] NV Energy provided one Kit per household; each Kit included four 9W LED bulbs and two 0.5W LED night lights.
[22] NRS 704.7836.
[23] See https://www.leg.state.nv.us/NRS/NRS-704.html#NRS704Sec7836. This requirement was established through Senate Bill 448 (2021) (https://www.leg.state.nv.us/Session/81st2021/Bills/SB/SB448_EN.pdf).
[24] "Nevada lawmakers (on December 15, 2022) approved… more than $28 million to fund an additional year of universal free school meals for the 2023-24 school year…" See https://thenevadaindependent.com/article/lawmakers-ok-another-year-of-free-school-lunch-using-federal-arp-money, https://www.leg.state.nv.us/App/InterimCommittee/REL/Interim2021/Meeting/24291?committeeId=1773, and https://www.leg.state.nv.us/App/InterimCommittee/REL/Document/28633.

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VIII. AVOIDING DOUBLE-COUNTING OF SAVINGS FOR CROSS-PARTICIPANTS

21. Q. HOW DOES ADM ENSURE THAT ENERGY SAVINGS FOR CROSS-PARTICIPANTS ARE NOT DOUBLE COUNTED?

A. Cross-participants are customers who participated in more than one DSM program in a given program year. For example, a customer who concurrently participated in Residential Energy Assessments, Residential DR, and Direct Install Programs is a cross-participant in each program. ADM investigated cross-participation in our analyses for all programs to ensure that cross-participants' energy savings are not double-counted. The following example of a customer who is a cross-participant in the Residential Assessments Program, DR Program, and Direct Install Program demonstrates ADM's general methodology for ensuring that there is no double counting of savings:

- ADM separately calculates the direct install savings, which are subsequently reported for the Direct Install Program;
- If possible, ADM determines energy savings for DR Program measures using a regression model that excludes cross-participants. Alternatively, if excluding cross-participants results in an insufficient quantity of data for the regression analysis, then ADM includes cross-participants in the regression analysis but subtracts their Direct Install Program savings and reports the difference as the DR Program savings;
- If possible, ADM determines Residential Energy Assessments Program savings using a regression model without cross-participants. Alternatively, if excluding cross-participants results in an insufficient quantity of data for the regression analysis, then ADM includes cross-participants in the regression analysis but subtracts their DR Program savings and Direct Install Program savings and reports the difference as the Residential Energy Assessments Program savings.

IX. ONLINE ENERGY ASSESSMENTS PROGRAM

22. Q. DID ADM DETERMINE THAT THE ONLINE ENERGY ASSESSMENTS PROGRAM ACHIEVED SIGNIFICANT ENERGY SAVINGS IN 2023?

A. For the 2023 Online Energy Assessments Program, Nevada Power achieved ex-post verified annual energy savings of 4,117,409 kWh and Sierra achieved ex-post verified annual energy savings of 663,424 kWh.

23. Q. PLEASE DESCRIBE THE VARIABILITY THAT ADM HAS OBSERVED WHEN PERFORMING M&V ANALYSES FOR THE ONLINE ENERGY ASSESSMENTS PROGRAM.

A. Nevada Power's Online Energy Assessments Program has demonstrated variable ex-post annual energy savings during 2018 through 2023:

- Verified annual energy savings were 2,641,315 kWh in 2018 and 4,740,363 kWh in 2019.
- There were no statistically significant savings in 2020.
- Verified annual energy savings were 4,787,559 kWh in 2021.
- There were no statistically significant savings in 2022.
- Verified annual energy savings were 4,117,409 kWh in 2023.[25]

Sierra's Online Energy Assessments Program did not achieve statistically significant savings in 2018, 2019 or 2020, but subsequently achieved the following:

- Verified annual energy savings were 2,123,205 kWh in 2021, 5,556,164 kWh in 2022, and 663,424 kWh in 2023.[26]

[25] Notably, 2023 participants only included the subset of customers who completed the Home Profile Survey, whereas prior year participants included all customers who opened the Online Energy Assessments tool.
[26] Id.

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24. Q. IN ADM'S OPINION, DO THE M&V FINDINGS FOR THE 2023 ONLINE ENERGY ASSESSMENTS PROGRAM REPRESENT OUTLIERS?

