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In accordance with NRS Chapter 719,
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by: /s Lynn DInnocenti

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DEEMED FILED ON 9/5/25 DUE TO NETWORK OUTAGE

August 29, 2025

Ms. Trisha Osborne, Assistant Commission Secretary
Public Utilities Commission of Nevada
Capitol Plaza
1150 East William Street
Carson City, Nevada 89701-3109

RE: 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 Energy Supply Plan Update for 2026 and 2027.

Dear Ms. Osborne:

Due to unforeseen circumstances with the Public Utilities Commission of Nevada's ("Commission") website making the Commission's electronic filing system unavailable, Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy (the "Companies") are serving the attached Joint Energy Supply Plan Update on the parties of record in the above-referenced docket via e-mail. Pursuant to the Commission's Request, the Companies are also hand-delivering a courtesy copy of the documents on CD/USB to the Commission. Once the Commission's electronic filing system is available, the Companies will file the attached document and serve the proof of filing, along with this correspondence, on the parties of record.

Should you have any questions regarding this filing, please contact me at (775) 834-5793 or michael.knox@nvenergy.com.

Respectfully submitted,

/s/ Michael D. Knox
Michael D. Knox
Senior Attorney

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 for Approval of their Joint Energy Supply Plan Update for period 2026.	Docket No. 25-08___

VOLUME 1 OF 2

NEVADA POWER COMPANY D/B/A NV ENERGY
AND SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY

TRANSMITTAL LETTER

August 29, 2025

Ms. Trisha Osborne, Assistant Commission Secretary
Public Utilities Commission of Nevada
Capitol Plaza
1150 East William Street
Carson City, Nevada 89701-3109

RE: 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 Energy Supply Plan Update for 2026 and 2027.

Dear Ms. Osborne:

Enclosed for filing please find Nevada Power Company d/b/a NV Energy's ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy's ("Sierra" and, together with Nevada Power, the "Companies" or "NV Energy") Joint Application for Approval of their Energy Supply Plan Update for 2026 and 2027 (the "ESP Update").

A Courtesy copy of the electronic copies of the filing, along with the executable electronic copies of load forecasting and work papers will be delivered to the Regulatory Operations Staff ("Staff"), and the Attorney General's Bureau of Consumer Protection ("BCP") in both their Carson City and Las Vegas offices.

Consistent with the Commission's electronic filing regulations as adopted in Docket No. 07-03015, following this cover letter please find a table of contents for the complete filing. A breakdown appears on the cover page which provides the page reference for each item in the volume.

Accompanying this transmittal letter are portions of the filing that are to be kept under seal pursuant to NRS § 703.190(2) and NAC § 703.527 *et seq*. This information is contained in a sealed envelope appropriately marked, and contains the unredacted versions of the following:

Customer Specific Information. Portions of Section 2(b)(1) of the ESP Update Narrative, the workpapers for the Load Forecast Technical Appendix ESP LF-1, and the Exhibit Pollard-Direct-2 include customer specific information. These forecasts include reports of future load provided directly by customers. This information is highly confidential to the providing customers and is provided to the Companies on condition that they maintain confidentiality.

PLEXOS Reports. The PLEXOS results set forth in ECON-1 (Confidential) are confidential. If made public, savvy market participants could use this information to determine Nevada Power and Sierra's marginal cost to produce energy. This information discloses key operating characteristics of the Companies' generation fleet and the Companies' views and expectations of relevant markets and their future procurement plans.

Natural Gas Price Forecasts. Sierra's natural gas price forecasts constitute commercially sensitive and/or trade secret information that derive independent economic value from not being generally known. This information discloses Sierra's 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 Sierra by limiting its ability to foster competition among prospective suppliers, compromising Sierra's negotiating position and reducing its bargaining leverage. Publication of this information impair Sierra's ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of its customers. This information is contained in Section 3.B of the ESP Update and FPP-1.

Power Price Forecast. Sierra's power price forecasts constitute commercially sensitive and/or trade secret information that derive independent economic value from not being generally known. This information discloses Sierra's 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 Sierra by limiting its ability to foster competition among prospective suppliers, compromising Sierra's negotiating position and reducing its bargaining leverage. Publication of this information impair Sierra's ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of its customers. This information is contained in Section 3.B of the ESP Update and FPP-1.

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, after which time the Commission may destroy or return the confidential information, at its convenience. Confidential workpapers will be provided as a courtesy via the attached storage device to the Commission.

The Companies have transmitted protective agreements to the Staff and BCP so that they may be expeditiously served with the confidential information described above. Confidential workpapers will be provided as a courtesy via storage device to the Staff and the BCP upon fully executed protective agreement.

Should you have any questions regarding this filing, please contact me at (775) 834-5793 or michael.knox@nvenergy.com.

Respectfully submitted,

/s/ Michael D. Knox
Michael D. Knox
Senior Attorney

TABLE OF CONTENTS

NEVADA POWER COMPANY D/B/A NV ENERGY
AND SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY

TABLE OF CONTENTS

VOLUME 1 OF 2

VOLUME 2 OF 2
TECHNICAL APPENDIX

CERTIFICATE OF SERVICE

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing filing of **NEVADA POWER COMPANY D/B/A NV ENERGY AND SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY** in Docket No. 25-080__ upon all parties of record in this proceeding by electronic service to the following:

Don Lomoljo
Public Utilities Comm. of Nevada
1150 E. William Street
Carson City, NV 89701-3109
dlomoljo@puc.nv.gov

Staff Counsel Division
Public Utilities Comm. of Nevada
9075 West Diablo, Suite 250
Las Vegas, NV 89148
pucn.sc@puc.nv.gov

Attorney General's Office
Bureau of Consumer Protection
100 N. Carson St.
Carson City, NV 89701
bcpserv@ag.nv.gov

Michael Saunders
Attorney General's Office
Bureau of Consumer Protection
8945 W. Russell Road, Suite 204
Las Vegas, NV 89148
msaunders@ag.nv.gov
bcpserv@ag.nv.gov

DATED this 29th day of August, 2025.

/s/ Lynn D'Innocenti
Lynn D'Innocenti
Paralegal
Nevada Power Company d/b/a NV Energy
Sierra Pacific Power Company d/b/a NV Energy

APPLICATION

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 for Approval of their Joint Energy Supply Plan Update for period 2026-2027.	))))	Docket No. 25-08___

APPLICATION

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"), make this Application for Approval of their Joint 2025 Energy Supply Plan Update (the "ESP Update") pursuant to Section 704.9506 of the Nevada Administrative Code ("NAC"). The Application is made under NAC § 704.535.

I. SUMMARY OF APPLICATION

NAC § 704.9506 requires that 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 energy supply plan ("ESP") that will be applicable to the remaining period of its Action Plan. The Companies' last Triennial Integrated Resource Plan ("IRP") and ESP were filed in May 2024 and addressed the Action Plan period of 2025 to 2027 (*see* Docket No. 24-05041). Through this Application, the Companies seek the Public Utilities Commission of Nevada's ("Commission") approval and acceptance of their ESP Update for the second and third year of the Action Plan period addressed in the Companies' Triennial IRP and ESP. NAC § 704.9506(2) requires that an ESP Update be based on the most recent load forecast available at the time it is prepared. The Companies prepared an updated load forecast for this filing. The forecast for this ESP Update is suitable for making planning decisions during the ESP Update Period (calendar years 2026-2027).

The Companies have a combined open power position of 1,020 MW in 2026 and 1,926 in 2027. Additionally, the Companies propose to continue their four-season laddering strategy to fill open power positions through 2027. Any proposed purchases of greater than three years in duration will be submitted to the Commission for approval in accordance with

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

NAC §§ 704.9113 and 704.9512. The ESP Update calls for the Companies to monitor the power portfolio on a continuous basis and to procure products only as needed.

The Companies will continue to implement the currently-approved four-season laddering strategy to procure physical gas, and seek approval for no new additional gas transportation contracts at this time. Sierra requests acceptance and approval to maintain its current natural gas transportation portfolio by renewing all existing gas transportation contracts with TransCanada Pipeline Ltd., Northwest Pipeline, Tuscarora Gas Transmission Company, and Great Basin Gas Transmission Company. The Companies propose continuing their current hedging strategy and will acquire no natural gas hedges during the ESP Update period.

The Coal Supply Plan notes that Sierra has coal purchase and transportation agreements in place to provide enough supply to meet Valmy Station's coal requirements through the end of 2025. The units at Valmy Station will be transitioned to natural gas supplied via transportation contracts with Ruby Pipeline and Pinyon Pipeline. Under this plan, Sierra will not solicit or enter into any long-term coal supply agreements.

Finally, the Companies seek approval of their risk management strategy and a finding that they have satisfied their single outstanding compliance item.

II. The Applicant

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 fourteen northern Nevada counties, including the communities of Carson City, Minden, Gardnerville, Reno, Sparks, and Elko. 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:

Michael Knox	Trevor Dillard
Senior Attorney	Director, Regulatory Services
6100 Neil Road	6100 Neil Road
Reno, NV 89511	Reno, NV 89511
775-834-3551	775-834-5823
michael.knox@nvenergy.com	regulatory@nvenergy.com

III. THE FILING

A. Introduction

The Commission's regulations obligate the Companies to provide an annual update to their triennial ESP.[1] This ESP Update satisfies this requirement and addresses the second and third year of the period covered by the Action Plan from the Companies' last triennial ESP (calendar years 2026-2027). The ESP Update sets forth the Companies' purchased power procurement plan (NAC § 704.9482(3)), fuel procurement plan (NAC § 704.9482(4)), and risk management strategies (NAC § 704.9482(5)). These plans and strategies govern the Companies' day-to-day operations and facilitate the provisioning of reliable electric service to customers and just and reasonable rates.

B. Elements of the Filing

The ESP Update consists of two volumes and is organized as follows:

Volume 1 - Transmittal Letter, Table of Contents, Certificate of Service, Application, Draft Notice, Testimony and Narrative

Volume 2 - Technical Appendices LF-1, GAS-1 through GAS-2, FPP-1, RM-1 through RM-3 and ECON-1

[1] NAC § 704.9506(1).

C. Witnesses Providing Prepared Testimony in Direct Case

The Companies have prepared and filed written testimony of several witnesses to support the ESP Update. The Companies are prepared to present their witnesses in their direct case at any hearing scheduled in this matter. Specifically, the Companies intend to call the following witnesses to sponsor prepared written testimony in their direct case:

Janet Wells, Vice President, Integrated Resource Planning. Ms. Wells serves as the 2025 Energy Supply Plan Update ("ESP Update") policy witness, introduces the Companies' witnesses, describes the preparations of the ESP Update, and describes and provides an overview of the ESP. Ms. Wells also sponsors or co-sponsors sections in the Companies' ESP: Section 1 ("Executive Summary"); Section 8 ("Determination of Prudence under Nevada Administrative Code ("NAC") §§ 704.9508(2) and 704.9494"); and Section 9 ("Commission Directives").

Catalin Adrian Cacuci, Treasurer. Mr. Cacuci sponsors Section 7 ("Risk Management Strategy") and portions of Section 8 ("Determination of Prudence") of the Companies' 2025 Joint Energy Supply Plan Update ("ESP"), which covers the three year period from 2026 through 2027. Mr. Cacuci describes the role of the Risk Control organization in managing energy supply risk. In addition, Mr. Cacuci sponsors Technical Appendix RM-1 through RM-3.

Michael Holland, Vice President, Resource Optimization. Mr. Holland serves as the overall policy witness, introduces the Companies' witnesses, describes the preparations of the ESP Update, and provides an overview of the ESP Update. Mr. Holland sponsors Section 2.C ("Energy Requirements"); Section 2.G ("Financial Gas Requirements"); Section 4 ("Power Procurement Plan"); Section 5.A ("Physical Gas Procurement Plan"); Section 5.C ("Recommended Gas Hedging Plan"); Section 6.

("Coal and Valmy Closure"). In addition, Mr. Holland also sponsors Technical Appendix GAS-1 - Gas Hedging Workshop Presentation.

Charles McCutchen, Production Cost Modeling Lead. Mr. McCutchen sponsors Section 2.B ("Capacity Requirements"), Section 2.E ("Gas Transportation Requirements"), Section 2.F ("Physical Gas Requirements"), and co-sponsors Section 2.C ("Energy Requirements"). He also sponsors 2026-2027 Estimated Cost to Serve for the Companies in Section 8 and Technical Appendix ECON-1.

Tim Pollard, Director, Load Forecasting and Customer Analytics. Mr. Pollard sponsors the load forecast, which is described in Section 2.A of the ESP narrative. In addition, Mr. Pollard Sponsors Technical Appendix LF-1.

Lindsey Schlekeway, Director of Market Policy. Ms. Schlekeway sponsors portions of Section 3.A. ("Market Fundamentals") of the ESP update which relate to regional market development and the Western Resource Adequacy Program ("WRAP").

Sean Spitzer, Director, Renewable Energy & Origination. Mr. Spitzer, sponsors the Renewable Energy Planning section, Section 2.D.

Matthew Valentic, Revenue Requirement and FERC Manager. Mr. Valentic sponsors Technical Appendix Item GAS-2, which provides actual and forecasted Base Tariff Energy Rates ("BTER") and Deferred Energy Accounting Adjustment ("DEAA") components.

Vincent Vitiello, Gas Supply Planning Lead. Mr. Vitiello sponsors Section 5.B ("Gas Transportation Plan").

Zeljko Vukanovic, Market Fundamentals Lead. Mr. Vukanovic sponsors Section 3.A ("Market Fundamentals") – except Regional Market Development – and Section 3.B ("Fuel and Purchased Power Price Forecasts") and also Technical Appendix FPP-1, the fuel and purchased power price forecasts.

D. Determination that the Elements of the ESP Update are Prudent

Pursuant to NAC § 704.9508(2), the Commission reviews an ESP Update under the same standards that apply to the Commission's review of an ESP.[2] The Commission may determine that the elements of an energy supply plan update are prudent if the following criteria are met:

> (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.
>
> (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.
>
> (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.[3]

The ESP Update satisfies these criteria. The Companies acknowledge that the prudence of their implementation of an approved ESP Update will be determined in a future deferred energy proceeding. In addition, pursuant to NAC § 704.9504, the Companies may

[2] NAC § 704.9508(2).

[3] NAC § 704.9494.

deviate from an approved ESP Update "to the extent necessary to respond adequately to any significant change in circumstances not contemplated by the energy supply plan."

IV. Confidential Information

The Companies request confidential treatment of a portion of the load forecast, the proposed cap on premiums to be paid for physical gas supplies, and other portions of this filing as outlined below. These requests are made pursuant to NAC § 703.7274.

Customer-Specific Information. Portions of Section 2(b)(1) of the ESP Update Narrative, the workpapers for the Load Forecast Technical Appendix ESP LF-1, and the Exhibit Pollard-Direct-2 include customer specific information. This information is highly confidential to these customers and is provided to the Companies on the ocndition that they maintain confidentiality. This information should not be made public witout the consent of the customers identified.

PLEXOS Reports. The PLEXOS results set forth in ECON-1 (Confidential) are confidential. If made public, savvy market participants could use this information to determine the Companies' marginal cost to produce energy. This information discloses key operating characteristics of the Companies' generation fleet and the Companies' views and expectations of relevant markets and their future procurement plans. 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 their bargaining leverage. Publication of this information would unfairly advantage competing buyers and impair the Companies' ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of their customers.

Natural Gas Price Forecasts. Sierra's natural gas price forecasts constitute commercially sensitive and/or trade secret information that derive independent economic value from not being generally known. This information discloses Sierra's 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 Sierra by limiting its ability to foster competition among prospective suppliers, compromising Sierra's negotiating position and reducing its bargaining leverage. Publication of this information would impair Sierra's ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of its customers. This information is contained in Section 3.B of the ESP Update and FPP-1.

Power Price Forecasts. Sierra's power price forecasts constitute commercially sensitive and/or trade secret information that derive independent economic value from not being generally known. This information discloses Sierra's 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 Sierra by limiting its ability to foster competition among prospective suppliers, compromising Sierra's negotiating position and reducing its bargaining leverage. Publication of this information would impair Sierra's ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of its customers. This information is contained in Section 3.B of the ESP Update and FPP-1.

The "Confidential Material" envelope accompanying this Application contains a confidential and unredacted copy of each page of the ESP Update (in a sealed envelope with a copy of the first page of this Application securely fastened thereon) and with each confidential page stamped "CONFIDENTIAL AND UNREDACTED." The Companies request that the Commission maintain the confidentiality of this information for a period of no less than five years, after which the Commission may return or destroy this information, as is most convenient to the Commission.

V. Requests for Relief

Nevada Power and Sierra respectfully request that pursuant to NAC § 704.9508(1), the Commission convene a hearing on this ESP Update within 60 days of the filing date, and issue an order accepting this ESP Update within 120 days and containing the following findings:

1. **Load Forecast:** A finding that the updated load forecast used for this ESP Update is suitable for making planning decisions during the ESP Update period (2026-2027).

2. **Power Procurement/Sales Plans:** Acceptance and approval of their power procurement/sales plan, including acceptance and approval of their plan to implement a four-season laddering strategy for physical energy and/or capacity procurement to manage the open capacity position, and an affirmative finding consistent with NAC § 704.9494(3) that their power procurement strategy is prudent.

3. **Physical Gas Procurement Plan:** Acceptance and approval of their plan to continue to implement their four-season laddering strategy for physical gas supply, and an affirmative finding consistent with NAC § 704.9494(3) that their physical gas procurement strategy is prudent.

4. **Gas Transportation Plan:** Acceptance and approval of their gas transportation plan, and an affirmative finding consistent with NAC § 704.9494(3) that their gas transportation strategy is prudent.

5. **Gas Hedging Plan:** Acceptance and approval of their gas hedging plan, which continues the current hedging strategy pursuant to which the Companies will not acquire natural gas hedges during the ESP Update period, and an affirmative finding consistent with NAC § 704.9494(3) that their gas hedging strategy is prudent.

6. **Coal Procurement Plan**: Acceptance and approval of Sierra's Coal Procurement Plan, and an affirmative finding consistent with NAC § 704.9494(3) that its coal procurement strategy is prudent.

7. **Risk Management Strategy:** Acceptance and approval of their risk management strategy and a finding that the strategy identifies risks inherent in procuring and obtaining a supply portfolio and establishes the means by which the utilities plan to address and balance or hedge the identified risks related to cost, price volatility and reliability. The

Companies are requesting an affirmative finding consistent with NAC § 704.9494(3) that their risk management strategy is prudent.

8. **Directives:** A finding that the Companies have satisfied their obligation to continue to hold quarterly workshops with Regulatory Operations Staff and the Attorney General's Bureau of Consumer Protection to review the implementation of the constituent elements of the ESP Update and the approved hedging strategy as contained in Commission Order dated December 2, 2020, in Docket No. 20-09002.

9. **Confidential Treatment:** Grant the Companies' request for confidential treatment of certain information filed under seal as described above.

10. **Other Relief:** Grant any other relief that the Commission deems appropriate based on the Application and the record adduced at any hearing held in this matter.

Dated and respectfully submitted this 29th day of August, 2025.

NEVADA POWER COMPANY
D/B/A NV ENERGY

SIERRA PACIFIC POWER COMPANY
D/B/A/ NV ENERGY

/s/ Michael Knox

Michael Knox
Senior Attorney
6100 Neil Road
P.O. Box 10100
Reno, Nevada 89511
Tel: 775-834-5793
Fax: 775-834-4811
Email: michael.knox@nvenergy.com

DRAFT NOTICE

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 **ONE COPY** of this form with your filing. (Completion of this form may require the use of more than one page.)

A title that generally describes the relief requested (see NAC 703.160(4)(a)):

> **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 Energy Supply Plan Update for 2026-2027.**

The name of the applicant, complainant, petitioner or the name of the agent for the applicant, complainant or petitioner (see NAC 703.160(4)(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 **AND** the effect of the relief or proceeding upon consumers (see NAC 703.160(4)(c)):

> **Nevada Power and Sierra Pacific are seeking approval of their Joint Energy Supply Plan Update ("ESP Update") for calendar years 2026 and 2027, which is filed pursuant to NAC § 704.9506, and sets forth the Companies' power procurement plan, fuel procurement plan, and risk management strategy. NAC § 704.9506(1) requires that Nevada Power and Sierra file an update of the energy supply plan on or before September 1, 2025. The ESP Update includes a power procurement plan, a fuel procurement plan and risk management strategies. The Companies request that the Public Utilities Commission of Nevada approve this ESP Update and make the determinations of prudence provided for in NAC § 704.9494 regarding each element of the plan.**

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**

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[1] NRS 704.069 states in pertinent part:

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

JANET WELLS

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

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2025 Energy Supply Plan Update
Docket No. 25-08___

Prepared Direct Testimony of

Janet Wells

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

A. My name is Janet Wells. My current position is Vice President, Integrated Resource Planning, 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, Reno, Nevada 89511. I am filing testimony on behalf of the Companies.

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

A. I hold a Bachelor of Arts Degree in Geography and a Master of Science Degree in Applied Economics and Statistics. I have 18 years of utility experience within the Rates and Regulatory Affairs department. Prior to joining the Companies, and during an absence from the Companies, I worked in economic consulting and research. More details regarding my background and experience are provided in **Exhibit Wells-Direct-1.**

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

A. My current responsibilities involve leading the distribution, transmission, and resource planning functions as well as load forecasting and research.

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

A. Yes, most recently in Docket No. 25-02033, the Annual Deferred Energy Accounting Adjustment Application. **Exhibit Wells-Direct-1** provides a full list of proceedings in which I have testified before the Commission.

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

A. As the 2025 Energy Supply Plan Update ("ESP Update") policy witness, I introduce the Companies' witnesses, describe the preparation of the ESP and describe and give an overview of the ESP. I also sponsor or co-sponsor the following sections in the Companies' ESP:

- Section 1 ("Executive Summary");
- Section 8 ("Determination of Prudence under Nevada Administrative Code ("NAC") §§ 704.9508(2) and 704.9494"); and
- Section 9 ("Commission Directives").

6. Q. **ARE YOU SPONSORING ANY TECHNICAL APPENDIX ITEMS?**

A. No.

7. Q. **PLEASE IDENTIFY THE WITNESSES WHO WILL TESTIFY IN THE COMPANIES' DIRECT CASE.**

A. In addition to myself, the following witnesses testify in the Companies' direct case:

Adrian Cacuci, Treasurer. Mr. Cacuci sponsors Section 7 of the ESP, which relates to the Risk Control organization and strategy. Mr. Cacuci describes the role of the Risk Control organization in managing energy supply risk. In addition, Mr. Cacuci co-sponsors portions of Section 8 of the ESP and also sponsors Technical Appendix RM-1 through RM-3.

Michael Holland, Vice President of Resource Optimization. Mr. Holland sponsors Section 2.C ("Energy Requirements"); Section 2.G ("Financial Gas Requirements"); Section 4 ("Power Procurement Plan"); Section 5.A ("Physical Gas Procurement Plan"); Section 5.C ("Recommended Gas Hedging Plan"); and Section 6. ("Coal and Valmy Closure"). In addition, Mr. Holland also sponsors Technical Appendix GAS-1.

Charles McCutchen, Production Cost Modeling Lead. Mr. McCutchen sponsors Section 2.B ("Capacity Requirements"), Section 2.E ("Gas Transportation Requirements"), Section 2.F ("Physical Gas Requirements"), and co-sponsors Section 2.C ("Energy Requirements"). He also sponsors Technical Appendix ECON-1.

Timothy Pollard, Director of Load Forecasting. Mr. Pollard sponsors the load forecast, which is described in Section 2.A of the ESP narrative.

Lindsey Schlekeway, Director of Market Policy. Ms. Schlekeway sponsors portions of Section 3.A. ("Market Fundamentals") of the ESP update which relate to regional market development and the Western Resource Adequacy Program ("WRAP").

Sean Spitzer, Director of Renewable Energy and Origination. Mr. Spitzer sponsors the Renewable Energy Planning section, Section 2.D.

Matthew Valentic, Revenue Requirement and FERC Manager. Mr. Valentic sponsors Technical Appendix Item GAS-2, which provides actual and forecasted Base Tariff Energy Rates ("BTER") and Deferred Energy Accounting Adjustment ("DEAA") components.

Vincent Vitiello, Gas Supply Planning Lead. Mr. Vitiello sponsors Section 5.B ("Gas Transportation Plan").

Zeljko Vukanovic, Market Fundamentals Lead. Mr. Vukanovic sponsors Section 3.A ("Market Fundamentals") – except Regional Market Development – and Section 3.B ("Fuel and Purchased Power Price Forecasts") and also Technical Appendix FPP-1.

8. Q. PLEASE SUMMARIZE THE COMPANIES' REQUESTS IN THIS ANNUAL ESP UPDATE.

A. First, and most generally, the Companies ask that the Commission approve and accept the ESP Update and, pursuant to the Commission's regulations, find that the elements of the ESP – the purchased power procurement plan, the fuel procurement plan, and the risk management strategy – and the components of those elements are prudent.

Second, and more specifically, the Companies request that the Commission make the following findings:

- That the ESP Update 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.
- That the ESP Update optimizes the value of the overall supply portfolio of the Companies for the benefit of their bundled retail customers.
- That the ESP Update does not contain any feature or mechanism that would impair the Companies' creditworthiness or would lead to a deterioration of the Companies' creditworthiness.

Third, the Companies request that the Commission make the following findings and issue the following approvals:

Loads and Resources: A finding that the load forecast used in this ESP Update meets the requirements of the NAC and is suitable for making planning decisions during the remainder of the ESP action plan period (2026-2027).

Power Procurement/Sales Plans: Acceptance and approval of the power procurement/sales plan, and an affirmative finding consistent with NAC § 704.9494(3) that the power procurement strategy is prudent. The Companies request acceptance and approval of their plan to continue to implement a four-season laddering strategy for physical energy and/or capacity procurement to manage the open capacity position.

Fuel Procurement Plans:

Physical Gas Procurement Plan: The Companies request acceptance and approval of the plan to continue to implement their four-season laddering strategy for physical gas supply, and an affirmative finding consistent with NAC § 704.9494(3) that the physical gas procurement strategy is prudent.

Gas Transportation Plan: The Companies request acceptance and approval of the gas transportation plan, and an affirmative finding consistent with NAC § 704.9494(3) that the gas transportation strategy is prudent.

Gas Hedging Plan: The Companies request acceptance and approval of the gas hedging plan, which continues the current hedging strategy pursuant to which the Companies will not acquire natural gas hedges during the ESP action plan period, and an affirmative finding consistent with NAC § 704.9494(3) that the gas hedging strategy is prudent.

Coal Procurement Plan: The Companies request acceptance and approval of the Coal Procurement Plan, and an affirmative finding consistent with NAC § 704.9494(3) that the coal procurement strategy for the Valmy station is prudent.

Risk Management Strategy: The Companies request acceptance and approval of the risk management strategy and a finding that the strategy identifies risks inherent in procuring and obtaining a supply portfolio and establishes the means by which the Companies plan to address and balance or hedge the identified risks related to cost, price volatility and reliability. The Companies request an affirmative finding consistent with NAC § 704.9494(3) that the risk management strategy is prudent.

Directives: The Companies request a finding that they have satisfied their obligations to continue to hold bi-annual workshops with Staff and BCP and provide updates in the form of presentations to review the implementation of the constituent elements of the ESP and ESP updates, and the approved hedging strategy as contained in the Commission's order dated October 17, 2019, in Docket No. 19-08034.

9. Q. HOW DO THE COMPANIES PREPARE AN ESP UPDATE?

A. The ESP Update is a short-term plan covering the first three years of a triennial integrated resource plan ("IRP"). This update to the 2024 ESP covers the 2026-2027 period – the remaining years of the 2024 ESP. The Companies used the load forecast to project customers' energy needs, including appropriate planning reserve margins. Once those needs are known, the Companies then assess the options available to meet those needs. The process includes an examination of market fundamentals in the region, including the outlook for change over the planning horizon. The Companies then identify resource options such as market purchases, including the type or mix of products, company-owned resources, and long-term power purchase agreements that are available to meet identified needs. The resource options are evaluated against three criteria: 1) minimizing the cost of supply, 2) minimizing retail price volatility, and 3) maximizing the reliability of energy supply over the term of the ESP. The Companies also consider the need to comply with Nevada's Renewable Portfolio Standard ("RPS"), whether the ESP Update optimizes the value of the overall supply portfolio for the benefit of customers, and whether the ESP Update contains any feature or mechanism that would impair the restoration of the Companies' creditworthiness or would lead to a deterioration of the Companies' creditworthiness.

10. Q. WHAT PRINCIPLES GUIDED THE COMPANIES IN THE DEVELOPMENT OF THIS ESP?

A. The following principles guide the Companies' preparation of this ESP.

1) **Manage Exposure to Volatile Wholesale Energy Markets**. The Companies' strategies generally include executing longer-term contracts where appropriate in order to reduce customer exposure to price volatility on the capacity portion of NV Energy's energy supply costs.

2) **Utilize Competitive Procurement Processes**. The Companies use request for proposals ("RFPs"), or other tools, designed to produce competitive offers so that the Companies procure necessary resources in a manner that yields just and reasonable rates. RFPs provide flexibility to adjust the contracted amount based on the reasonableness of the offers that are received. An experienced team evaluates the proposals that are received, and determines the contract awards based upon price, reliability, and other competitive factors. The Companies' procedures are designed to ensure that customers pay fair market value for the commodities that the Companies purchase on their behalf.

3) **Continuous Evaluation and Monitoring**. The Companies continuously assess their procurement plans and strategies based upon changing market conditions and needs. The Risk Committee reviews supply plans approximately once a month. As a further check on the costs and benefits of the approved ESP and ESP Updates throughout the implementation process, the Risk Control organization monitors the energy costs and customer value at risk against set limits on a monthly basis, and reports variances to the Risk Committee. To the extent that circumstances dictate a change in strategy, the Resource Planning organization alerts the Risk Committee, notifies Staff and BCP, and obtains appropriate approvals of such deviations where applicable.

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

A. Yes.

EXHIBIT WELLS-DIRECT-1

Janet C. Wells
Vice President of Regulatory
Rates and Regulatory Affairs
NV Energy
6100 Neil Road
Reno, Nevada 89511-1137
(775) 834-4135

Mrs. Wells has been an employee of NV Energy for eighteen years and her time at the company includes her previous positions as Vice President of Regulatory, Regulatory Policy Director, Manager of Load Research, Senior Economist and Staff Economist in the Rates and Regulatory Affairs department and her current position as Vice President of Integrated Resource Planning. Her current responsibilities are focused on the analytical and strategic approaches to the planning functions of NV Energy.

Prior to joining NV Energy, Mrs. Wells had experience in economic consulting and research in both corporate and academic environments, detailed below, as well as other non-profit business experience not specifically detailed below.

Employment History **NV Energy**
October 2011 to Present December 2000 to August 2005

Vice President of Integrated Resource Planning
February 2024 to present

- Lead the distribution, transmission and resource planning teams in addition to load forecasting and research analyses.

Vice President of Regulatory
May 2022 to February 2024

- Oversee the preparation of regulatory filings before the Public Utilities Commission of Nevada and specifically the Load Research, Pricing, and Regulatory Affairs technical teams.

Regulatory Policy Director, Rates and Regulatory Affairs
March 2020 to April 2022

- Direct analytical and strategic approaches to regulatory issues and filings as well as corporate deliverables. Conduct research and analysis in support of new regulatory initiatives. Collaborate with regulatory groups in developing analysis and strategic approaches to integrating regulatory, load research, load forecasting, and pricing.
- Continue to support the management and technical production of class loads and other regulatory filings employing load data analyses.

Manager, Load Research, Rates and Regulatory Affairs
April 2017 to February 2020

Supervisor, Load Research, Rates and Regulatory Affairs
July 2012 to March 2017

- Manage all data and analysis related to producing hourly class loads for all Nevada Power and Sierra Pacific customer classes. Specifically, this process includes verification and estimation of interval data from multiple systems, population identification and validation, statistical sampling from populations, expansion of sample classes to produce class level total loads, and verification of final class loads to historical loads.

- Support all regulatory filings and data requests with load data and analysis ranging from: providing actual data, drafting responses, providing feedback to responses, and documenting completed analysis. Write and support testimony as needed.
- Provide validated load data and analysis to numerous areas within the company including Major Accounts, Load Forecasting, Energy Efficiency, Billing, Contracts, and to specific projects within the company such as the Energy Imbalance Market and Advanced Metering Infrastructure. In addition, provide validated load data where appropriate for external requests.
- Provide expertise and support to other major projects related to load data management and analysis including all work from raw data integrations and management, customer specific deliverables, original programming to produce needed calculations, and both data and statistical support of final analyses and report writing for projects such as the Nevada Dynamic Pricing Trial (NDPT)

Senior Economist, Advanced Service Delivery Project
October 2011 to July 2012

- Managed statistical sampling for U.S. Department of Energy reporting on metrics and recruitment
- Contributed to development of statistical design for analysis
- Managed data integrations needed for implementation of project

Staff Economist, Rates and Regulatory Affairs
October 2001 to August 2005

- Updated the Nevada Power Cost of Service Study as an input to rate cases
- Updated Customer Weighting Factor Study for Nevada Power and Sierra Pacific as an input to rate cases
- Supported all regulatory filings with testimony review and responses to data requests

Senior Economist, Rates and Regulatory Affairs
December 2000 to October 2001

- Developed Nevada Power Cost of Service Study as an input to rate cases
- Developed automated system for completing Customer Weighting Factor Studies

<u>Other Related Employment</u> **University of Nevada, Reno** May 2005 to August 2006

Research Associate

- Developed statistical programs for data management and analysis of 20 years of data to assess the Economic Value of Hiking for publication in a book chapter
- Developed survey instrument, data management from the survey, and econometric analysis related to wild horse adoption

Triangle Economic Research, Durham, NC
July 1997 to December 2000

Senior Economist, March 2000-December 2000
Economist, July 1997-March 2000

- Prepared preliminary estimate of recreational fishing damages from hazardous substance release using revealed preference data in a random utility model
- Estimated random utility models to determine expected catch using multiple methods, including non-parametric estimation and a multinomial logit estimation of catch (presented at American Agricultural Economics Association annual meeting)
- Developed and administered survey of recreational boaters; acquired survey research firm and validated data. Developed analysis plan for probit model of probability of site choice and conditional logit model of recreational benefits from restoration projects. Results were published with estimates of recreational benefits from proposed restoration projects using benefit transfer from other cases in Arizona Law Review
- Completed data collection, data management, econometric modeling and analysis, and report writing to estimate aggregate values of recreational activities using a nested price index, published in Environmental and Resource Economics

Prior Testimony Before Public Utilities Commissions
PUCN Docket Nos.: 15-07041, 15-07042, 16-06006, 17-06003, 17-06014, 17-06015, 18-08007, 18-10034, 19-02002, 19-04002, 19-06002, 20-06003, 21-09031, 21-09032, 22-06014, 22-09002, 22-09006, 22-11032, 23-02010, 23-02011, 23-06007, 23-08019, 24-02026, 24-02027, 24-05022, 24-05023, 24-05041, 24-06011, 24-06012, 24-06014, 25-01018, 25-01019, 25-02016, and 25-02033.

Education
University of Nevada, Reno
Master of Applied Economics and Statistics, August 1996

University of Manitoba, Winnipeg, Manitoba
Bachelor of Arts in Geography, June 1992

Continuing Education
NERA Marginal Cost Methodology for Electric Utilities SAS Programming I and II
CORE Leadership Training
Six Sigma Green Belt Certification

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, JANET WELLS, 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: August 29, 2025

JANET WELLS

CATALIN ADRIAN CACUCI

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

2025 Joint Energy Supply Plan Update
Docket No. 25-08___

Prepared Direct Testimony of

Catalin Adrian Cacuci

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

A. My name is Catalin Adrian Cacuci. My current position is Treasurer 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 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. I joined the Companies in 2022 as Assistant Treasurer and became Treasurer in 2023. Prior to joining the Companies, I held the position of Treasurer at The Cosmopolitan of Las Vegas since the property opened in 2010. In addition to the Treasurer role, I have held the roles of Vice President of Finance, Executive Director of Finance, Senior Director of Financial Planning and Analysis, and Director of Operational Analysis. Prior to The Cosmopolitan, I worked in Treasury and Financial Planning and Analysis at MGM Resorts International and Caesars' Entertainment corporate and various properties, respectively. I have undergraduate

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

and graduate degrees in business with an emphasis in finance. Additional details regarding my professional background and experience are in my Statement of Qualifications which was provided as **Exhibit Cacuci-Direct-1.**

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

A. As Treasurer, my responsibilities include oversight of the treasury and risk control-related functions. Treasury-related responsibilities include assisting the Chief Financial Officer to ensure adequacy of liquidity and financial stability including long-term financing and short-term debt utilization for the Companies.

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

A. Yes. I have previously prepared testimony in proceedings before the Commission, including in the Joint Energy Supply Plan Update for 2023 and the Energy Supply Plan filed in 2024, Docket Nos. 23-09003 and 24-05041, respectively.

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

A. I sponsor Section 7 ("Risk Management Strategy") and portions of Section 8 ("Determination of Prudence") of the Companies' 2025 Joint Energy Supply Plan Update ("ESP Update"), which covers the two year period from 2026 through 2027. I sponsor the following Technical Appendices:

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

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

A. I sponsor the following exhibit:

Exhibit Cacuci-Direct-1 – Statement of Qualifications

7. Q. **PLEASE DESCRIBE THE POLICIES THAT GOVERN THE COMPANIES' RISK CONTROL FUNCTION.**

A. The Companies' risk control policies are as follows:

- RM-1: Risk Management and Control Policy is the Companies' umbrella document that defines corporate risks, describes the management of that risk, and creates a governance structure (including the Risk Committee) to oversee policy implementation and adherence;
- RM-2: Energy Risk Management and Control Policy relates specifically to physical and financial transactions related to energy procurement, sales, and hedging. This policy establishes governance structures, authorized signatories, risk control thresholds, and compliance, among other items; and
- RM-3: Credit Risk Management and Control Policy provides an overview of the Companies' definition and management of risk created by a counterparty's inability or unwillingness to fulfill its contractual obligations.

8. Q. **PLEASE DESCRIBE THE COMPANIES' RISK MANAGEMENT FUNCTION AND CONTROL STRUCTURE.**

A. The policies create the framework for managing risk, including four functional areas that are important components of risk management and control activities. They are:

1) **Risk Committee.** The Risk Committee is the executive team responsible for the overall policy direction and administration of the Companies' integrated

risk control activities. The Risk Committee serves as the mechanism through which the executive management team is kept apprised of inherent risks. The Risk Committee is also responsible for monitoring risk management and control efforts relative to fuel and wholesale power. The members of the Risk Committee are listed in the Risk Management and Control Policy (See RM-1, Section V, subsection B).

2) **Risk Control**. The Risk Control function is responsible for monitoring compliance with established risk policies and associated procedures, including the approved ESP. Risk Control is also responsible for evaluating and reporting the energy supply portfolio risk control metrics discussed later in this testimony.

3) **Credit Risk Management**. Credit risk is defined as the possibility that a counterparty will be unable or unwilling to timely fulfill its financial or physical obligations to the Companies because of the counterparty's financial condition. Credit Risk Management generally is responsible for credit risk management activities as they apply to energy supply.

4) **Energy Supply**. Energy Supply, under direction of the Vice President, Integrated Resource Planning, Vice President, Generation and Vice President, Resource Optimization, are responsible for the generation production, delivery and optimization of fuel and wholesale power transactions.

9. Q. WHAT ARE THE RISK COMMITTEE'S ENERGY SUPPLY RELATED RESPONSIBILITIES?

A. The Risk Committee has several key responsibilities regarding energy supply risks. These include:

- Assessing the appropriateness of the Companies' energy supply risk management and control activities and making recommendations for modifications to existing risk policies;
- Approving changes and exceptions as designated in specific sections of the risk policies and ensuring the ongoing availability of procedures required to implement those policies or any changes to them;
- Assessing the systems required to monitor, record, and report on the risks inherent in the Companies' energy supply related activities and making recommendations for improvements to existing policies;
- Approving ESPs, ESP Updates and any exceptions to these plans;
- Reviewing all transactions requiring exceptions to the applicable policies and procedures;
- Reviewing all energy procurement and sale transactions that are not transacted in accordance with the ESP or ESP updates prior to the submission for approval of such transactions to the President;
- Reviewing all violations of notification thresholds and processes established under the risk policies, approving or recommending for approval remedies of the violations, and monitoring progress of such remedies; and
- Assigning the completion of any other activities to guide the overall policy direction of the Companies' energy risk management and control efforts.

10. Q. WHAT TYPES OF FORMAL METRICS HAVE BEEN ESTABLISHED BY THE RISK COMMITTEE FOR EVALUATING THE COMPANIES' ENERGY SUPPLY PORTFOLIOS?

A. Three types of risk control metrics are utilized: transaction approval metrics, portfolio risk metrics, and credit risk metrics.