A. Given that there have been multiple years of verified savings for the Online Energy Assessments Program commingled with multiple years of no savings, it is difficult to determine if the M&V result for 2023 or any other single year is an outlier.

The Online Energy Assessments Program is a behavioral treatment that shows savings if numerous participants take actions that save energy in the same calendar year in which the participants used the Online Energy Assessments tool.

The annual timing of required M&V activities may contribute to this program's inconsistent year-to-year energy savings. M&V activities align with calendar years. Customer actions in response to behavioral treatments do not necessarily align with calendar years; a customer may delay energy saving actions for several months even if the Online Energy Assessments tool provided the impetus for those actions.

Further, people's actions and timing are influenced by their individual perceptions of costs, benefits, and economic uncertainties. Economic uncertainties in the post-pandemic period, potentially including 2023, have included supply chain issues, labor shortages, and persistent (albeit currently abating) inflation. During any program year, a given user of the Online Energy Assessments tool may be experiencing financial stresses or uncertainties while concurrently having favorable views and good intentions regarding energy conservation. One user may act rationally by promptly addressing energy conservation opportunities while another user may act rationally by delaying energy saving actions.

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It is possible that a subset of users of the Online Energy Assessments tool need more time than a single calendar year to achieve energy saving actions that were impelled by the Online Energy Assessments tool. In 2023, ADM tested this hypothesis by conducting an exploratory regression analysis across multiple previous program years of participants. The purpose of the analysis was to determine if statistically significant savings are found if participants are allowed more time – e.g., possibly up to a year, on average – to achieve energy saving actions after having used the Online Energy Assessments tool. Appendix D in the M&V report for the 2023 Energy Assessments Program provides a discussion of ADM's exploratory regression analysis of longer-term savings for users of the Online Energy Assessments in previous program years.

X. HOME ENERGY REPORTS PROGRAM

25. Q. WHY ARE SAVINGS FOR THE HOME ENERGY REPORTS ("HERS") PROGRAM HIGHER IN 2023 THAN IN 2022?

A. The 2022 program year was the first year of the behavioral treatment for the current HERs cohort; whereas the 2023 program year was the second consecutive year of treatment of the same cohort. In ADM's experience evaluating similar HERs programs in Nevada and nationally, lower energy savings during the first year of treatment is expected and is typically followed by increased savings during the second year of treatment of the same cohort.

The characteristic of relatively low first-year energy savings can be observed by looking back at NV Energy's 2019 and 2020 behavioral programs. In the first year of treatment of the 2019 HERs cohort, which was a new cohort at the time, annual per household energy savings were 47.5 kWh for the Nevada Power treatment group and 43.8 kWh for the Sierra treatment group. During 2020, the second year

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of treatment of the same cohort, annual per household energy savings increased to 94.9 kWh for the Nevada Power treatment group and 73.0 kWh for the Sierra treatment group.

26. Q. WAS THE TREATMENT DURATION FOR THE 2023 HERS PROGRAM GREATER THAN THE TREATMENT DURATION IN 2022?

A. Yes. The treatment duration for the HERs cohort was significantly longer during 2023 compared to 2022.

For Nevada Power, nearly all of the HERs cohort began receiving treatment in May 2022. For the Sierra HERs cohort, 2022 treatments commenced as follows: ten percent began in March 2022, ten percent began in April 2022, and the remainder began in May 2022. Thus, for both Nevada Power and Sierra, the 2022 treatment periods resulted in an average of approximately eight months of treatment data that were available for M&V analyses for the 2022 HERs program.

The same Nevada Power and Sierra HERs cohorts received treatment throughout all of 2023, resulting in an average of approximately 20 consecutive months of treatment data that were available for M&V analyses for the 2023 HERs program. Higher annual energy savings during 2023, the second year of treatment, correlates to the consecutive months of ongoing behavioral treatment.

27. Q. IN ADM'S OPINION, DO THE M&V FINDINGS FOR THE 2023 HERS PROGRAM REPRESENT OUTLIERS?

A. No. In ADM's judgement, it is logical that the average annual energy savings per household increased significantly in 2023, which was a full year of treatment that followed the prior program year's briefer (eight month) first-year treatment.