11. Q. PLEASE DESCRIBE THE TRANSACTION APPROVAL METRICS THAT ARE USED TO ASSIST THE RISK COMMITTEE IN EVALUATING THE COMPANIES' PORTFOLIOS.

A. The transaction approval metrics control the values of contracts that authorized personnel are allowed to execute. Total dollar value of the contract is tracked and reported.

12. Q. PLEASE DESCRIBE THE PORTFOLIO RISK METRICS THAT ARE USED TO ASSIST THE RISK COMMITTEE IN EVALUATING THE COMPANIES' PORTFOLIOS.

A. The Energy Risk Management and Control Policy defines the use of the following two metrics:

1) **Test Period Mark-to-Base**. Monthly differences between fuel and purchased power costs and Base Tariff Energy Rate revenues are deferred. Mark-to-Base provides an estimate of such deferrals for the current deferral period. Mark-to-Base is determined using actual expenditures to date, committed expenditures for the balance of the deferral period, and expected expenditures for uncommitted purchases. The policy triggers notifications if significant changes in Mark-to-Base are experienced on either a cumulative basis or on a month-to-month basis.

2) **Value-at-Risk**. Value-at-Risk serves as a gauge of market exposure, summarizing the total market risk on the Companies' fuel and purchased power costs. As measured by the Companies, Value-at-Risk estimates the increase in fuel and wholesale power costs over the forthcoming rolling 12-months at a 95 percent confidence interval. Value-at-Risk is a useful tool in determining liquidity requirements and is referred to as cash flow at risk when used in this

context. The Energy Risk Management and Control Policy triggers notifications if Value-at-Risk exceeds certain levels. A 95 percent confidence interval means that there is a 95 percent probability that actual fuel and purchased power expenses will not exceed the Value-at-Risk projection. However, there is still a 5 percent probability that the increased costs will be higher than the Value-at-Risk projection. The idea is to measure, within a 95 percent degree of probability, the potential increase in costs to customers.

Inputs used to calculate Value-at-Risk include the forward price curves for power and natural gas, as well as the associated forward monthly volatilities of each product. Correlations between the various power and gas trading hubs are calculated based on historical prices at each trading hub. A distribution of possible forward price outcomes is then generated and standard statistical methods are applied to evaluate portfolio impacts at various confidence intervals.

13. Q. PLEASE DESCRIBE THE CREDIT RISK METRICS THAT ARE USED TO ASSIST THE RISK COMMITTEE IN EVALUATING THE COMPANIES' PORTFOLIOS.

A. Credit limits help to ensure that the Companies are not overly exposed to any single counterparty or to a counterparty with unacceptable credit profiles. The Credit Risk Management and Control Policy identifies four credit limits that are monitored monthly:

1) **Portfolio Below Investment Grade.** The percentage of actual mark-to-market exposure below investment grade for the portfolio as of prior month's end;

2) **Portfolio Weighted Average Credit Rating.** The weighted average of actual mark-to-market exposure for the portfolio as of prior month's end;

3) **Counterparty Credit Limit On-going Transactions.** The actual mark-to-market exposure of counterparties at prior month's end; and

4) **Counterparty Credit Limits Large Transactions.** The potential mark-to-market exposure of counterparties with transactions greater than $10 million entered into in the past month.

14. Q. PLEASE DESCRIBE THE RISK CONTROL FUNCTION.

A. Risk Control is a distinct organization within the Companies and is responsible for calculating certain risk control metrics. Representatives of the Risk Control organization report the results of these analyses to management in a Monthly Risk Control Report. Risk Control also performs actualization of fuel and power transactions prior to invoices being paid to counterparties. Additionally, Risk Control monitors recorded conversations of fuel and power traders via phone, instant message and other channels to check for any signs of fraud.

15. Q. PLEASE DESCRIBE THE MONTHLY RISK CONTROL REPORTS.

A. The Risk Control organization prepares monthly reports to identify, track and report risk control metrics relating to transaction approval risk, portfolio risk, and credit risk. The reports are presented and discussed at meetings of the Risk Committee.

16. Q. PLEASE DEFINE THE TERM 'NOTIFICATION THRESHOLD' AS IT IS USED IN THE RISK CONTROL REPORTING PROCESS.

A. A 'notification threshold' triggers reports to management when certain threshold events occur, such as a large increase in the Mark-to-Base. The notification thresholds require management notification and discussion. After notification and discussion, management must decide whether or not to take specific actions in response to the event that triggered the notification.

17. Q. WHAT HAPPENS WHEN THE RISK CONTROL ORGANIZATION REPORTS AN EVENT THAT TRIGGERS A NOTIFICATION REQUIREMENT?

A. Several steps are taken upon a triggering event:

- Upon identification of an event triggering a notification requirement, the Treasurer or a designated Risk Control employee will notify the appropriate officer, and, depending upon the nature of the issue, can call for a special Risk Committee meeting;
- Risk Control maintains a log of all notifications and monitors the status of each issue until compliance is achieved; and
- Risk Control presents all events triggering a notification requirement to the Risk Committee for discussion, including a recommended course of corrective action if deemed necessary.

18. Q. PLEASE DESCRIBE THE CREDIT RISK MANAGEMENT FUNCTION.

A. The Credit Risk Management and Control Policy establishes a set of metrics that are monitored by Risk Control on a periodic basis. The purpose of these metrics is to provide transparency of the corporate credit portfolio to the Risk Committee. The metrics include an Arrears Balance Metric and an Uncollected Deposits Metric, each designed to monitor the credit exposure attributable to large retail customers. In addition, a counterparty credit metric for supply chain is used to control the credit exposure attributable to large suppliers.

All potential transactions are reviewed to determine counterparty credit ratings, financial scoring metrics, the current mark-to-market exposure of all current transactions, and whether the potential credit exposure calculations are within the Companies' policy limits. The Credit Risk Management function is responsible for assessing and approving the credit risk of counterparties and is also responsible for data collection and reporting of the creditworthiness of current and potential counterparties on an ongoing basis. A monthly report tracks current counterparties, their credit ratings from Moody's and Standard and Poor's, the outlook of the ratings, the internal credit limit of each counterparty based on the lowest of the two ratings, and the mark-to-market exposure. This credit report is distributed to the Companies' management, and, based upon these reports, stricter counterparty limits will be put in place if appropriate. The Credit Risk Management function is also responsible for providing collateral requirements for fuel and power contracts.

19. Q. WHAT HAPPENS IF A COUNTERPARTY'S CREDIT IS DOWNGRADED AFTER A CONTRACT IS SIGNED?

A. If a counterparty is downgraded after a contract is signed, Credit Risk Management monitors the performance and the exposure of the contract in relation to the credit limit. The contracts themselves provide the Companies and customers with protection in the form of monetary damages in the event of certain credit events and if the delivery obligation is not fulfilled. Depending on the nature of the credit event and contract exposure, the counterparty can be deactivated for additional transactions.

20. Q. PLEASE SUMMARIZE THE ROLE OF THE ENERGY SUPPLY GROUP IN THE ENERGY RISK MANAGEMENT PROGRAM.

A. The Energy Supply organization manages energy risk by purchasing and selling financial instruments and physical products in accordance with an approved ESP. The ESP and ESP updates are reviewed on an ongoing basis and updated at least annually. Material changes in the data or assumptions underlying the approved ESP, which may also require a change in strategy, are promptly reported to the Risk Committee by Resource Planning & Analysis..

21. Q. WHAT PORTIONS OF SECTION 8 OF THE ESP DO YOU SPONSOR?

A. Section 8 of the 2024 ESP addresses the three criteria set forth in Nevada Administrative Code, section 704.9494, which are to be applied by the Commission in making a determination that the ESP is prudent:

- 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.

I address the third criterion, relating to the Companies' creditworthiness.

22. Q. **PLEASE SUMMARIZE THE COMPANIES' CURRENT CREDIT RATINGS.**

A. On October 18, 2024, Standard & Poor's Ratings Services ('S&P') affirmed Sierra's 'A-' issuer rating and stable outlook. S&P noted that because the company is considered a strategically important subsidiary of Berkshire Hathaway Energy the issuer rating is two notches above what it would be rated on a stand-alone basis. On January 30, 2025, S&P affirmed Nevada Power's 'A-' issuer rating and stable outlook and assigned a 'BBB' rating to the Company's new Junior Subordinated Notes ('JSN') issuance.

On January 30, 2025, Moody's affirmed Nevada Power's ratings and stable outlook and assigned a 'Baa2' rating to the Company's new JSN issuance. On January 31, 2025, Moody's Investors Service re-affirmed Nevada Power's 'Baa1' Issuer credit rating and on June 30, 2025 it reaffirmed Sierra's 'Baa2' Issuer credit rating. In the case of Sierra, Moody's recognized that the Company is undergoing significant capital expenditures related to the Sierra Solar and Greenlink projects and noted that regulatory lag is more pronounced in Nevada due to reliance on a regulatory framework which does not include a forward test year or capital cost recovery mechanism. Moody's lists several factors that could lead to a downgrade at Sierra including a decrease in the CFO pre-WC to debt ratio to 14% or below on a sustained basis, insufficient parent support, or unfavorable regulatory recovery treatment.

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

Table Cacuci-Direct-1 below shows each rating for each respective company.

TABLE CACUCI-DIRECT-1

	S&P – STABLE			Moody's – STABLE		
Ratings	Issuer	Senior Secured	Junior Subordinated	Issuer	Senior Secured	Junior Subordinated
Nevada Power	A-	A	BBB+	Baa1	A2	Baa2
Sierra	A-	A	n/a	Baa2	A3	n/a

23. Q. DOES THE 2025 ESP UPDATE CONTAIN ANY FEATURE OR MECHANISM THAT WOULD IMPAIR THE RESTORATION OF THE CREDITWORTHINESS OF THE COMPANIES OR THAT COULD BE REASONABLY EXPECTED TO IMPAIR OR ERODE THE CREDITWORTHINESS OF THE COMPANIES?

A. No, the Companies' creditworthiness improved materially following the acquisition by Berkshire Hathaway Energy Company in 2013. S&P's revised its rating methodology in 2016 which resulted in Nevada Power and Sierra's credit ratings being raised above the ratings assigned by S&P's to these entities at the time of the 2013 acquisition.

Credit quality can be impacted by the funding requirements associated with capital expenditures and by financial commitments created by contracts, such as power purchase agreements ("PPAs"). The impact on credit quality from funding requirements associated with capital expenditures can be estimated using changes in equity and debt capital balances and cash flow amounts. PPAs are also part of the rating agencies' evaluation process and have the potential to negatively impact credit ratings, depending on the magnitude and terms of a utility's PPA portfolio, other pending uncertainties, and issuer mitigation strategies.

24. Q. THE 2025 ESP UPDATE PROPOSES A NATURAL GAS HEDGING STRATEGY WHEREBY THE COMPANIES WOULD NOT PROCURE ANY HEDGES DURING THE ESP FORECAST PERIOD. WOULD THIS STRATEGY IMPAIR THE CREDITWORTHINESS OF THE COMPANIES?

A. The strategy, in and of itself, does not impair the Companies' creditworthiness; significant under collection of fuel and purchase power costs due to increasing natural gas prices and the limitations of the recovery mechanism can create pressure as seen recently with increases in the deferred energy balance. Nevertheless, the Companies do not believe the mechanism itself has a negative impact on creditworthiness. The Companies have historically relied upon internally generated cash flow, existing cash balances, and capacity under their revolving credit facilities to fund fuel and power expenditures.

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

A. Yes.

EXHIBIT CACUCI-DIRECT-1

CATALIN ADRIAN CACUCI
TREASURER
NV Energy
6226 West Sahara Avenue
Las Vegas, NV 89151

Summary of Qualifications

I have been employed at NV Energy since September 2022 with primary responsibilities in Treasury and Risk Control. I have 21 years of experience in Treasury, Corporate Finance, and Financial Planning and Analysis.

Professional Experience

NV Energy – Treasurer *(2022-Current)*
Primary responsibilities in Treasury and Risk Control. Other positions held: Interim Treasurer, Assistant Treasurer

The Cosmopolitan of Las Vegas – Vice President of Finance and Treasurer *(2010-2022)*
Oversaw all treasury and payables functions. Other positions held: Executive Director of Finance, Sr. Director Financial Planning and Analysis, Director of Operational Analysis, HOA President, HOA Treasurer

MGM Resorts International – Treasury Manager *(2006-2010)*
Oversaw daily cash management and reporting, bank relationship management, cash liquidity, corporate card programs, merchant services, employee stock compensation plan

New York, New York Hotel and Casino – Financial Planning and Analysis Manager *(2005-2006)*
Managed FP&A functions including annual operational and capital budgets, strategic plans, return on investment analysis, evaluated host and independent agent efficiency, labor standards and productivity, special event proformas and post event analysis

Caesars' Entertainment – Senior Financial Analyst *(2003-2005)*
Prepared and analyzed annual operating and capital budgets, labor standards, gaming host and independent agent productivity, commission reports, individual player activity reports, special event proformas and post event analysis

Education and Certification

University of Nevada, Las Vegas – Master of Business Administration
Two-year program with a concentration in finance

University of Nevada, Las Vegas – Bachelor of Science in International Business
Summa Cum Laude

Association for Financial Professionals - Certified Treasury Professional (CTP)
Issued 2012, Active status

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, CATALIN ADRIAN CACUCI, 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: August 29, 2025

CATALIN ADRIAN CACUCI

MICHAEL HOLLAND

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

2025 Energy Supply Plan Update
Docket No. 25-08___

Prepared Direct Testimony of

Michael Holland

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

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

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

A. My experience includes more than 16 years in the energy sector with positions in several areas, including power and natural gas trading and the oversight of energy trading activities in multiple markets. I have been in various leadership roles overseeing activities related to energy trading, retail natural gas and electric supply, origination and market operations. More details regarding my background and experience are provided in **Exhibit Holland-Direct-1.**

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

A. My current responsibilities involve the oversight of the Resource Optimization Department, which is responsible for a number of activities, including, but not limited to, all power and natural gas trading activities, coal procurement, participation in the Western Energy Imbalance Market ("EIM"), resource origination, contract management, and wholesale market design efforts.

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

A. Yes. I have previously prepared testimony in proceedings before the Commission in Nevada Power's General Rate Case filing in Docket No. 25-02016 and in the Companies' recent Deferred Energy Accounting Adjustment filings, Docket Nos. 25-02033, 25-02034, and 25-02035.

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

A. As the 2025 Energy Supply Plan Update ("ESP Update") witness, I sponsor or co-sponsor the following sections in the Companies' ESP Update:

- Section 2.C ("Energy Requirements");
- Section 2.G ("Financial Gas Requirements");
- Section 4 ("Power Procurement Plan");
- Section 5.A ("Physical Gas Procurement Plan");
- Section 5.C ("Recommended Gas Hedging Plan");
- Section 6. Coal and Valmy Closure; and
- Technical Appendix GAS-1.

6. Q. ARE YOU SPONSORING ANY TECHNICAL APPENDIX ITEMS?

A. Yes, I am sponsoring the following Technical Appendices:

- GAS-1- Gas Hedging Workshop Presentations.

7. Q. PLEASE DESCRIBE THE COMPANIES' POWER PROCUREMENT PLAN.

A. In 2017, the Commission accepted stipulations resolving all matters in the Companies' 2017 ESP update applications in Docket Nos. 17-09001 and 17-09002, including the power procurement plan strategies. In compliance with the approved power procurement plan, in January 2018 the Companies issued the first of several request for proposals ("RFP") to procure energy and/or capacity to implement a four-season laddering strategy to close the open position. In this filing, the Companies are requesting approval to continue with the four-season laddering strategy to close the open position.

The four-season power procurement plan for managing the open position will utilize a competitive bidding process scheduled to coordinate with the Companies' physical natural gas procurement plan. The procurement percentages are shown in **Table Holland-Direct-1**.

TABLE HOLLAND-DIRECT-1
PERCENTAGE OF OPEN POWER POSITION TO BE CLOSED IN EACH PROCUREMENT PERIOD

Incremental transaction	Delivery				
	Summer 2025	Summer 2026	Summer 2027	Summer 2028	Summer 2029
Q3 2023	25%				
Q1 2024	25%				
Q3 2024	25%	25%			
Q1 2025	25%	25%			
Q3 2025		25%	25%		
Q1 2026		25%	25%		
Q3 2026			25%	25%	
Q1 2027			25%	25%	
Q3 2027				25%	25%
Sum	100%	100%	100%	75%	25%

In addition to the RFP process, the Companies propose to continue to work directly with counterparties to solicit non-standard products, which may more cost-effectively address the short-term (two to three hour) jumps in open capacity due to drastic drops in renewable resources in the evening hours. The Companies will evaluate all available products and determine the most prudent transaction plan based on cost and deliverability.

8. Q. ARE THE COMPANIES CONCERNED ABOUT THEIR ABILITY TO OBTAIN SUFFICIENT RELIABLE ENERGY TO FILL ANY ADDITIONAL OPEN POSITIONS THAT MAY OCCUR DURING THE ESP UPDATE FORECAST PERIOD DUE TO UNANTICIPATED INCREASES IN ENERGY DEMAND AND/OR SHORTAGES IN SUPPLY?

A. Yes. As noted in recent filings, western energy markets are experiencing rapid and significant changes in climate, weather, resource mix, policy, and energy consumption patterns, requiring the Companies and stakeholders to reevaluate established practices, in particular, large reliance on market purchases, to ensure sufficient capacity to meet peak demands during the summer. Climate-related incidents and record load levels are no longer isolated occurrences, but rather annual events. Both the Western Electric Coordinating Council and the North American Electric Reliability Corporation have issued resource adequacy and reliability cautionary statements regarding the uncertain availability and deliverability of market capacity and energy due to more frequent extreme weather, weather-related events, and a changing climate that are stressing the system.

9. Q. WHAT IS THE STATUS OF THE WESTERN RESOURCE ADEQUACY PROGRAM ("WRAP") AND DAY-AHEAD MARKET DEVELOPMENT?

A. The Companies' witness Lindsay Schlekeway addresses the status of the WRAP and Extended Day-Ahead market development.

10. Q. PLEASE DESCRIBE THE COMPANIES' PHYSICAL GAS PROCUREMENT PLAN.

A. Section 5.A of the ESP Update summarizes the Companies' physical gas procurement plan. The Companies are requesting acceptance and approval of their plan to continue to procure physical gas using the four-season laddering strategy originally approved by the Commission in Docket No. 09-09001, and most recently reaffirmed by the Commission in Docket No. 24-05041. Pursuant to the four-season laddering strategy, the Companies will procure 25 percent of projected monthly physical gas requirements per season for four seasons, subject to the availability of conforming bids and the willingness of suppliers to accept reasonable commercial terms. Furthermore, targeted physical gas volumes will exclude any potential gas-fired generation to meet forward sales; gas needed to meet forward sales will only be procured in the short-term.

TABLE HOLLAND-DIRECT-2
PHYSICAL GAS ACQUISITION STRATEGY

	Delivery								
Incremental Transaction	Summer '25	Winter '25-'26	Summer '26	Winter '26-'27	Summer '27	Winter '27-'28	Summer '28	Winter '28-'29	Summer '29
Q1 '23									
Q3 '23	25%								
Q1 '24	25%	25%							
Q3 '24	25%	25%	25%						
Q1 '25	25%	25%	25%	25%					
Q3 '25		25%	25%	25%	25%				
Q1 '26			25%	25%	25%	25%			
Q3 '26				25%	25%	25%	25%		
Q1 '27					25%	25%	25%	25%	
Q3 '27						25%	25%	25%	25%
Sum	100%	100%	100%	100%	100%	100%	75%	50%	25%

Note: Winter includes the months of November through March and Summer includes the months of April through October.

11. Q. PLEASE BRIEFLY DESCRIBE COMPANIES' NATURAL GAS HEDGING PLAN.

A. The Companies propose to continue the currently approved hedging strategy and acquire no natural gas hedges covering the ESP Update action plan period at this time. The Companies will continue to monitor the gas markets and propose a revised hedging strategy, if necessary, in a future ESP amendment or ESP update. The Companies will also participate in the investigation and rulemaking docket No. 25-07003, which is the result of Assembly Bill 452 (2025), and will be prepared to implement any outcome from that docket.

12. Q. DOES SIERRA CURRENTLY HAVE ANY COAL SUPPLY COMMITMENTS?

A. Sierra currently has coal purchase agreements in place to provide sufficient supply until the Valmy units cease coal operations at the end of 2025. Due to the planned 2025 coal-to-gas conversion date of both Valmy units, Sierra will not solicit or enter into any longer-term coal supply agreements.

13. Q. WHAT IS PORTFOLIO OPTIMIZATION?

A. Portfolio optimization involves structuring the Companies' portfolio of resources, including generation resources and assets, purchased power contracts, and natural gas contracts, based upon reliability considerations, economic factors, and changes in anticipated load, in a manner that minimizes costs to the Companies' customers while effectively managing risk.

14. Q. DO THE COMPANIES OPTIMIZE THEIR RESOURCE PORTFOLIOS?

A. Yes. The Companies engage in short-term (*i.e.*, less than one month) and forward (*i.e.*, greater than one month) purchases of power and natural gas when economic or as needed to serve native load. The Companies also engage in sales of power and natural gas to the extent that available resources are not expected to be needed to serve customer load. The Companies also engage in sales of natural gas transportation capacity (*i.e.*, capacity release) that is not expected to be needed to serve gas requirements. The Companies further optimize their respective power portfolio through participation in the EIM operated by CAISO. The Companies began participating in the EIM on December 1, 2015.

15. Q. HOW DO THE COMPANIES PROPOSE TO OPTIMIZE THEIR PORTFOLIOS FOR THE BENEFIT OF CUSTOMERS DURING THE ESP UPDATE PERIOD?

A. The Companies propose to continue using a mix of short-term and forward purchases and sales as part of their portfolio optimization strategy. The Companies propose to continue to optimize their portfolio through participation in the EIM. The Companies will continue their existing practices of making sales of natural gas and natural gas transport capacity to the extent that resources are not expected to be needed to serve native load.

16. Q. WILL THE COMPANIES CONTINUOUSLY REVIEW THE PORTFOLIO OPTIMIZATION STRATEGY IN LIGHT OF CHANGING MARKET CONDITIONS?

A. Yes. The Companies will review and revise the portfolio optimization strategy as appropriate in response to changing market conditions. However, the Companies will not deviate from the strategy recommended in this ESP Update without prior approval from the Companies' Risk Committee. In addition, if the Companies deviate from the ESP, they will provide appropriate notice to Staff and the BCP as required by the Commission's regulations and, if appropriate under Commission regulations or directive, seek Commission approval to continue to deviate from the ESP.

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

A. Yes.

EXHIBIT HOLLAND-DIRECT-1

STATEMENT OF QUALIFICATIONS

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

Professional Experience

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

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

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

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

NV Energy, Las Vegas, NV

Manager, Power and Gas Trading, July 2021-August 2022

- Managed a team of power traders responsible for managing both the short and long-term power positions
- Managed a team of gas traders responsible for the procurement of natural gas to supply both power plants and end-use customers
- Responsible for multiple Requests for Proposals (RFPs) yearly to ensure power and natural gas needs are met at the best price

Senior Power Trader, June 2018-July 2021

- Optimized NV Energy's generation portfolio and executed day-ahead power transactions consistent with the Company's risk management guidelines
- Administered multiple RFPs to fill seasonal power needs

Macquarie Energy, Houston. TX

Senior Real-Time Trader, November 2010-June 2018

- Traded hourly physical and virtual power in PJM, MISO, CAISO, SWPP, ERCOT, MIDC, and NYISO markets

Ameren UE, St. Louis, MO

Real-Time Power Trader, May 2008- October 2010

- Utilized various generation assets, physical trades, and virtual bids and offers to actively manage the real-time position to maximize profits and mitigate risk.

Education

Tulane University, Freeman School of Business, New Orleans, LA

Master of Business Administration – 2008

United States Naval Academy, Annapolis, MD

Bachelor of Science, English - 1999

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

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

Date: August 29, 2025

Michael Holland
MICHAEL HOLLAND

CHARLES MCCUTCHEN

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

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2025 Energy Supply Plan Update
Docket No. 25-08____

Prepared Direct Testimony of

Charles McCutchen

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

A. My name is Charles McCutchen. My current position is Production Cost Modeling 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"). My business address is 6226 West Sahara Avenue, Las Vegas, Nevada, 89146. 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 nearly seven years in the utility industry. I have been employed by the Companies since 2018, working in the Resource Optimization and Resource Planning departments. During this time, I have held roles including Portfolio Optimization Analyst II, Senior Power and Gas Trading Specialist, and Production Cost Modeling Lead. I hold a Bachelor of Science degree in Business Administration from Nebraska Wesleyan

University and a Master of Science degree in Financial Engineering from the University of Michigan. I also maintain active certifications as a Chartered Alternative Investment Analyst and Certified Financial Risk Manager. The details of my background and experience are provided in **Exhibit McCutchen-Direct-1.**

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS PRODUCTION COST MODELING LEAD.

A. As Production Cost Modeling Lead, I am responsible for assisting in the development and management of production cost models and tools to provide reports of projected energy production and associated costs. I assess the Companies' short term energy needs and lead various supply management activities including developing open capacity positions consistent with regulatory requirements and the Companies' goals and objectives.

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

A. No.

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

A. I am sponsoring the following exhibit:

Exhibit McCutchen-Direct-1 Statement of Qualifications

I am sponsoring the following Technical Appendix:

Technical Appendix-ECON-1 – Confidential

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

A. Yes. ECON-1 is being filed confidentially. 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 their fuel and purchase power suppliers.

7. Q. FOR HOW LONG DO THE COMPANIES REQUEST CONFIDENTIAL TREATMENT?

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

8. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF THE REGULATORY OPERATIONS STAFF ("STAFF") OR THE BUREAU OF CONSUMER PROTECTION ("BCP") TO FULLY INVESTIGATE THE ESP?

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.

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

A. I sponsor the following sections in the Companies' 2025 ESP Update:

- Section 2.B ("Capacity Requirements")
- Section 2.C ("Energy Requirements") (co-sponsor)

- Section 2.E ("Gas Transportation Requirements")
- Section 2.F ("Physical Gas Requirements")
- 2026-2027 Estimated Cost to Serve for the Companies in Section 8

10. Q. PLEASE DESCRIBE THE METHODOLOGY USED TO PERFORM THE ECONOMIC ANALYSIS IN THIS FILING.

A. The Companies' analysis of future resource requirements begins with the Loads and Resources Tables ("L&R Tables"). The L&R Tables indicate the capacity resources available to serve forecasted customer load including internal generation and purchases. Purchased power resources include purchases from existing and planned renewable energy projects, internal power contracts (within the Companies' system) and external power contracts (outside the Companies' system). External generation purchases require system import transmission capacity. In addition, resources in specific locations within the Companies' control area consume or reduce import capability.

Next, the Companies utilize the software tool PLEXOS for production cost modeling.[1] PLEXOS simulates the operation of the electric system and computes production costs (fuel, purchase power, variable and fixed costs to operate generation) by performing hourly, chronological, economic unit commitment and dispatch of the Companies' electric production resources and market purchases to satisfy hourly load requirements in a least cost solution over the planning period.

[1] PLEXOS is a proprietary software product that the Companies license from Energy Exemplar.

The Companies use PLEXOS to calculate the average daily gas requirements as illustrated in Figures ESP-18 and ESP-19 in Section 2.F ("Physical Gas Requirements").

The Companies also conduct scenario analysis under the low, base, and high fuel and purchased power price forecasts. The Companies then calculate the projected Base Tariff Energy Rates ("BTER") and Deferred Energy Accounting Adjustment ("DEAA") rates for 2026-2027 under the low, base, and high fuel and purchased power price forecasts. The projected BTER and DEAA rates are presented in Technical Appendix GAS-2 and sponsored by Matthew Valentic.

An additional production cost model sensitivity is used to evaluate the system reliability and projected firm gas transportation needs for northern and southern generation plants and Sierra's natural gas local distribution company. The result of this analysis is presented in Section 2.E ("Gas Transportation Requirements").

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

A. Yes, it does.

EXHIBIT McCUTCHEN-DIRECT-1

STATEMENT OF QUALIFICATIONS
CHARLES MCCUTCHEN
6226 W. Sahara Ave.
Las Vegas, Nevada 89146

EDUCATION and CERTIFICATIONS

Nebraska Wesleyan University
Bachelor of Science in Business Administration, May 1996

University of Michigan
Master of Science in Financial Engineering, May 2008

Chartered Alternative Investment Analyst (CAIA) Charterholder
Issued 2018, Active status

Certified Financial Risk Manager (FRM)
Issued 2016, Active status

Microsoft Certified Systems Administrator (MCSA)
Issued 2004, Inactive status

PROFESSIONAL EXPERIENCE

NV Energy, Las Vegas, NV
Production Cost Modeling Lead, Resource Planning and Analysis (July 2023 – Present)

- Use production cost model PLEXOS to prepare reports of projected energy production and associated costs for fuel and power procurement, as well as for budgeting fuel and purchased power costs.
- Prepare and present the Monthly Energy Supply Plan (ESP) Update to the Risk Committee. Prepare analysis, charts, tables, and language for the ESP and Business Plan.
- Migrated four studies from PCI GenTrader to PLEXOS through extensive model development, calibration, and benchmarking to ensure continuity and accuracy in simulation results.

Senior Power & Gas Trading Specialist, Resource Optimization (May 2022 – July 2023)

- Modeled NV Energy's resources in PCI GenTrader to determine unit commitment, economic dispatch, contract pricing, and to support budgetary and operational decision-making.
- Designed and implemented a comprehensive bid evaluation model using Excel VBA and advanced optimization engines to support the procurement of natural gas.
- Developed and executed analytical models for strategic purchasing of power and coal, enhancing cost-efficiency and decision-making.

Portfolio Optimization Analyst II, Resource Optimization (October 2018 – May 2022)

- Developed and maintained models in R and Excel to track the accuracy of load, temperature, battery, and solar forecasts from third-party vendors.

- Acted as primary liaison with Hitachi Energy and UL to troubleshoot forecast discrepancies and implement model improvements, enhancing operational reliability and planning accuracy.

HC Technologies, Chicago, IL
Quantitative Trader/Analyst (July 2016 – November 2016)

- Independently developed a highly profitable quantitative trading strategy in the energy and grain futures markets.
- Used R extensively to support the trading of dollar index futures and energy futures butterflies and spreads on the Chicago Mercantile Exchange (CME).

University of California, Berkeley - Haas School of Business, Berkeley, CA
Data Scientist (January 2013 – June 2016)

- Led Berkeley Trading Teams to top global placements in the Rotman International Trading Competition, the world's largest trading competition (2nd in 2015, 3rd in 2014), with consecutive wins in the Optiver Options Case and a first-place finish in the BP Commodities Case, achieved through simulation design, strategic planning, risk management guidance, and consistent team training.
- Supported the High Frequency Finance course by explaining the structure and usage of high-frequency data including NYSE TAQ, NASDAQ ITCH, and EBS currency data as well as the use of analytical packages such as OneTick and R.
- Managed the Data Lab servers and data resources through the utilization of Perl, R, and OneTick.
- Served as a principal organizer for two international data science conferences, DataLead 2014 and DataLead 2015.

Independent Proprietary Trader, Chicago, IL
Self-employed (October 2009 – December 2012)

- Traded equity options based on extensive fundamental analysis of distressed financial firms and other special situations.
- Traded five major currency pairs based on technical and macroeconomic analysis and utilized risk management techniques.

Cutler Group, LP, San Francisco, CA
Equity Options Market Maker / Options Analyst (July 2008 – September 2009)

- Acted as a NYSE Arca Options Market Maker for 80 equities, operating both on the floor of the Pacific Exchange and remotely on the Chicago Board Options Exchange (CBOE).
- Built a modified Black-Scholes model in Excel to evaluate discrete event outcomes, including FDA drug approvals, using fundamental and peer analysis; also modeled mergers and acquisitions arbitrage opportunities to assess market impact and pricing inefficiencies.
- Developed efficient, event-driven trading strategies by quantifying the short-term order flow impact of index rebalances on component stocks, resulting in profitable execution and improved market timing.

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, CHARLES MCCUTCHEN, 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: August 29, 2025

Charles McCutchen
CHARLES MCCUTCHEN

TIMOTHY POLLARD

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

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2025 Joint Energy Supply Plan Update
Docket No. 25-08___

Prepared Direct Testimony of

Timothy Pollard

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

A. My name is Tim Pollard. My position is the Director of Load Forecasting, Research and Analytics for NV Energy, Inc. ("NV Energy"), 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. During my current tenure with the Companies I have worked in the Rates and Regulatory Affairs department, where my primary focus has been on electric cost of service and rate design issues. I have been an expert witness before the Public Utilities Commission of Nevada ("Commission") regarding load forecasting, cost of service, regulatory pricing issues in support of the Rates and Regulatory Affairs department's responsibilities. I was also previously employed by the Companies in 2004 as a Load Forecasting Economist within the Resource Planning department.

My educational background, previous positions and professional experience are summarized in **Exhibit Pollard-Direct-1**.

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

A. My 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 regulatory 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 2025 Nevada Power General Rate Case (Docket No. 25-02016). 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 load forecast presented in Energy Supply Plan update ("2025 ESP Update forecast"), which incorporates updates to the load forecast approved in the 2024 Integrated Resource Plan ("IRP") (Docket No. 24-05014) in December 2024 by the Commission for the remaining two years of the action plan period, 2026 and 2027. Updates to the 2024 forecast include extending the date range during which the loads of Liberty Utilities remain as bundled service beyond December 2025 until May 2027, and updates to the large customer major project forecast components, which I discuss below.

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

A. I am sponsoring or co-sponsoring the following Exhibits:

Exhibit Pollard-Direct-1 Statement of Qualifications

Exhibit Pollard-Direct-2 Confidential – Major Project Summary

I am also sponsoring the Load Forecast Narrative and Load Forecast Technical Appendix ESP LF-1 (portions of which are confidential) provided with the filing. The original Load Forecast technical appendices (IRP LF-2 through IRP LF-8) from the 2024 IRP have not been updated as part of the 2025 ESP Update forecast.

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

A. Yes. **Exhibit Pollard-Direct-2** contains customer specific information regarding large customer projects incorporated into the 2025 ESP Update forecast. Further, certain workpapers provided with the filing supporting the inclusion of updates to the 2024 IRP approved forecast may include customer specific information and should also be considered confidential.

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

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

9. 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.

10. Q. PLEASE SUMMARIZE THE IMPACT OF THE UPDATES TO THE LOAD FORECAST.

A. For the remaining two-years of the ESP action plan period (2026 through 2027), the expected growth in annual retail energy for the Companies' combined system is forecasted to grow from 36,423 GWh in 2026 to 40,615 GWh in 2027, a Compound Annual Growth Rate ("CAGR") of 8.8 percent. The combined coincident Peak MW is forecasted to grow from 8,812 MW in 2026 to 9,231 MW in 2027, representing a CAGR of 1.1 percent over the two-year ESP action plan period.

Nevada Power's system is forecasted to grow from 24,108 GWh in 2026 to 25,922 GWh (an increase of 1,815 GWh), with a peak increase of 246 MW from the 2026 peak of 6,753 MW to 6,999 MW in 2027. This equates to a 6.2 percent CAGR in energy and 2.4 percent CAGR in Nevada Power's peak over the two-year ESP action plan period.

At Sierra, the expected growth in annual energy is forecasted to increase from 12,315 GWh to 14,693 GWh (an increase of 2,377 GWh), with a 248 MW increase from the 2026 peak of 2,279 MW to 2,527 MW in 2027. This growth equates to a 13.7 percent energy CAGR and 7.7 percent CAGR for Sierra's peak over the 2026 to 2027 period.

Table Pollard-Direct-1 summarizes the Annual Peak MW and GWh energy differences between the 2025 ESP Update forecast update to the forecast approved in the 2024 IRP filing.

TABLE POLLARD-DIRECT-1
ANNUAL PEAK (MW) AND RETAIL SALES (GWH) DIFFERENCES

		Peak (MW)		Energy (GWh)	
		2026	2027	2026	2027
Nevada Power	2025 ESP Update	6,753	6,999	24,108	25,922
	2024 IRP	6,608	6,674	22,875	23,161
	Difference	145	325	1,232	2,762
	Percent Difference	2.2%	4.9%	5.4%	11.9%
Sierra	2025 ESP Update	2,279	2,527	12,315	14,693
	2024 IRP	2,381	2,495	12,788	13,654
	Difference	(102)	32	(473)	1,038
	Percent Difference	-4.3%	1.3%	-3.7%	7.6%
NVE	2025 ESP Update	8,812	9,231	36,423	40,615
	2024 IRP	8,787	8,895	35,663	36,815
	Difference	25	336	759	3,800
	Percent Difference	0.3%	3.8%	2.1%	10.3%

11. Q. PLEASE SUMMARIZE THE IMPACT OF EXTENDING EXISTING SERVICE FOR LIBERTY UTILITIES UNTIL MAY 2027.

A. The retail service agreement for provision of energy service for Liberty Utilities is now being extended from December 2025 through May 2027. This extension increases Sierra's energy requirements in the 2025 ESP Update forecast more in the winter season as Liberty Utilities is a winter-peaking customer.

12. Q. PLEASE SUMMARIZE THE IMPACT OF UPDATING INFORMATION FOR LARGE CUSTOMER MAJOR PROJECTS IN THE 2025 ESP UPDATE FORECAST.

A. The Companies include recent information updates to the large customer major projects component for this 2025 ESP Update forecast. Customer specific summary information on each project is included in **Confidential Exhibit Pollard-Direct-2**, which summarizes the forecasted load growth over the remaining two years of the action plan for these projects. In total, the Companies included 292 MW of expected incremental load for all of these bundled projects in 2026 and 624 MW in 2027. While these large customer projects continue their increasing trend over recent years, in total, these projects show 94 MW lower loads in 2026 but 345 MW higher in 2027, relative to the approved 2024 IRP forecast, as these projects exhibit later ramp-up schedules.

Overall, there are 46 bundled service large customer projects included in this forecast update that represent 4,527 MW of customer requested peak capacity requirements through 2027. These projects are located primarily within the Tahoe-Reno Industrial Center area in Sierra's service territory and the Apex area at Nevada Power. In this 2025 ESP forecast update, 21 of the 46 bundled service projects have signed customer Rule 9 agreements requesting 1,500 MW of bundled-service capacity by 2027 at Sierra and 250 MW of capacity at Nevada Power by 2027. The remaining 25 projects are in the engineering study phase and have requested 2,777 MW of capacity, with 883 MW at Sierra and 1,894 MW at Nevada Power over the same period.

Consistent with past practice, these requests are scaled down in the retail load forecast. Historically approximately 40 percent of study phase projects move forward. The loads of bundled service projects in the study phase saw an average 2027 reduction of 87 percent, while the loads of bundled service projects with signed Rule 9 agreements were reduced by 46 percent.

13. 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

<u>Non-Sierra Employment</u>

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

<u>Education</u>
University of Nevada, Reno
Bachelor of Arts in Economics, August 2000

<u>Certifications</u>
SAS Certified Advanced Programmer
SAS Certified Basic Programmer

<u>Prior Testimony before Public Utilities Commissions</u>
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, 22-09006, 23-06007, 23-08015, 23-08019, 24-02026, 24-02027, 24-05022, 24-05041, and 25-02016.
CPUC Applications: 08-08-004.

EXHIBIT POLLARD-DIRECT-2

FILED UNDER CONFIDENTIAL SEAL

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: August 29, 2025

TIMOTHY POLLARD

LINDSEY SCHLEKEWAY

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

2025 Joint Energy Supply Plan Update
Docket No. 25-08___

Prepared Direct Testimony of

Lindsey Schlekeway

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

A. My name is Lindsey Schlekeway. My current position is the Market Policy Director, 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 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. I have a Bachelor of Science degree in Chemical Engineering from the University of Maryland. I have 12 years of experience in the electric utility industry mostly with the Companies. I have experience in market policy, transmission policy, and energy supply engineering. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Schlekeway-Direct-1**.

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

A. As the Market Policy Director, I represent the Companies as a stakeholder in the California Independent System Operator ("CAISO") stakeholder market policy process and other various regional market policy efforts. Additionally, I represent the Companies as a stakeholder in the Western Resource Adequacy Program ("WRAP") and lead the Companies' WRAP participation.

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

A. Yes. I previously filed testimony in the Companies' 2024 Joint Integrated Resource Plan, Docket No. 24-05041.

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

A. The purpose of my testimony is to provide support surrounding regional market efforts being undertaken by the Companies, such as participation in the WRAP and the development of a future day-ahead wholesale market.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibits:

Exhibit Schlekeway-Direct-1 Statement of Qualifications

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

A. The Federal Energy Regulatory Commission ("FERC") approved the WRAP tariff in February 2023. The Companies continue to participate in the transitional non-binding phase as an active member. However, the Companies have made the decision to withdraw from the WRAP due to inherent risks that outweigh the program's current benefits for both the Companies and their customers. While the Companies continue to recognize the value of regional collaboration in resource adequacy planning to ensure reliability across the West, there are five critical issues within WRAP's existing framework that significantly elevate risk exposure. These concerns must be addressed before the Companies can consider rejoining the program.