In 2023, the Nevada Power HERs treatment group achieved average annual energy savings of 369.3 kWh per home.[27] The 2023 average annual savings per home represents 2.27 percent of pre-treatment annual energy consumption (see section 5.1 in the M&V report for this program). For hot-climate residences that have substantial summer cooling loads that result in relatively high summer energy bills, 2.27 percent savings is not an outlier for HERs behavioral treatments.

In 2023, the Sierra HERs treatment group achieved an average of 116.1 kWh annual energy savings per home.[28] The 2023 average annual savings per home represents 1.14 percent of pre-treatment annual energy consumption (see section 5.1 in the same M&V report), which is not an outlier for HERs behavioral treatments.

XI. M&V DATA COLLECTION TOPICS

28. Q. DID THE COVID-19 PANDEMIC CEASE TO IMPACT M&V DATA COLLECTION ACTIVITIES IN 2023?

A. Yes. The COVID-19 pandemic did not impact M&V activities in 2023.

29. Q. IN 2023, HOW WAS M&V DATA COLLECTION ACCOMPLISHED?

A. ADM achieved the majority of 2023 M&V data collection through remote activities that included phone interviews and email conversations with customers. M&V analyses also utilized AMI data (remotely collected data) whenever possible.

[27] For the Nevada Power HERs cohort, prior-year (2022) savings per home averaged 5.1 kWh. However, the 2022 "Paper HERs" subset of the treatment group saved an average of 248.2 kWh per home. The reason overall average savings was only 5.1 kWh was due to ADM's finding of zero statistically significant savings for treatment group subsets other than the "Paper HERs" subset.

[28] For the Sierra HERs cohort, prior-year savings per home averaged 54.8 kWh.

ADM did not conduct any 2023 M&V onsite inspections or data collection at customers' residences, as all data needed for M&V analyses was collected without entering customers' homes. However, for Low Income and Direct Install Programs, ADM conducted onsite verification of the counts of replaced bulbs at the Las Vegas and Reno warehouses where the old bulbs were stored prior to their disposal.

For the Business Energy Services Program, ADM conducted M&V onsite inspections for two projects, which were the largest projects in each service area. For each M&V onsite inspection, ADM collaborated with NV Energy management and customers to ensure that ADM personnel used appropriate personal protective equipment in compliance with all site-specific requirements and all NV Energy and state of Nevada requirements.

M&V data collection for the Business Energy Services Program also included 41 phone interviews and nine email conversations with participants who completed energy conservation projects in 2023.

For the Energy Smart Schools Program, M&V data collection included email conversations with officials in two school districts that had implemented energy conservation projects for which ADM identified some uncertainties regarding the M&V data-of-interest.

30. Q. WHY WAS THE MAJORITY OF 2023 M&V DATA COLLECTED THROUGH REMOTE ACTIVITIES?

A. ADM strives to continually improve M&V processes and accuracy of reporting while respecting finite M&V budgets. During and after the COVID-19 pandemic, ADM increased the use of AMI data whenever it is equivalent to, or better than, data that could be collected in the field. ADM also works closely with NV Energy and program implementers. For example, whenever implementers can collect data in the field that can be used in M&V analyses, ADM uses the implementer-collected field data to supplement or corroborate M&V analyses.

Remote M&V data collection is the financially prudent option if there is low uncertainty regarding the data-of-interest. For example, prior to the COVID-19 pandemic, ADM had planned to execute a multi-year monitoring study of effective full load hours ("EFLH") for residential air conditioning equipment in southern Nevada. After postponing the study for two years during the pandemic, the ADM team objectively critiqued our premises and considered the relative uncertainty of EFLH. ADM determined that there was low uncertainty regarding EFLH for residential air conditioning equipment. Independent, third-party M&V analysts had studied EFLH in southern Nevada for 15 years, and ADM had used AMI data to determine EFLH for multiple years. Across all the EFLH analyses, there were relatively small variances from year to year. Therefore, rather than spending several thousands of dollars to collect additional data, ADM reviewed 15 years of EFLH analyses to develop a deemed value for southern Nevada residential air conditioning equipment.

Onsite M&V data collection is the prudent option when there is high uncertainty regarding the data-of-interest. For example, onsite M&V data collection is required for large commercial projects for which there are numerous attributes, inputs, and usage areas that require detailed engineering calculations and/or energy modeling that are subject to potentially unique operations and energy loads.