8. Q. WHAT IS THE FIRST CRITICAL ISSUE THAT THE COMPANIES HAVE IDENTIFIED WITHIN WRAP?

A. The first critical issue is the excessive deficiency charge penalty and the planning uncertainty. WRAP imposes steep penalties for capacity deficiencies identified seven months before the compliance season, based on the Cost of New Entry ("CONE") values or the cost to build a new gas generator. This penalty is applied without the added benefit of additional megawatts being added to the program to resolve the deficiency or to resolve the potential reliability issue. Utilizing the most recently available CONE value, Resource Optimization calculated that penalties could range from $16 to $22 million for a 100 MW deficiency if it occurred during every month for the summer season. This makes joining the program troublesome for load serving entities that are planning to catch up and meet increasing loads in an unprecedented time. Recently, the industry has been challenged with supply chain issues, tariffs, rapid load growth, etc. If a project is delayed and misses its commercial operational date, then the Companies would be required in the program to replace this capacity with supply that meets the program's requirements. If the Companies are not able to meet the supply requirements in time for the forward showing cure period, then the Companies would face the deficiency charges.

Further complicating program compliance is the volatility of the Planning Reserve Margin ("PRM"). Year-over-year changes have ranged from minor adjustments to swings as large as 10 percent. For a monthly peak load of 10,000 MW, this could translate to an unexpected need for 1,000 MW of additional capacity, which is an unrealistic burden to meet within such a short timeframe. This level of variability is too large to occur on such a short period, leaving little to no time for a participant to react and procure the additional supply. The Companies are pleased that the program is initiating the process to potentially revise the policy and address this issue beginning in July 2025. However, the resolution of this issue will likely occur after the deadline, October 31, 2025, to withdraw from the program in order to not become a binding participant. The combination of the high deficiency charges and the volatile PRM requirements creates high financial risk and planning challenges, especially amid supply chain disruptions and rapid load growth.

9. Q. WHAT IS THE SECOND CRITICAL ISSUE THAT THE COMPANIES HAVE IDENTIFIED WITH WRAP?

A. The second critical issue is the governance structure following the recent approval of the Markets+ tariff, which requires all load serving entities within that market to be a WRAP participant. While expanding participation can enhance regional reliability, it may disadvantage entities that prefer to remain in the Western Energy

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d/b/a NV Energy

Imbalance Market ("WEIM") or transition to the Extended Day-Ahead Market ("EDAM"). It is expected that each year new participants will join the WRAP as Markets+ moves through implementation adding in new balancing authority areas. Any third-party load serving entities that are in a balancing authority area that joins Markets+ will also be required to join WRAP. This will add additional members that are not currently participating in the program along with additional load, increasing the number of voting members that participate in a specific market.

In the Resource Adequacy Participant Committee each member gains a vote utilizing a house and senate model to vote on program changes that if approved will move to the Board. The house vote uses the participants median monthly P50 peak load while the senate vote uses a non-weighted single vote for each member.[1] As this new market moves through implementation it is not unreasonable to assume that the participants within that market may need to propose and implement changes to accommodate Markets+ since WRAP participation is mandatory for those members. It is unknown if such changes would or would not harm the members that are remaining in the WEIM or leaning towards EDAM, but it is possible, considering the participants in this minority group will likely lose their veto power with new member additions. Essentially, the WRAP voting model may dilute the influence of non-Markets+ participants leading to potential harm prior to the ability for the participant to exit the program, which occurs two years following a notification. The WEIM and EDAM WRAP members may lose their veto power with the addition of participants that participate in Markets+.

[1] Western Power Pool. (2025). Western Resource Adequacy Program (WRAP) Tariff. Effective March 16, 2025. Retrieved from Western Power Pool website.

10. Q. WHAT IS THE THIRD CRITICAL ISSUE THAT THE COMPANIES HAVE IDENTIFIED WITH WRAP?

A. The third critical program issue is the lack of market oversight and procurement mechanisms. WRAP lacks a formal capacity market and market monitor, despite imposing mandatory participation through Markets+ and the creation of a new market product in the West. Strict procurement rules and high penalties create a risk of inflated prices and limited access to compliant supply, with no oversight to prevent market manipulation.

WRAP was originally approved as a voluntary program. However, the mandatory WRAP participation requirement ensures that all Markets+ participants meet the forward showing supply requirements or pay the deficiency charges for each winter and summer season. Since not all participants may have enough supply to meet the resource adequacy requirements, they will likely need to purchase this supply ahead of the forward showing season. WRAP has specific and strict guidelines for purchasing additional supply in which both the seller and buyer must attest that both parties have met the requirements in order for the supply to count towards the forward showing. 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 attestation affirming the capacity being utilized will not be committed to other needs. These requirements are above the commonly used WSPP Inc.'s ("WSPP") Schedule C contract which includes financial penalties if the supplier fails to deliver. Since the program is a requirement to participate in a market, this has created a new issue that load serving entities will be required to procure WRAP compliant supply if they cannot meet the requirements on their own. This extends this issue to others that are short within the region and need to purchase WRAP compliant supply due to the competition to receive a product for a program that has very high penalties if no such product can be found. Most of the resources in the Western Energy Coordinating Council ("WECC") region are associated with vertically integrated utilities that must ensure supply to their native load before engaging in bilateral sales. Thus, there is an extremely limited number of suppliers that have both seven-month ahead capacity availability and associated firm transmission rights. WRAP was designed to be a voluntary program, therefore, no market monitoring department was created to oversee the program. Markets+ simply added the program as a requirement in its tariff. Meaning that the market monitor that has authority over the Markets+ tariff will not have authority over WRAP. This lack of oversight leads to the possibility of suppliers taking advantage and offering supply at or near the deficiency charge penalties. This would significantly disadvantage customers in the west from receiving competitive supply that satisfies the forward showing requirements.

11. Q. WHAT IS THE FOURTH CRITICAL ISSUE THAT THE COMPANIES HAVE IDENTIFIED WITH WRAP?

A. The fourth critical issue is the underutilization of transmission and the resulting lack of a diversity benefit. WRAP models the participants in two separate sub regions with limited transmission connectivity between them. This modeling approach does not consider a large amount of the transmission that has been proven to be utilized and available through the WEIM. It is notable that the program has strict firm transmission requirements, and that the Available Transfer Capability ("ATC") determined in real-time is not firm enough to qualify under the program rules. However, there has been significantly more transmission capability that has occurred through market participation than the 500 MW assumed by the program. Therefore, it is the Companies' perspective that the program undervalues this transmission capability which eliminates any major diversity benefit from occurring in the forward showing resulting in higher PRMs. The program should not artificially set the transmission requirement on a definition of Open Access Transmission Tariff ("OATT") firm transmission; but instead, should perform historical studies to determine what transmission has been available seasonally.

12. Q. WHAT IS THE FIFTH CRITICAL ISSUE THAT THE COMPANIES HAVE IDENTIFIED WITH WRAP?

A. The fifth critical issue is the uncertainty around operational holdback availability. The operational holdback mechanism is untested and may not function effectively during widespread events like heatwaves. WRAP is untested because the program has yet to establish a binding season. The Companies question whether or not holdback will be available if a heat wave occurs and Nevada needs to call on the program for supply. The concept of holding back capacity for program participants has been the valuable proposition for the program because program members agree to supply surplus to another participant when deficient. However, the program models the participants at two subregions separating the southwest from the northwest participants and does not perform sharing amongst the two subregions in the operational program. This is not advantageous when weather events in the recent past have occurred over large areas of the desert southwest that have benefitted from connectivity to available supply from the northwest.

Additionally, the program only measures surplus capacity up to the forward showing requirement minus an uncertainty factor. Meaning that any capacity that

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is available above each individual forward showing requirement is not considered for the sharing calculation and should be thought of as supply that is out of the program. Considering the lack of sharing between the two subregions and the lack of additional supply above the forward showing requirement minus uncertainty, it is reasonable to assume that the operational programs concept of holdback may not be available in the southwest in the event of a large heatwave.

13. Q. WHAT ARE THE COMPANIES' NEXT STEPS FOR WRAP?

A. The Companies will send a letter to the Western Power Pool stating their request to withdraw from WRAP. The Companies will continue to monitor the program's development and remain open to future participation should WRAP evolve to address these five critical issues. Until then, the Companies will pursue alternative avenues to ensure regional reliability and resource adequacy for their customers.

14. 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 EDAM in October 2025. As the second participant in the 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 hopes 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, Public Service Company of New Mexico, Imperial Irrigation District, Turlock Irrigation District, PowerWatch 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.

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

A. Yes.

EXHIBIT SCHLEKEWAY-DIRECT-1

STATEMENT OF QUALIFICATIONS

LINDSEY E SCHLEKEWAY

NEVADA POWER COMPANY d/b/a NV Energy
SIERRA PACIFIC POWER COMPANIES d/b/a NV Energy

NV Energy
6226 West Sahara Avenue
Las Vegas, NV 89146

PROFESSIONAL EXPERIENCE

NV Energy: February 2022 to Present
Market Policy Director
Market Policy Manager

- Evaluates proposed market rules and market design changes that impact commercial operations and transmission tariffs, including but not limited to a Day Ahead Market, Energy Imbalance Market ("EIM"), any potential organized market expansions, the Western Resource Adequacy Program ("WRAP"), and the Companies interaction with market participants outside of organized markets.
- Advocates for policy changes within the market or resource adequacy program. This may include presenting alternative proposals on behalf of the Companies.
- Leads the Companies participation within WRAP.

PacifiCorp: November 2019 – February 2022
Transmission Policy Specialist

- Managed the PacifiCorp filing to update Transmission Customer rates and self-supply provisions for the Ancillary Service Rate Case Filing.
- Oversaw PacifiCorp's participation in the California Independent System Operator (CAISO) stakeholder process for Transmission and any overarching market design changes
- Member of the Oregon RTO Advisory Committee in response to SB 589
- Led PacifiCorp's initial stakeholder engagement in CAISO's Extended Day Ahead Market

NV Energy: November 2014 - November 2019
Program Manager – Wholesale Market, NV Energy, Resource Optimization
Sr. Merchant Market Specialist
Merchant Market Specialist
Merchant Market Analyst

- Led the participation in the CAISO stakeholder process
- Negotiated and proposed market designs with other market stakeholders and CAISO
- Developed NV Energy's comments for the CAISO stakeholder process
- Monitored all CAISO stakeholder activities, market participant filings, and market related regulatory changes including FERC filings and NOPRs for Resource Optimization
- Assisted Resource Optimization's Trading and Operations groups
    - Identifies market issues
    - Provides recommendations for business or process solutions
- Managed the participating resource Masterfile update process
- Led the CAISO market initiative releases that impact Resource Optimization
    - Discusses the potential impacts of new market releases with management
    - Creates training material and provides training when needed
    - Directs market enhancements testing in a simulation environment
    - Works closely with the software vendor to ensure a smooth operation transition into production
- Developed ambient derate tables for Resource Optimization to determine each resources capacity for the EIM from forecasted and current ambient conditions
- Devised and implemented testing procedures, logs, and scripts to test each resources capability and availability to the EIM
- Built a resource data template for all the participating resources for the EIM
- Created a 2015 forecast for Goodsprings for Resource Optimization to establish a resource plan

<u>Southwest Gas Corporation: August 2014 – November 2014</u>
Engineer I

- Designed gas facilities to include but not limited to mains, services, regulator stations, meters and anode beds
- Provided cost estimates and technical support for the projects

<u>JEA Public Utility: February 2012 – April 2014</u>
Plant Engineer

- Engineer responsible for all changes made to any water treatment and chemical processes in the plant
- Led a study for the industrial waste water treatment system to reduce scaling which included a pilot test and resulted in a new chemical treatment method for the plant.

- This project included: research, bench tests, conceptual design: pump selection, pipe routing, PLC design, engineering work package, training operations, data collection, report

EDUCATION

Bachelor of Science in Chemical Engineering,
University of Maryland, College Park, 2010

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, LINDSEY SCHLEKEWAY, 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: August 29, 2025

LINDSEY SCHLEKEWAY

SEAN SPITZER

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

2025 Joint Energy Supply Plan Update
Docket No. 25-08___

Prepared Direct Testimony of

Sean Spitzer

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

A. My name is Sean Spitzer. I am the Director of Renewable Energy and Origination for Sierra Pacific Power Company d/b/a NV Energy ("Sierra") and Nevada Power Company d/b/a NV Energy ("Nevada Power" and, together with Sierra, the "Companies"). My business address is 7155 S. Lindell Road in Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

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

A. I graduated from California State University, Chico, with a Masters in Environmental Science in 2011 and a Bachelor of Science in Environmental Studies from University of California, Santa Barbara, in 2006. I have more than a decade of experience in the energy industry. Before joining the Companies, I worked for General Electric (GE Hitachi Nuclear Energy), and Clean Harbors Environmental Services. In my current role, I serve as the Director of Renewable Energy and Origination.

My responsibilities include the procurement and contract negotiations for renewable and non-renewable energy resources, building a clean energy project portfolio and ensuring new opportunities align with policy goals.

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

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

A. I lead and collaborate with a team responsible for long term energy and capacity procurement for the Companies. This includes planning and executing competitive solicitations for new energy resources, evaluating proposals, negotiating power purchase agreements ("PPAs") or build-transfer agreements, and coordinating internally with planners, engineers, and analysts to integrate new resources into the Companies' portfolio. I am also involved in ensuring that our resource procurement strategy aligns with Nevada's Renewable Portfolio Standard ("RPS") compliance and the Companies' goal of achieving carbon reduction targets.

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

A. Yes. Most recently, I provided written testimony in the 2024 Energy Supply Plan filed in the Companies' 2024 Joint Integrated Resource Plan ("IRP"), Docket No. 24-05041.

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

A. The purpose of my testimony is to sponsor Section 2.D of the Companies' 2025 Joint Energy Supply Plan Update ("ESP Update"). Specifically, I explain and support the Companies' plan for complying with Nevada's RPS.

6. Q. PLEASE DESCRIBE NEVADA'S RPS.

A. Nevada utilizes a portfolio energy credit ("PC") system to measure RPS compliance. Eligible PCs can come from multiple sources. The most common source of PCs are from renewable generation owned by the Companies or under PPAs, non-current year renewable generation banked PCs, eligible station usage PCs and grandfathered solar multiplier PCs.

Nevada's RPS requirement for calendar year 2025 (and continuing through 2026) is set at 34 percent of retail sales.[1] This means that Nevada Power and Sierra must have PCs equal to or greater than 34 percent of their respective retail sales. The RPS steps up to 42 percent in 2027 through 2029, and 50 percent in 2030 and thereafter.[2]

The state also has an aspirational goal for energy production from net-zero carbon dioxide emission resources equal to the total amount of electricity sales by 2050.[3]

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[1] Nevada Revised Statutes ("NRS") § 704.7821.
[2] *Id.*
[3] *See* NRS § 704.7820.

7. Q. HOW HAS THE TREATMENT OF ENERGY EFFICIENCY IN RPS COMPLIANCE CHANGED IN 2025?

A. Under prior law, utilities were allowed to count energy efficiency savings as a limited portion of RPS compliance. From 2020 through 2024, up to 10 percent of the annual RPS requirement could be met with credits from qualifying energy efficiency measures (with at least half of those savings coming from residential customers). As of January 1, 2025, however, energy efficiency and demand response program PCs are no longer permitted. The Companies have accounted for this change and have factored it into the 2025 ESP Update.

8. Q. PLEASE DESCRIBE THE RPS RENEWABLE PLAN DEVELOPED FOR THE ESP.

A. The Companies use a model to forecast future PC requirements and PC supplies. The purpose of the model is to determine whether the Companies will have sufficient PCs to meet their RPS obligations. In this filing, the Companies are providing estimates through the ESP action plan period 2025-2027.

Please refer to the Renewable Energy Planning section in the Companies' 2025 ESP Update filing for additional details regarding key inputs and assumptions to the model.

9. Q. PLEASE EXPLAIN THE ASSUMPTIONS AND METHODOLOGY UNDERLYING THE MODIFIED SHORT-TERM RENEWABLE EXPANSION PLAN.

A. The renewable expansion plan developed for short-term planning purposes captures actual historical generation trends based on two or more years of operating data. After coordinating with internal contract administrators, the Companies adjusted the supply table based on this historical trend to reflect the most recent operating data to account for potential short-term anomalies. Historical output trends for Sierra contracted renewable projects resulted in an adjustment to seven projects, three decreases and four increases. In total, these adjustments lowered the amount of renewable energy by an average of 0.66 percent over the 2025-2027 ESP action plan period.

The same approach for Nevada Power resulted in adjustments to the amount of renewable energy for 13 projects, 12 decreases and one increase. In total, these adjustments lowered the amount of renewable and derived credits by an average 2.37 percent over the 2025-2027 action plan period. The Companies believe that this approach maximizes the reliability and accuracy for the overall energy supply used in short-term planning.

10. Q. PLEASE DESCRIBE NEVADA POWER'S ESP RPS OUTLOOK AND ANY POTENTIAL CONCERNS.

A. Nevada Power exceeded the 2024 RPS requirement of 34 percent. Nevada Power's RPS compliance outlook is projected to be compliant in the 2025 and 2026 years, however, non-compliant starting in the year 2027. The limited available private land for development, multiyear project permitting timelines, and lack of available transmission capacity are key constraints in the renewable project pipeline. The completion of costly requisite network upgrades, procurement of long-lead critical equipment such as breakers and transformers, as well as project permit issuance and transmission interconnectivity capability, are interdependent project milestones that are subject to various independent external forces that cannot be easily mitigated even with diligent planning. Nevada Power's renewable project pipeline therefore carries some amount of inherent risk. To this end, Nevada Power will continue to explore all options so that it can procure the renewable generating and storage resources needed to continue its commitment to becoming carbon-free. Nevada Power's challenge is to make certain that it has sufficient renewable resources, existing and pipeline, to satisfy all PC and energy needs for the years through 2027 and beyond.

11. Q. PLEASE DESCRIBE SIERRA'S RPS OUTLOOK AND ANY POTENTIAL CONCERNS.

A. Sierra exceeded the 2024 RPS requirement of 34 percent. Sierra is forecasted to be compliant in the 2026 year, however, it is projected to be non-compliant starting in the year 2027. This is different from the 2024 IRP's outlook of uncertain for several reasons. First, and primarily, is projected load growth. Sierra's current retail load outlook in the 2024 IRP is significantly higher than that of the previous approved plan. Under the load forecast included in the 2025 ESP update, while Nevada Power's retail sales are projected to increase slightly, Sierra's retail sales are projected to increase significantly. Because the RPS credit requirement is tied directly to retail sales, this dramatically increased Sierra's forecasted RPS credit requirement.[4]

The second reason for Sierra's uncertain compliance outlook is cancelled or delayed projects by developers.[5] While Nevada Power was hit by the same wave of canceled projects, it did not face the same degree of projected sales growth. While every project is entered into with the expectation of success, events can and do happen that make once-viable projects unviable.

A third contributing factor to Sierra's uncertain RPS compliance outlook is transmission constraints. Currently there is limited ability to move power from generation to load in Sierra' service territory in the near term, requiring completion of contingent facilities and significant additional transmission infrastructure to remedy. The completion of Greenlink West and Greenlink North will allow for a significant addition of renewable energy capacity in Sierra's territory when it goes into service.[6]

The fourth contributing factor to Sierra's non-compliance are the Sierra Utility Owned Community Solar and Solar For All projects proposed in Docket No. 24-05041 that were not approved, resulting in the loss of a planned 6,312 PCs. It is the combination of these four factors that

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[4] Please refer to the Renewable Energy Planning section in the Company's 2025 ESP filing for additional details

[5] Please refer to the Renewable Energy Planning section in the Company's 2025 ESP filing for additional details on the cancelled and delayed projects.

[6] Please refer to the Renewable Energy Planning section in the Company's 2025 ESP filing for additional details

changed Sierra's outlook from uncertain to forecasted non-compliance in 2027 and beyond.

In summary, Sierra is projected to be non-compliant in 2027.

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

A. Yes.

EXHIBIT SPITZER-DIRECT-1

STATEMENT OF QUALIFICATIONS

Sean Spitzer | 7155 Lindell Rd. Las Vegas, NV 89118 | (702) 402-3107
sean.spitzer@nvenergy.com

Professional with over 14 years of experience in the power industry. Recent focus on renewable energy origination activities.

EXPERIENCE

NV Energy, Las Vegas, NV
Director, Renewable Energy & Origination | 2024-Present

- Lead renewable energy procurements through competitive solicitations and bilateral opportunities, ensuring resources are cost-effective, reliable, and compliant with regulatory requirements.
- Oversee renewable energy contract negotiations to secure favorable terms that maximize customer value while maintaining project viability.
- Direct origination activities that support the Integrated Resource Plan and align procurement decisions with the company's long-term energy supply portfolio strategy.
- Provide executive leadership with analysis of market trends, risks, and opportunities to inform prudent decision-making.

Sr. Project Manager, Renewables & Origination | 2023-2024

- Procure renewable energy contracts via RFP and bilateral proposal due diligence project evaluations. Facilitate subject matter experts in completing technical analyses and utilize financial models to determine project financial viability.
- Guide renewable energy contract negotiations for enhanced value and minimal risk.
- Support Integrated Resource Plan and General Rate Case filings as key contributor for Renewables.

Environmental Services Supervisor | 2022-2023

- Managed air quality-related environmental compliance for all business operations.
- Led multidisciplinary team to secure gas and coal power plant Title V operating permits.

Sr. Environmental Advisor | 2016-2022

- Performed project impact evaluations and delivered key information to stakeholders.
- Supported environmental compliance programs to ensure regulatory integrity.

GE (General Electric Company); GE Hitachi Nuclear Energy, Sunol, CA
EHS Specialist | 2012-2016

- Executed compliance programs pertaining to air, water, waste, and industrial safety at a nuclear facility.

NV Energy, Las Vegas, NV
Environmental Engineer | 2011-2012

- Quality-assured CEMS emissions data for combined-cycle power plants; managed reporting.

Clean Harbors Environmental Services, West Sacramento, CA
Sr. Lead Chemist | 2007-2008

- Team leader for multi-day hazardous waste packaging & environmental clean-up projects.

EDUCATION

California State University, Chico
Masters of Science in Environmental Science | 2011

University of California, Santa Barbara
Bachelor of Science in Environmental Studies | 2006

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, SEAN SPITZER, 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: August 29, 2025

SEAN SPITZER

MATTHEW VALENTIC

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

2025 Joint Energy Supply Plan Update
Docket No. 25-08___

Prepared Direct Testimony of

Matthew Valentic

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

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

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

A. I graduated from the University of Nevada, Reno with a bachelor's degree in mathematics and obtained master's degrees in accountancy and business administration. I have been employed by the Companies since 2017, with most of my time spent in the Revenue Accounting department, of which my duties included the preparation of Statement J for both Nevada Power and Sierra, Exhibit G in support of the quarterly Deferred Energy Accounting Adjustment ("DEAA") filings, and other projects. **Exhibit Valentic-Direct-1** contains additional information regarding my qualifications.

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

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

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

A. Yes. I have previously testified before the Commission in several dockets, which are listed in **Exhibit Valentic-Direct-1**. Most recently, I filed testimony in Nevada Power's General Rate Case, Docket No. 25-02016.

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

A. The purpose of my testimony is to provide background information about the forecasted Base Tariff Energy Rate ("BTER") and Deferred Energy Accounting Adjustment ("DEAA") components and how they were developed for the gas hedging plan for the 2026 - 2027 action plan period.

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

A. I sponsor the following exhibits and appendices:

Exhibit Valentic-Direct-1	Statement of Qualifications
Technical Appendix GAS-2	Summary of Actual and Forecasted BTERs and DEAA

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

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

7. Q. DID YOU PREPARE THE FORECASATED BTER AND DEAA?

A. Yes. The forecasted BTERs and DEAAs, assuming base, low, and high fuel and purchased power costs, for the gas hedging plan were prepared under my direction. As discussed in this filing, the Companies are not proposing any gas hedges.

8. Q. HOW WERE THE FORECASTED BTERS AND DEAAS CALCULATED?

A. Base, low, and high fuel and purchased power price forecasts for 2026 - 2027 were prepared by the Resource Planning team, as sponsored by Zeljko Vukanovic and are presented in Technical Appendix FPP-1. These forecasts were used in the PLEXOS[1] model to estimate the total cost to serve. The estimates generated by PLEXOS, which are also sponsored by Mr. Vukanovic, were used to forecast BTERs and DEAAs for 2026 - 2027 under base, low, and high price scenarios. A summary of the actual and forecasted BTERs and DEAAs is provided in Technical Appendix GAS-2, pages 1 and 3 for Nevada Power and Sierra, respectively.

9. Q. PLEASE SUMMARIZE THE POTENTIAL RANGE OF RATE IMPACTS OF THE GAS HEDGING PLAN.

A. Figures Valentic-Direct-1 and Valentic-Direct-2 reflect the combined Nevada Power 2026 - 2027 forecasted residential and non-residential BTERs and DEAAs for the plan.

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[1] Refer to testimony of Company witness Zeljko Vukanovic for further explanation of PLEXOS modeling.

Figure Valentic-Direct-1

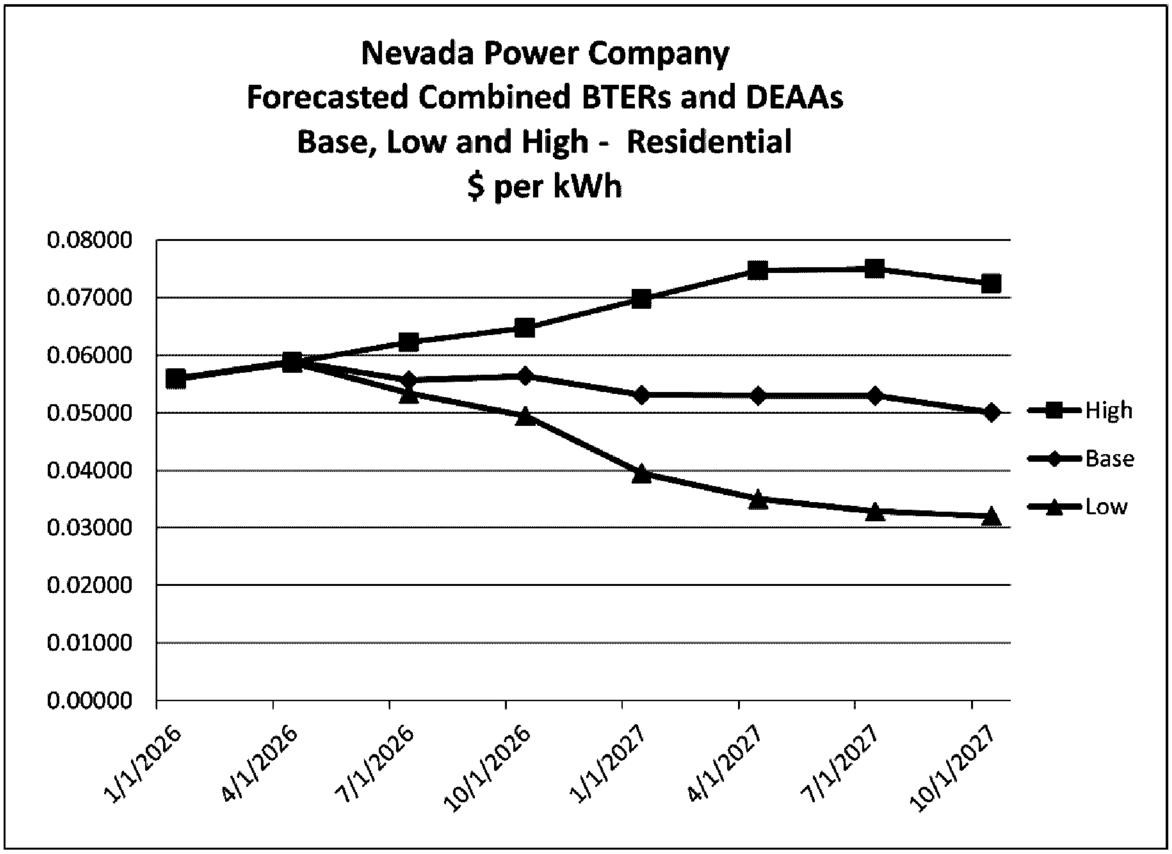


Figure Valentic-Direct-2

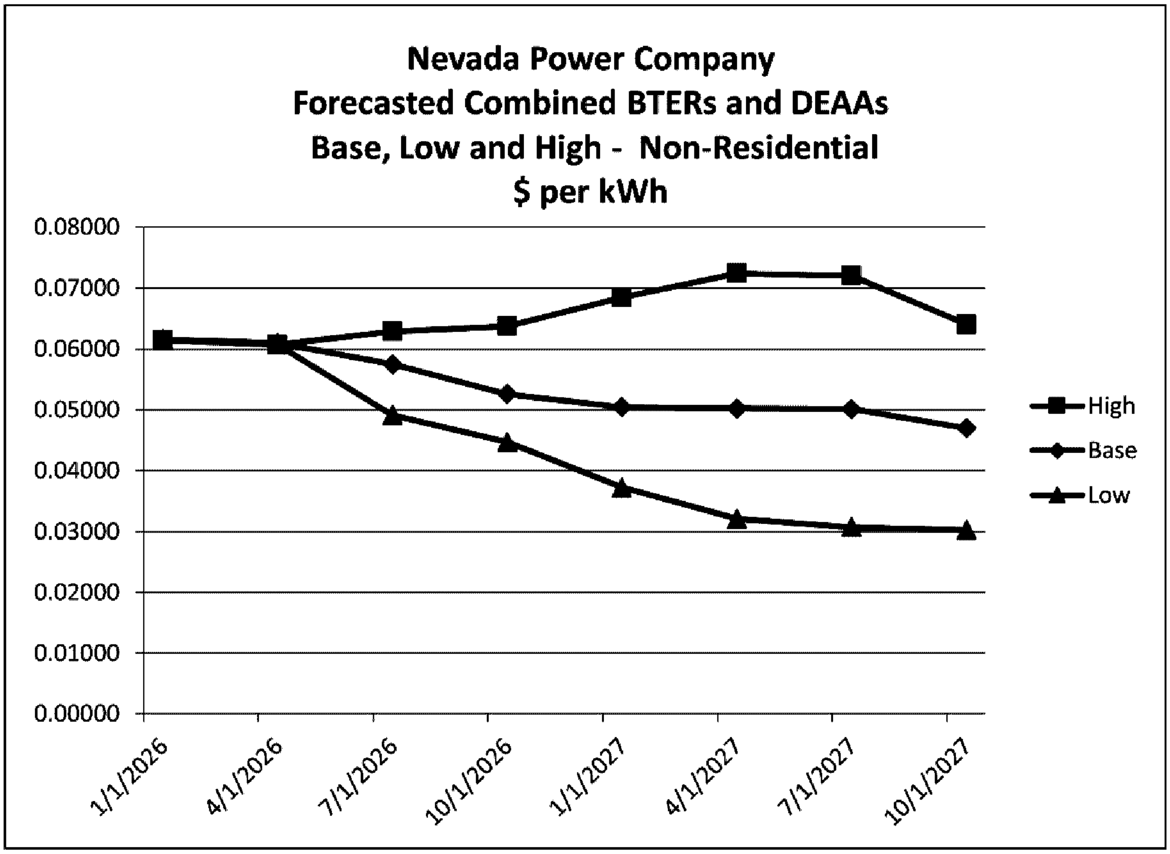
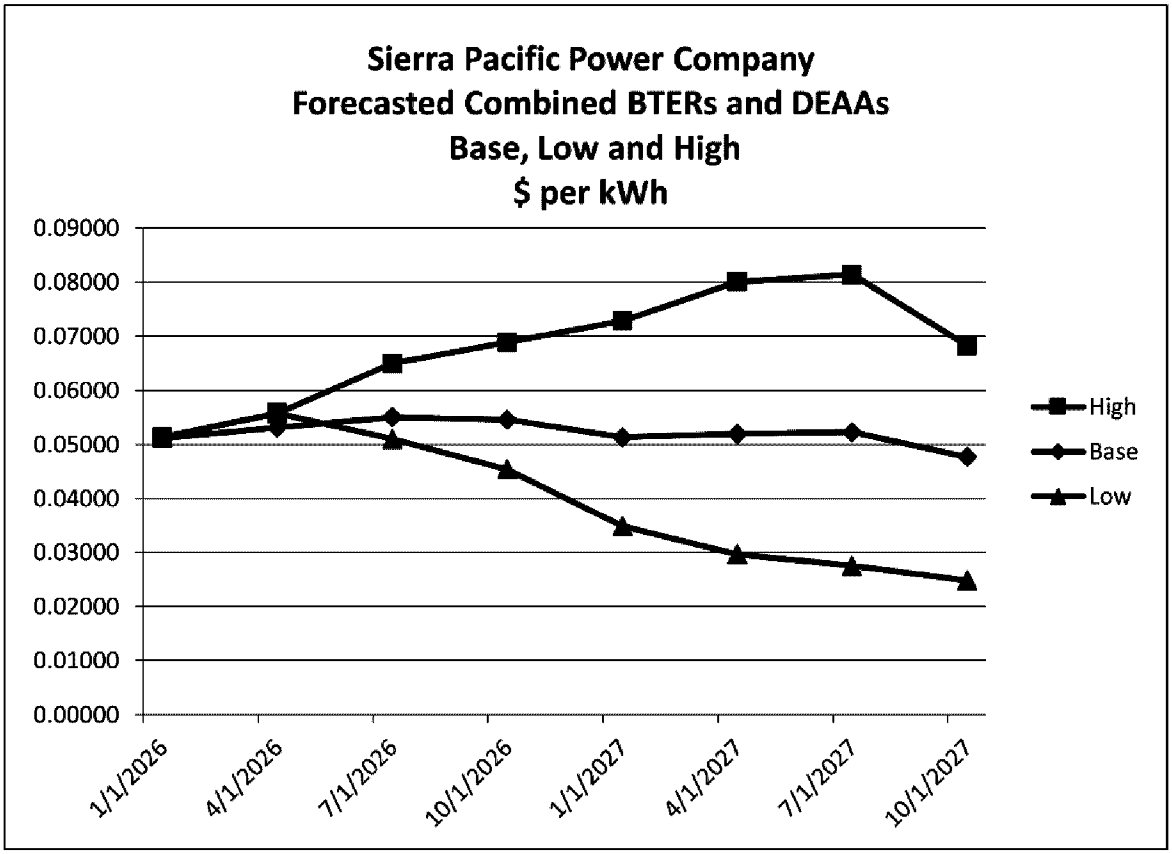


Figure Valentic-Direct-3 shows the combined 2026-2027 forecasted Sierra BTERs and DEAAs for the plan.

Figure Valentic-Direct-3



10. Q. WERE CARRYING CHARGES CALCULATED FOR THE GAS HEDGING PLAN?

A. Yes. The estimated carrying charges are provided in Technical Appendix GAS-2, pages 2 and 4 for Nevada Power and Sierra respectively.

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

A. Yes.

EXHIBIT VALENTIC-DIRECT-1

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

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

EMPLOYMENT HISTORY

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

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

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

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

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

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

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

<u>EDUCATION</u>

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

<u>Prior Testimony Before the Public Utilities Commission of Nevada</u>

22-06014	23-06007	24-02026	24-02027	25-02016	25-02033
25-02034	25-02035				

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

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

Date: August 29, 2025

MATTHEW VALENTIC

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

2025 Joint Energy Supply Plan Update
Docket No. 25-08___

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"). 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 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 most recently in Docket Nos. 24-05041, 25-02033, 25-02034, and 25-02035.

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

A. In my testimony, I sponsor the following sections in the Companies' Energy Supply Plan Update ("ESP Update"), which covers the years 2026 and 2027.

- Section 5.B ("Gas Transportation Plan")

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

A. Section 5.B of the ESP Update captures in more detail the Companies' gas transportation portfolios. The Companies are proposing to maintain their current transportation portfolios during the Action Plan Period. Section 2.E of the narrative, sponsored by the Companies' witness Charles McCutchen, discusses the analysis which informs the gas transportation requirements. Since Nevada Power's firm transportation rights are lower than the projected volume of natural gas flowing to Southern Nevada during the summer months, and Sierra's firm transportation rights during the winter months are at the projected volume of natural gas flowing to Northern Nevada for Sierra's generation and local distribution company ("LDC"), the Companies feel it is prudent to, at a minimum, maintain their existing transportation portfolios.

7. Q. IS THERE A CONCERN FOR SUFFICIENT GAS TRANSPORTATION CAPACITY IN THE FUTURE BEYOND THE ACTION PERIOD FOR NEVADA POWER AND SIERRA, AND HAVE THE COMPANIES CONSIDERED ADDING TO THE GAS TRANSPORTATION PORTFOLIO?

A. Yes. It should be noted that the pipelines currently utilized by the Companies to meet their needs are fully subscribed. That is, there is no additional transportation capacity available for the Companies to obtain. Therefore, the Companies have begun looking at the possibility of gas transportation expansions.

Historically, Nevada Power has been able to meet its transportation shortage through firm delivered gas - gas that includes transportation with the commodity.

To date, this market has proven to provide adequate liquidity needed to meet the generation requirement of Nevada Power. The plan for Nevada Power is to continue to procure firm delivered gas when needed while monitoring the liquidity of delivered gas.

Sierra is in a different position. Delivered gas is not a liquid commodity on the Tuscarora and Great Basin pipelines serving Sierra because the number of shippers and off takers of gas on these pipelines is small. Therefore, there is more of a need for a gas transportation expansion by the upstream pipelines for Sierra. The Companies are in the process of preparing an integrated resource plan to be filed in 2025, which will inform Sierra of any additional gas transportation needs for the future. Based on this analysis, the Companies may bring forward a gas transportation expansion plan in that filing or a future filing.

It should be noted that Sierra will soon be adding to its transportation portfolio for the conversion of the Valmy coal units to natural gas. Sierra will be adding transportation capacity from Ruby Pipeline and Pinyon Pipeline to supply natural gas to the Valmy natural gas conversion units. Sierra will execute transportation service agreements prior to the commercial operation date of the first Valmy gas conversion unit, which is expected by January 1, 2026. These pipelines will also serve two combustion turbines at the Valmy site which were approved by the Commission in Docket No. 24-05041 and are expected to become operational in 2028. However, due to the geography of the Valmy plant and these pipelines, this additional transport capacity does not increase the capacity on Tuscarora or Great Basin to serve Sierra's non-Valmy generation and LDC needs.

8. Q. IN REGARD TO INTERSTATE PIPELINE RATE CASES, HAVE ANY INTERSTATE PIPELINE RATE CASES CONCLUDED OR INITIATED SINCE THE LAST ESP?

A. The rate case filed by Gas Transmission Northwest Pipeline at FERC on September 29, 2023, was settled in July of 2024.

The rate case filed at FERC by Great Basin Gas Transmission on March 6, 2024, was settled in November 2024.

9. 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: August 29, 2025

VINCENT VITIELLO

ZELJKO VUKANOVIC

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

2025 Joint Energy Supply Plan Update
Docket No. 25-08___

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"). 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 EDUCATIONAL AND PROFESSIONAL BACKGROUND AND EXPERIENCE.

A. I hold a Masters of Science in Finance and Banking from Boston University and Masters in Business Administration from 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 a Valuation Specialist, where I performed Energy Supply Plan analyses. I have also held the Consultant Staff position in the Demand Side Management department at the Companies. 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, 22-11032, 23-08015 and 24-05041.

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

A. I sponsor the following sections in the Companies' 2025 Joint Energy Supply Plan Update for 2026-2027 ("2025 ESP Update"):

- Section 3.A. ("Market Fundamentals") co-sponsor with Lindsey Schlekeway
- Section 3.B. ("Fuel and Purchased Power Price Forecasts")

I also sponsor Technical Appendix FPP-1, the fuel and purchased power price forecasts.

5. Q. PLEASE BRIEFLY DESCRIBE THE NATURAL GAS AND PURCHASED POWER PRICE FORECASTS USED IN THE ESP.

A. The ESP base power and natural gas price forecasts were developed using a 21-day average of market-based price quotes from May 2025. These quotes reflect observed transactions at the following natural gas trading hubs: Henry Hub, Alberta NOVA Inventory Transfer ("AECO"), Sumas, Northwest Pipeline Rockies ("Rockies"), Malin, and the Southern California Border ("SoCal"). Similarly, quotes for purchased power are obtained from Argus

Media and reflect observed transactions at power trading hubs Mead and Palo Verde.

6. Q. PLEASE BRIEFLY DESCRIBE THE PROCESS USED TO PREPARE THE HIGH AND LOW PRICE FORECASTS USED BY THE COMPANIES IN THE ESP.

A. The Companies include sensitivity analyses around the base case projections in order to determine how the total fuel and purchased power costs could vary under two extreme 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). The development of the high and low power price curves involves taking the respective high and low natural gas price forecast and multiplying it with the heat rates from the market-based price quotes. The final high and low power price curves are produced by adding the spark spread value[1] that was calculated in the base case power price forecast.