As mentioned in the preceding Q&A, ADM's onsite verification of the bulbs replaced by the Low Income and Direct Install Programs is another example of M&V data collection that is considered prudent because (absent onsite verification) there is significant uncertainty regarding the efficiency of the replaced bulbs.

31. Q. WHEN ONSITE M&V DATA COLLECTION IS NEEDED, DO NV ENERGY'S CUSTOMERS COOPERATE WITH M&V EFFORTS?

A. Yes. Please note that this Q&A is included because the Regulatory Operations Staff ("Staff") of the Commission asked ADM this important question during a 2023 conversation that included NV Energy and statutory intervenors. Staff emphasized that, given that participating customers receive ratepayer-funded rebates, they are required to let ADM perform onsite M&V data collection.

ADM agrees that customers receiving ratepayer-funded rebates must cooperate with onsite M&V requirements as determined by the independent, third-party M&V contractor. ADM is confident that onsite M&V is performed prudently and effectively – and customers are almost universally cooperative and helpful. I cannot recall any examples of customer pushback during the past several years.

ADM strives to collaborate effectively with all parties, communicate in helpful ways, and optimize onsite data collection when it is required. ADM's basic approach is to respect customers. When phone interviews and email conversations are the best use of M&V resources and finite budgets (for M&V sample sites for which ADM has determined that there is relatively low uncertainty regarding the data-of-interest), ADM staff explains to customers that their collaboration and helpfulness may enable the ADM team to achieve accurate results without needing to go into their business for an onsite inspection. Thus, for relatively low uncertainty M&V sample sites, ADM typically offers to remotely collect M&V data via phone interviews and email conversations. Most customers recognize that ADM is striving for efficiency and minimal intrusion if the customers, in turn, are diligent and helpful providing the required data. Customers also know that, if M&V data collection is not successful in the remote mode, ADM will go to customers' businesses to perform the more time-consuming and intrusive onsite inspection and data collection.

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

A. Yes.

EXHIBIT OLIVER-DIRECT-1

STATEMENT OF QUALIFICATIONS

ROBERT R. OLIVER
ADM ASSOCIATES, INC. (ADM)
417 W. Plumb Lane
Reno, NV 89509

Education

Bachelor of Science in Agricultural Economics and Business Management, Cornell University

Professional Experience

2010 to Present | **Director/Principal**
ADM Associates, Inc.

Responsible for evaluation, measurement and verification (EM&V) of Demand Side Management (DSM) portfolios including the full range of demand response (DR), energy efficiency (EE), and educational program offerings. In recent years, have provided analyses, oversight, direction, and consultation for EM&V scopes of work in various regions of the country, including the following.

- EM&V consulting services for commercial, industrial, agricultural, low-to-moderate income, and residential EE programs in Arkansas, California, Idaho, Kansas, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Utah, Washington, and Wyoming.
- DR programs in Kansas, Missouri, and Nevada.
- Various EM&V analyses and support for ADM's EM&V teams in numerous states.

Provide electric and gas utility clients technical services including DSM portfolio design and related analyses; also provide technical reference manual (TRM) review and participate in TRM and similar collaborative processes. Provide clients innovative analyses and methods for utilizing measure-level load shapes and program-level energy savings profiles to maximize accuracy of reporting for peak demand savings. Provide guidance and quality assurance for EM&V sampling to ensure rigorous sampling while prudently managing EM&V budgets and resources. Serve as lead writer, editor or peer reviewer for numerous EM&V reports and related technical documents.

2007 to 2009 | **Senior Program Manager**
Paragon Consulting Services

Responsibilities included EM&V tasks such as managing field engineering, data collection and data analysis activities, while also preparing EM&V work papers and reports for DSM programs.

2005 to 2007 | **Southwest Regional Manager**
Ecos Consulting, Inc.

Consulted for various southwestern utilities while responsible for providing clients DSM program design and execution. Successfully implemented innovative residential initiatives such as pool pump programs and ENERGY STAR® lighting and appliances programs.

2001 to 2005 | **Independent Consultant**

Provided consulting services to support the Nevada Task Force for Renewable Energy and Energy Conservation (2004-2005). Also advised various clients on strategies for increasing market penetration of renewable energy systems and managing internal and external communications.

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, ROBERT R. OLIVER, 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: May 31, 2024

ROBERT R. OLIVER