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

A. Wood Mackenzie's ("WoodMac") regional power price forecast represents day-ahead firm energy prices; it does not explicitly include the full cost of new capacity additions that would be required to ensure resource adequacy over the forecast period. 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-month) is multiplied by the

[1] The spark spread is the difference between the price received by a generator for electricity produced and the cost of the natural gas used to produce that electricity; it is also an estimation of the value of energy in wholesale markets, reflective of the comparative balance between power supplies and electricity demand.

Companies' open capacity position, if not filled by external power contract placeholders, as an additional fixed fuel and purchased power cost.

8. Q. WHAT IS THE SOURCE OF THE COMPANIES' LONG-TERM CAPACITY PRICE FORECAST?

A. The Companies have utilized WoodMac's capacity price forecast in the preparation of the ESP Update for 2026-2027. As part of its Long-Term Outlook, WoodMac prepared an estimate of the levelized cost of new entry ("CONE") for the installed cost of future combined cycle and combustion turbine 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). WoodMac then calculates the capacity price forecast (in dollars per kW-year) as the difference between the CONE and the net energy and ancillary services margins reflected in the wholesale power price forecast.

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

A. Yes. FPP-1 is being filed confidentially. This confidential information is commercially sensitive and/or trade secret information that derives independent economic value from not being generally known. 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 and their customers by limiting the ability to foster competition among prospective suppliers, compromising the Companies' negotiating position and reducing their bargaining leverage. Publication of this information would impair the Companies' ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of its customers.

10. Q. FOR HOW LONG DO THE COMPANIES REQUEST CONFIDENTIAL TREATMENT?

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

11. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF REGLATORY OPERATIONS STAFF ("STAFF") OR THE BUREAU OF CONSUMER PROTECTION ("BCP") TO FULLY INVESTIGATE THE ESP?

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

12. Q. DOES THIS CONCLUDE YOUR PREPARED 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

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: August 29, 2025

ZELJKO VUKANOVIC

NARRATIVE

NEVADA POWER COMPANY d/b/a NV ENERGY
SIERRA PACIFIC POWER COMPANY d/b/a NV ENERGY
JOINT ENERGY SUPPLY PLAN UPDATE FOR 2026-2027

TABLE OF CONTENTS

SECTION 1 - EXECUTIVE SUMMARY

A. INTRODUCTION

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") respectfully submit this joint Energy Supply Plan Update for 2026-2027 ("ESP Update"). In accordance with Nevada Administrative Code ("NAC") §§ 704.9506 and 704.9482, this ESP Update sets forth the Companies' power procurement plan, fuel procurement plan, and risk management strategy for calendar years 2026-2027. NRS § 704.9508 requires that this ESP Update be processed within 120 days of filing. The Companies request that the Public Utilities Commission of Nevada ("Commission") approve this ESP Update and make the determinations of prudence provided for in NAC § 704.9494 regarding each element of the plan.

B. ESP OBJECTIVES & REGULATORY CONTEXT

Pursuant to NAC § 704.9061, an ESP means a plan that:

1. Establishes the parameters of an energy supply portfolio for a utility for the three-year period covered by its Action Plan and which balances the objectives of:

   a) Minimizing the cost of supply;
   b) Minimizing retail price volatility; and
   c) Maximizing the reliability of energy supply over the term of the energy supply plan.

2. Is composed of a purchased power procurement plan, fuel procurement plan and risk management strategy.

Pursuant to NAC § 704.9494, the Commission can determine that the ESP is prudent if the following requirements are met:

- 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.

C. SUMMARY OF REQUESTS FOR COMMISSION APPROVAL

The Companies are requesting the Commission:

Load Forecast

- Find that the load forecast used in this ESP Update (the "2025 ESP Forecast"), as described in Section 2.A. (Electric Load Forecast) and Technical Appendix Item IRP LF-1, meets the requirements of NAC §§ 704.9321(1) (because they are based on substantially accurate data and are adequately documented, justified, demonstrated and defended), 704.9482 (because the 2025 ESP Forecast uses base load forecast), and 704.9482(7) and 704.922 (because the technical appendices provide sufficient detail as to how the 2022 ESP Forecasts were prepared to facilitate the evaluation of the validity of the assumptions and the accuracy of the data used).

- Find that the 2025 ESP Forecast is suitable for making planning decisions during the ESP Update period 2026-2027

Power Procurement/Sales Plan

- Accept and approve the power procurement plan, which includes the following elements:

  - The Companies propose to continue the four-season laddering strategy to fill the remaining open positions in 2026, continue filling the 2027 open positions and begin filling 2028 open positions. This plan is consistent with the laddering strategy for closing the open power position, which was most recently approved in Docket No. 24-05041. The power procurement laddering strategy will be executed in coordination with the physical gas procurement plan.

  - The Companies propose to continue to negotiate and transact directly with counterparties as a supplement to the current request-for-proposal process. The Companies will evaluate all available products and determine the most prudent transaction plan based on cost and deliverability.

- A commitment by the Companies to continuously monitor the portfolio and seek to make short-term and forward purchases when economic or needed to serve native load. Any proposed purchases of greater than three years in duration will be submitted to the Commission for approval in a resource plan filing or amendment in accordance with NAC §§ 704.9113 and 704.9512(1).

- A strategy and plan to make purchases and sales to optimize the value of the overall supply portfolio for the benefit of retail customers.

- An obligation on behalf of the Companies to monitor their renewable portfolios on a continuous basis to ensure that sufficient renewable energy and portfolio energy credits ("PCs") are maintained to comply with the State of Nevada's Renewable Portfolio Standard ("RPS"), and undertake cost-effective opportunities to fill any new needs that may arise. Current projections indicate that no additional purchases will be required during the ESP period to meet the RPS.

- Find, consistent with NAC § 704.9494(3), that the power procurement strategy is prudent.

Physical Gas Procurement Plan[1]

- Accept and approve the Companies' plan to implement the four-season laddering strategy originally approved by the Commission in Docket No. 09-09001 to procure physical gas. Projected physical gas requirements procured through the laddering strategy will be procured with indexed products, subject to a cap on the premium, which can be exceeded with prior approval from the Risk Committee. Consistent with the Stipulation in Docket No. 09-09001, if the Companies exceed the premium cap, and the procured gas that exceeded the premium cap is not the least cost supply alternative, they will provide written notice to the Commission's Regulatory Operations Staff ("Staff") and the Bureau of Consumer Protection ("BCP").

    - A strategy and plan to make purchases and sales to optimize the value of the overall supply portfolio for the benefit of retail customers.

- Find, consistent with NAC § 704.9494(3), that the physical gas procurement strategy is prudent.

[1] The Companies' "fuel procurement plan" consists of several distinct elements; namely, the physical gas procurement plan, the gas transportation plan, the gas hedging plan and the coal procurement plan.

Gas Transportation Plan

- Accept and approve the gas transportation plan, which includes the following elements:
  - Approval to maintain the Companies' current natural gas transportation portfolios. For Nevada Power, this requires authority to maintain seven existing gas transportation contracts with Kern River Pipeline and three with Southwest Gas Corporation. At Sierra, this requires authority to maintain a total of 33 existing gas transportation and storage contracts with TC Energy – Alberta, TC Energy – Foothills, TC Energy Gas Transmission Northwest ("GTN"), TC Energy Tuscarora Gas Transmission Company ("Tuscarora"), Great Basin Gas Transmission Company ("Great Basin") and Northwest Pipeline LLC ("NWPL") pursuant to rights of first refusal and evergreen rights. The total projected annual costs for firm transportation contracts at both Nevada Power and Sierra are approximately $117.5 million.
- Find, consistent with NAC § 704.9494(3), that the gas transportation strategy is prudent.

Gas Hedging Plan

- Approval to continue the current hedging strategy and acquire no natural gas hedges covering the ESP Update 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.
- The Companies will continue bi-annual workshops with Staff and the BCP to review implementation of the approved no-hedge gas hedging strategy.
- An affirmative finding, consistent with NAC § 704.9494(3), that the Companies' gas hedging strategy is prudent.

Risk Management Strategy

- Acceptance and approval of the Companies' risk management strategy and a finding that the strategy identifies risks inherent in procuring and obtaining a supply portfolio and establishes the means by which the utility plans to address and balance or hedge the identified risks related to cost, price volatility and reliability.
- An affirmative finding consistent with NAC § 704.9494(3) that the risk management strategy is prudent.

Commission Directives

A finding that the Companies have satisfied the following Commission directive:

- The Commission's order approving the stipulation in Docket No. 20-09002 accepting the Companies' plan to continue conducting bi-annual gas hedging workshops with Staff and BCP to review the implementation of the constituent elements of the ESP and the approved gas hedging strategy.

Determination of Prudence

Pursuant to NAC § 704.9494, the Companies request that the Commission determine the elements of the ESP are prudent by finding that the 2025 ESP Update:

- 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.

- Optimizes the value of the overall supply portfolio of the utilities for the benefit of their bundled retail customers.

- Does not contain any feature or mechanism that would impair the restoration of the creditworthiness of the utilities or would lead to a deterioration of the creditworthiness of the utilities.

Finally, the Companies ask that the Commission grant their request for confidential treatment of information filed under seal, including copyrighted and proprietary data of third parties, coal price forecasts, natural gas price forecasts, power price forecasts, large customer load information, the proposed cap on premiums to be paid for physical gas supplies, and the production cost modeling outputs.

For more information on the Companies' request for a determination of prudence of the 2025 ESP Update see Section 8.

D. OVERVIEW OF THE ENERGY SUPPLY PLAN

1. POWER PROCUREMENT PLAN

Based on the 2025 ESP Load Forecast, the Companies have open capacity positions in the summers of 2026 and 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 up to the respective anticipated summer open positions with firm products prior to respective the summer.

The Companies propose to implement a four-season laddering strategy to close the remaining open power positions in 2026 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 as approved in the 2024 Joint Integrated Resource Plan ("IRP"). 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(1). Additional information regarding the closing of the open positions in the power procurement plan is provided in Section 4.C.

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 update period.

The Companies anticipate meeting their RPS credit obligations in the year 2026 but not in the year 2027 of the ESP Update planning period. In 2027, Nevada Power is expected to be non-compliant and Sierra is expected to be non-compliant. This ESP Update 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.

For more detail on the purchased power procurement plan, see Section 4. For more detail on the RPS compliance outlook, see Section 2.D.

2. FUEL PROCUREMENT PLAN

The fuel procurement plan is made up of three components: (1) a physical gas procurement plan, (2) a gas transportation plan, and (3) a gas hedging plan.

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.

Additionally, the Companies monitor the natural gas portfolio monthly, weekly, and daily. The Companies will make short-term purchases and sales for balancing and optimization activities for the natural gas portfolio based on the needs of the system. This practice will be continued over the ESP period. Additional information regarding the Companies' physical gas procurement plan is provided in Section 5.A.

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 takes delivery of natural gas from two interstate pipelines, Great Basin and Tuscarora. Great Basin receives gas supplies upstream from NWPL, 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 GTN, near Malin, Oregon, which is connected to the gas producing regions of Western Canada Sedimentary Basin Alberta through TC Energy's system. The gas supply source for Malin gas is predominantly in the Province of Alberta, Canada. TC Energy's Alberta pipeline system carries the gas commodity from the AECO producing areas to the Alberta/British Columbia border. There, TC Energy's Alberta system interconnects with TC Energy's Foothills system, which transports gas to GTN's system at the U.S./Canadian border near Kingsgate, Idaho.

The Companies are seeking approval to maintain their current natural gas transportation portfolios. The contracts are listed in Figures ESP-39 and ESP-40. Additional information regarding the Companies' gas transportation plan is provided in Section 5.B.

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.

3. COAL SUPPLY PLAN

The coal requirements for Valmy are discussed in Section 2.H. Valmy's coal requirements for 2025 will be filled with short term supply contracts transacted directly with counterparties, if needed, as a supplement to the request-for-proposal ("RFPs") process.

4. 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.

5. 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."

SECTION 2 – POWER AND FUEL REQUIREMENTS

A. NV ENERGY ELECTRIC LOAD FORECAST

The 2025 ESP Forecast utilizes the load forecast approved in the 2024 Joint IRP ("2024 IRP") filing, with updates to extend the date during which the loads of Liberty Utilities (CalPeco Electric) LLC ("Liberty") remain as bundled service from December 2025 to May 2027,[2] and updates to the large customer major project forecast components. The forecast was completed in August 2025 using data through December 2024 and covers the remaining two years of the action plan period (2026 and 2027). The sections below provide a summary of the data for the 2025 ESP period, methodology, and results of this forecast update.

Load Forecast Summary

For the remaining two-years of the action plan period (2026 through 2027), the expected growth in annual retail energy for the Companies' combined system is forecasted to grow from 36,423 GWh in 2026 to 40,615 GWh in 2027, a Compound Annual Growth Rate ("CAGR") of 8.8 percent. The combined coincident peak MW is forecasted to grow from 8,812 MW in 2026 to 9,231 MW in 2027, representing a CAGR of 1.1 percent over the two-year action plan period.

Nevada Power's system is forecasted to grow from 24,108 GWh in 2026 to 25,922 GWh (an increase of 1,815 GWh), with a peak increase of 246 MW from the 2026 peak of 6,753 MW to 6,999 MW in 2027. This equates to a 6.2 percent CAGR in energy and 2.4 percent CAGR in Nevada Power's peak over the two-year action plan period.

At Sierra, the expected growth in annual energy is forecasted to increase from 12,315 GWh to 14,693 GWh (an increase of 2,377 GWh), with a 248 MW increase from the 2026 peak of 2,279 MW to 2,527 MW in 2027. This growth equates to a 13.7 percent energy CAGR and 7.7 percent CAGR for Sierra's peak over the 2026 to 2027 period.

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[2] As discussed in more detail in Section 2.B below.

Figure ESP-1 summarizes the Annual Peak MW and GWh energy differences between the 2025 ESP Update forecast and the forecast approved in the 2024 IRP filing.[3] Changes to Sierra's large customer projects have pushed these load additions to later years from those considered previously in the 2024 IRP.

FIGURE ESP-1
ANNUAL PEAK (MW) AND ENERGY (GWH) DIFFERENCES

		Peak (MW)		Energy (GWh)	
		2026	2027	2026	2027
Nevada Power	2025 ESP Update	6,753	6,999	24,108	25,922
	2024 IRP	6,608	6,674	22,875	23,161
	Difference	145	325	1,232	2,762
	Percent Difference	2.2%	4.9%	5.4%	11.9%
Sierra	2025 ESP Update	2,279	2,527	12,315	14,693
	2024 IRP	2,381	2,495	12,788	13,654
	Difference	(102)	32	(473)	1,038
	Percent Difference	-4.3%	1.3%	-3.7%	7.6%
NVE	2025 ESP Update	8,812	9,231	36,423	40,615
	2024 IRP	8,787	8,895	35,663	36,815
	Difference	25	336	759	3,800
	Percent Difference	0.3%	3.8%	2.1%	10.3%

[3] Docket No. 25-05041, Order dated December 27, 2024, at ¶¶ 520-530.

Figure ESP-2 demonstrates the monthly coincident peak load forecast for the remaining two years of the action plan period (2026 and 2027).

FIGURE ESP-2
MONTHLY NV ENERGY PEAK LOAD FORECAST (2026-2027)

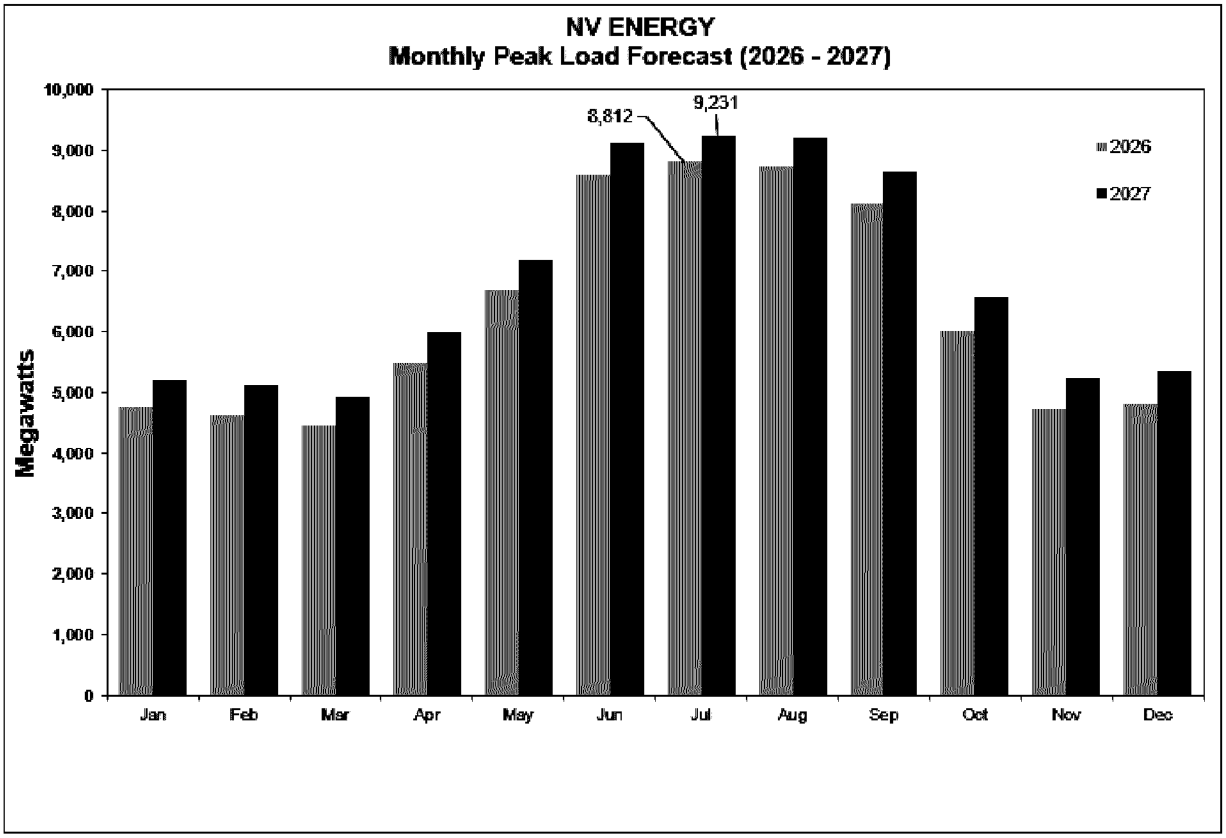


Figure ESP-3 shows the Companies' projected load duration curve for 2026. This is the distribution of load across the number of hours in the year and represents a load factor of 46.7 percent overall.

FIGURE ESP-3
NV ENERGY 2026 LOAD DURATION CURVE

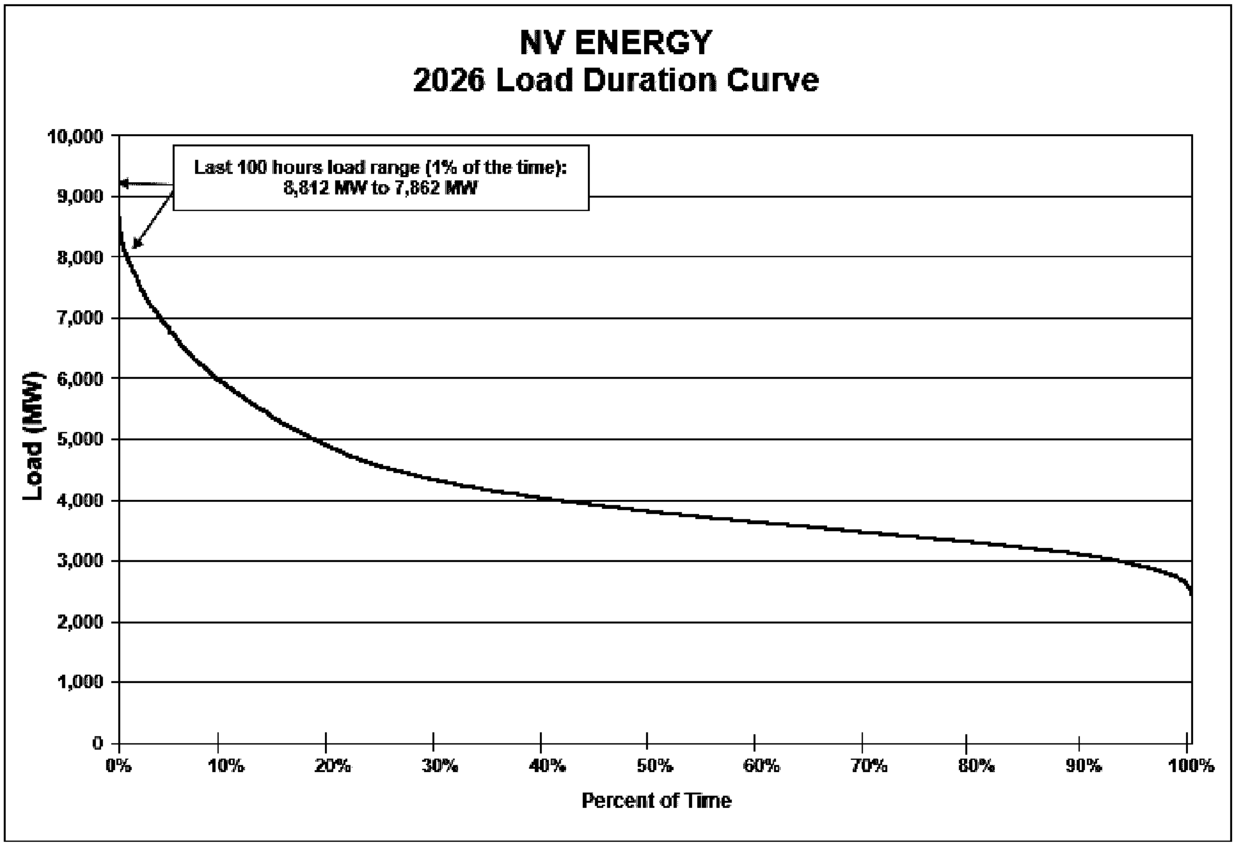
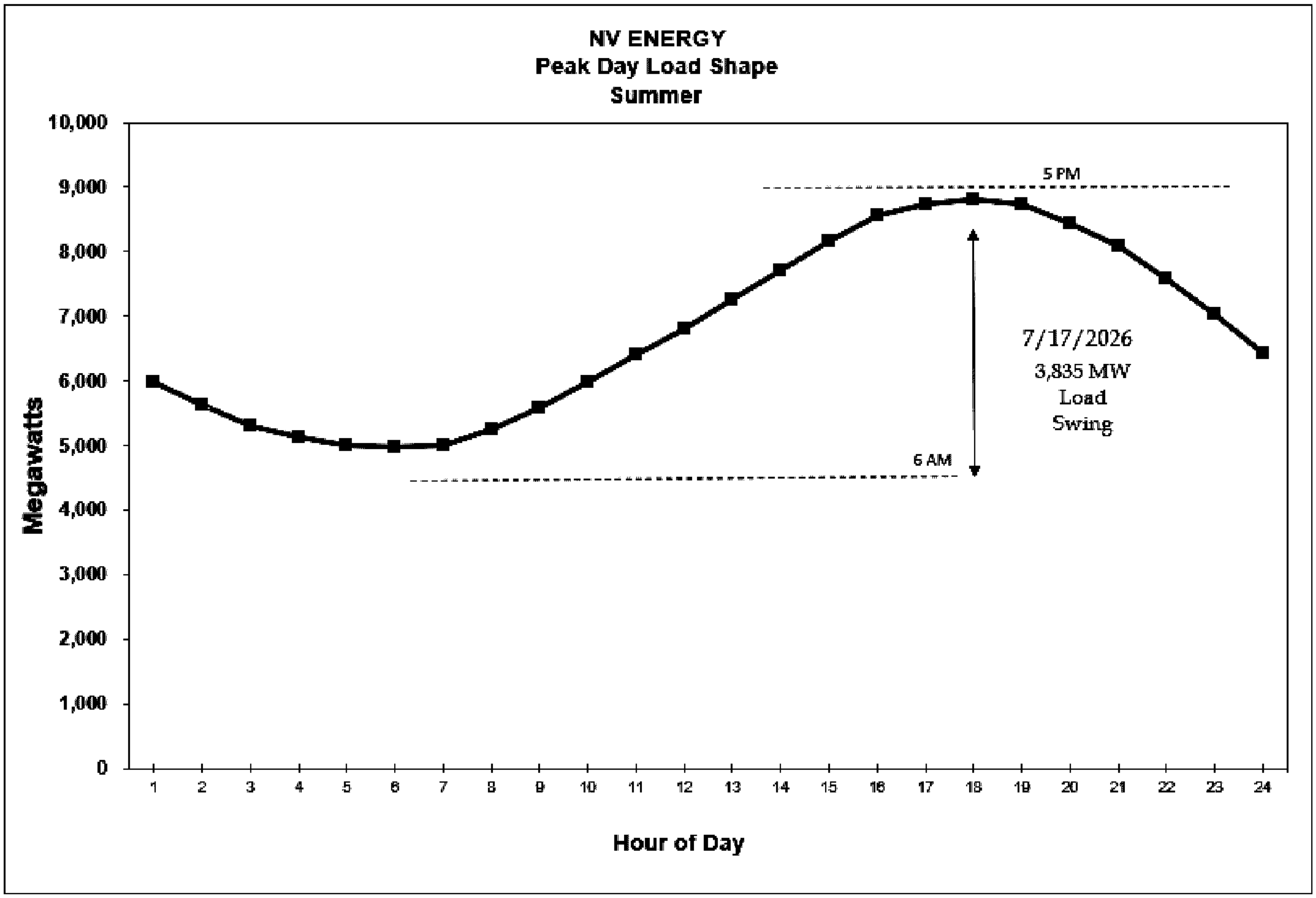


Figure ESP-4 reflects the expected fluctuation in hourly load during the summer peak day in July of 2026, which is expected to experience a range of 3,847 MW, or 43.8 percent of the daily peak, between the minimum and maximum loads. The presented load shape is representative of the near-term summer peak load shape for the Companies.

FIGURE ESP-4
NV ENERGY PEAK DAY LOAD SHAPE FORECAST



Load Forecast Process

The 2025 ESP Forecast begins with the load forecast recently approved by the Commission in the 2024 IRP filing. It is based on the same bottom-up data-driven modelling approach and incorporates updates for the continued provision of energy to Liberty through May 2027, and current information regarding the large customer major projects forecast component.

Population and Economic Condition Inputs Forecast

No changes have been made to the Companies' population projections or economic condition inputs from those approved by the Commission in the 2024 IRP filing.

Normal Weather Conditions

No changes have been made to the Companies' normal weather condition assumptions from those approved by the Commission in the 2024 IRP filing.

End-Use Saturation and Efficiency Trends

No changes have been made to the Companies' end-use saturation and efficiency trend information from those approved by the Commission in the 2024 IRP filing.

Net-Energy Metering (NEM)

No changes have been made to the Companies' NEM adoption levels, and resulting load forecast component, from those approved by the Commission in the 2024 IRP filing.

Behind the Meter Energy Storage

Due to the current limited number of customers with behind the meter energy storage installed on their premises, the Companies continues to not include any specific adjustments related to energy storage estimates to the approved 2024 IRP forecast. Customers who have installed energy storage as part of a rooftop solar installation are included in the total population of these NEM customers but are not considered separately. At this time, any expected impacts beyond general NEM characteristics are small and therefore have not been separately included in the approved 2024 IRP Forecast.

Impacts for Electric Vehicles

No changes have been made to the Companies' EV adoption levels, and resulting load forecast component, from those approved by the Commission in the 2024 IRP filing.

Impacts on Annual Energy Savings from DSM

No changes have been made to the DSM savings adjustments approved by the Commission in the 2024 IRP filing.

Large Customer Forecast

The Companies include recent information updates to the large customer major projects component for this 2025 ESP forecast. In total, the Companies included 292 MW of expected incremental load for all of these bundled projects in 2026 and 624 MW in 2027. While these large customer projects continue their increasing trend over recent years, in total, these projects show 94 MW lower loads in 2026 but 345 MW higher in 2027, relative to the approved 2024 IRP forecast, as these projects exhibit later ramp-up schedules.

Overall, there are 46 bundled service large customer projects included in this forecast update that represent 4,527 MW of customer requested peak capacity requirements through 2027. These projects are located primarily within the Tahoe-Reno Industrial Center ("TRIC") area in Sierra's service territory and the Apex area at Nevada Power. In this 2025 ESP forecast update, 21 of the 46 bundled service projects have signed customer Rule 9 agreements requesting 1,500 MW of bundled-service capacity by 2027 at Sierra and 250 MW of capacity at Nevada Power by 2027. The remaining 25 projects are in the engineering study phase and have requested 2,777 MW of capacity, with 883 MW at Sierra and 1,894 MW at Nevada Power over the same period.

Consistent with past practice, these requests are scaled down in the retail load forecast. Historically approximately 40 percent of study phase projects move forward. The loads of bundled service projects in the study phase saw an average 2027 reduction of 87 percent, while the loads of bundled service projects with signed Rule 9 agreements were reduced by 46 percent.

Impacts from DOS Customers

The Companies are required to include in each triennial Joint IRP filing a proposal for annual limits on the total amount of energy and capacity that eligible NRS Chapter 704B Large C&I customers may be authorized to purchase from providers of new electric resources during the three-year action plan period. In the 2024 IRP, the limit approved for the current three-year action plan period for Nevada Power was set at 260,489 MWh, which translates into an average hourly 29.7 MW load. Sierra's limit remains unchanged at 0 MW, due to continued system import capacity constraints on the system. Nothing in this updated electric load forecast affects these limits. To date, zero customers have elected to exit bundled service during the current three-year action plan period.

B. CAPACITY REQUIREMENTS

The Companies require enough firm capacity to cover their projected electric load plus their respective planning reserve margin ("PRM") of 12.5 percent.[4] Due to the development of portfolios with large quantities of variable renewable resources in which available resources decline rapidly in the evening hours, the current paradigm, established in the 2021 ESP, evaluates the hour with the largest open position in addition to the traditional evaluation of the peak load hour, to ensure reliability. Traditionally, these two hours were one and the same, but with increasing amounts of renewable resources, the later evening hours now exhibit significantly larger open positions. Therefore, the Companies close the largest open capacity position in the later evening hours rather than at the peak load hour. This paradigm shift, enacted in 2021, increases reliability and reduces the risk of being reliant on short-term power markets in the evening hours.

The largest open capacity positions under this new methodology are 1,020 MW in 2026 and 1,926 MW in 2027.

[4] *See* 2024 Joint IRP, Docket No. 24-05041, Volume 8 at 216 of 393.

Since the filing of the 2024 ESP, several material developments have contributed to increased open capacity positions within the Sierra service territory, as well as increased energy needs and modeled loss of load hours ("LOLH") discussed more in Section 2.C – Energy Requirements. These developments include:

1. *Increased Load Forecast.* As detailed in part 2.A (Load Forecast), Sierra's 2027 projected load has increased relative to the 2024 ESP. Included in this load forecast, Liberty's load servicing agreement has been extended through May 2027, resulting in an incremental energy requirement of approximately [redacted] in 2026, [redacted] in 2027, and an incremental capacity requirement of approximately [redacted] in July 2026. An overall increased requirement of [redacted] occurs in the hour of greatest need for Sierra in 2027.

2. *Reduction in Sierra's Available Resources.*
   a. Several factors have contributed to a net reduction in available capacity of 98 MW in 2026 and 93 MW in 2027 and reduced available energy for Sierra, compared to the 2024 ESP, including:
      1. Cancellation of Ormat's North Valley 2 geothermal project;
      2. A delay in the commercial operation date ("COD") for Ormat's Lone Mountain geothermal project;
      3. Near-term performance adjustments and supply table updates for contracted resources based on recent performance;
      4. Removal of distributed and demand side resource capacity not approved in the 2024 Joint IRP; and
      5. Updated allocation of the 90 MW of reserves held for Open Access Transmission Tariff ("OATT") customers between Sierra and Nevada Power.
   b. In addition, Liberty's Luning Expansion (50 MW solar photovoltaic and 62 MW battery), which was to be in service in June 2025, would have been part of the extension of Liberty's load servicing agreement through May 2027 but for its cancellation.

Figure ESP-5 ("L&R Tables") illustrates the current paradigm and details the resources necessary for the Companies to meet the forecasted customer load, including planning reserve requirements, by summer hours 5:00 p.m. through 8:00 p.m. for 2026-2027. Hours 9:00 p.m. through 11:00 p.m. were also analyzed and while open positions were observed, they were not the hour with the largest open position and were excluded from the table for brevity. The L&R Tables reflect the unforced capacity accounting methodology used in the Companies' 2024 ESP and described in the 2024 Joint IRP (Docket No. 24-05041).

FIGURE ESP-5
2026-2027 LOADS & RESOURCES

2026	Hour Ending 5:00 pm				Hour Ending 6:00 pm				Hour Ending 7:00 pm				Hour Ending 8:00 pm			
	Jun-26	Jul-26	Aug-26	Sep-26	Jun-26	Jul-26	Aug-26	Sep-26	Jun-26	Jul-26	Aug-26	Sep-26	Jun-26	Jul-26	Aug-26	Sep-26
Maximum Coincident System Load	8,531	8,742	8,742	8,102	8,604	8,812	8,812	8,111	8,452	8,726	8,726	7,802	8,066	8,430	*8,430*	7,420
Planning Reserves 12.5%	1,066	1,093	1,093	1,013	1,075	1,102	1,102	1,014	1,057	1,091	1,091	975	1,008	1,054	1,054	927
Required Resources	9,598	9,835	9,835	9,114	9,679	9,914	9,914	9,125	9,509	9,817	9,817	8,777	9,075	9,484	9,484	8,347
Generation Totals	6,200	6,200	6,200	6,200	6,200	6,200	6,200	6,200	6,200	6,200	6,200	6,200	6,200	6,200	6,200	6,200
Demand Response	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234
Generation Existing - PPA	152	177	178	209	152	177	178	209	152	177	178	209	152	177	178	209
Market Transactions	700	725	725	725	700	725	725	725	700	725	725	725	700	725	725	725
Renewables	2,982	3,255	3,127	2,815	2,418	2,729	2,343	1,700	1,339	1,689	1,550	1,534	1,132	1,503	1,515	1,539
OATT Reserves	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*
Total Available Resources	10,179	10,501	10,374	10,093	9,614	9,975	9,590	8,978	8,536	8,935	8,797	8,811	8,328	8,749	8,762	8,817
Long/(Open) - Joint System	581	666	540	979	(65)	62	(323)	**(147)**	**(973)**	**(882)**	**(1,020)**	34	(747)	(735)	(722)	470

2027	Hour Ending 5:00 pm				Hour Ending 6:00 pm				Hour Ending 7:00 pm				Hour Ending 8:00 pm			
	Jun-27	Jul-27	Aug-27	Sep-27	Jun-27	Jul-27	Aug-27	Sep-27	Jun-27	Jul-27	Aug-27	Sep-27	Jun-27	Jul-27	Aug-27	Sep-27
Maximum Coincident System Load	9,058	9,147	9,147	8,636	9,129	9,231	9,231	8,647	8,977	9,202	9,202	8,351	8,584	8,915	8,915	7,963
Planning Reserves 12.5%	1,132	1,143	1,143	1,079	1,141	1,154	1,154	1,081	1,122	1,150	1,150	1,044	1,073	1,114	1,114	995
Required Resources	10,190	10,290	10,290	9,715	10,270	10,385	10,385	9,728	10,100	10,352	10,352	9,395	9,657	10,030	10,030	8,958
Generation Totals	6,207	6,207	6,207	6,207	6,207	6,207	6,207	6,207	6,207	6,207	6,207	6,207	6,207	6,207	6,207	6,207
Demand Response	249	249	249	249	249	249	249	249	249	249	249	249	249	249	249	249
Generation Existing - PPA	148	176	173	206	148	176	173	206	148	176	173	206	148	176	173	206
Market Transactions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewables	3,685	3,560	3,438	3,137	3,131	3,045	2,667	2,036	2,072	2,019	1,886	1,874	1,872	1,840	1,854	1,880
OATT Reserves	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*
Total Available Resources	10,199	10,103	9,977	9,709	9,645	9,587	9,207	8,608	8,585	8,562	8,426	8,446	8,386	8,382	8,393	8,452
Long/(Open) - Joint System	9	(188)	(313)	(7)	(625)	(797)	(1,178)	**(1,120)**	**(1,514)**	**(1,790)**	**(1,926)**	(949)	(1,271)	(1,648)	(1,637)	(506)

In the L&R Tables, the capacity resources available to serve forecasted customer load consist of internal generation and purchases. Firm purchased power resources include purchases from existing and planned renewable energy projects, internal power contracts (within the Companies' system) and external power contracts (outside the Companies' system). External generation purchases require system import transmission capacity. In addition, resources in specific locations within the Companies' control area consume or reduce import capability. The north/south allocation of OATT reserves was adjusted to align with recent OATT customer loads. Total available resources (generation and purchases) are shown at the bottom section of the L&R Tables, along with any open capacity positions. Open ("short") positions are indicated as negative values.

The Companies continuously assess their procurement plans and strategies based upon changing market conditions and needs. The Risk Committee reviews supply plans approximately once a month. To the extent that circumstances such as delays, shortfalls, and/or cancellations of any renewable resources occur, Resource Planning would alert the Risk Committee of the changes to the open capacity positions. To the extent that the change in the open capacity position dictates a change in strategy, Staff and the BCP would be notified, and the Companies would obtain appropriate approvals of such deviations where applicable.

C. ENERGY REQUIREMENTS

In the ESP context, the Companies can meet the energy requirements of their retail customers in several ways, including daily and real-time hourly purchases, existing generation, and forward products (such as call options or forward block power). The total open position is the portion of projected energy requirements that is otherwise unmet, either physically or economically, by other sources given operational constraints (*e.g.*, operating reserve requirements, the ramp rates of the units,[5] minimum unit load levels, and must-run requirements).

As described in the prior section, since the filing of the 2024 ESP, several material developments have contributed to increased energy needs and modeled LOLH within the Sierra service territory. Figure ESP-6 ("2026–2027 Modeled Sierra Unserved Energy") presents the modeled outcomes related to expected unserved energy ("EUE") and LOLH for Sierra using the mean values from 50 iterations of randomized forced outages. No EUE or LOLH exist for Nevada Power in the modeled outcome.

FIGURE ESP-6
2026-2027 Modeled Sierra Unserved Energy[6]

	2026	2027
EUE (MWh)	50	130
EUE (as percentage of load)	0.0004%	0.0008%
EUE Hourly Maximum (MW)	7.6	9.3
EUE Hourly Mean (MW)	1.5	3.4
LOLH (hours/year)	1.3	0.9

The Companies monitor their energy requirements on a continuous basis to determine when and what quantities of additional energy are required to ensure continued reliable electric service and will undertake cost-effective opportunities to fill such needs. This is discussed further in Section 4 – Power Procurement Plan.

[5] The ability to shut down or rapidly ramp down a unit each night is a critical feature for determining which units are economic to run. If a unit is able to shutdown (cycle) each night, then the question of whether the unit is "in-the-money" is relatively simple. If the cost of operation is less than the market prices of energy, the unit is economic.
[6] EUE as a percentage of load is calculated by dividing Sierra's modeled annual EUE by Sierra's total annual load. EUE Hourly Maximum is defined as the highest EUE observed in the model results in any single hour during the year. EUE Hourly Mean is defined as the average EUE during hours in which EUE is observed in the model results.

D. RENEWABLE ENERGY PLANNING

The Companies vigilantly plan for their ongoing PC requirements, recognizing there are still uncertainties and risks inherent in renewable energy production and renewable project development. The planning strategy incorporates all rules, regulations and requirements codified in NRS §§ 704.7801 through 704.7828. In determining future PC needs the Companies must carefully consider several overarching objectives:

- Full compliance with an escalating and compressed RPS schedule: 34 percent starting 2024, 42 percent by 2027, and 50 percent by 2030;
- Ensuring enough renewable capacity to satisfy a strong and growing demand from the Nevada business community to meet their energy needs from carbon-free, sustainable energy; and
- Developing a long-term strategy to build a generating portfolio that is capable of progressing towards the Nevada policy goal for an amount of zero-carbon generation equal to retail sales in 2050.

The Nevada RPS is stated in terms of the number of PCs required for compliance. A PC is equal to one kilowatt-hour ("kWh") of renewable energy generated or one kWh of energy saved through an efficiency program. Similarly, one MWh of energy from renewable resources or savings from an efficiency program would result in one thousand PCs, or a "kPC" — however, beginning in 2025, PCs from energy efficiency measures are no longer eligible for compliance, as specified in NRS § 704.7821(2)(a)(4).

In their most recent annual RPS compliance filing, Docket No. 25-04014, Nevada Power and Sierra both exceeded their respective 2024 RPS credit requirements of 34 percent. Nevada Power ended 2024 at 45.6 percent, Sierra at 50.1 percent, both records. Adding to Sierra Pacific's existing renewable capacity, Ormat recently completed a repower of the Ormat Western Geothermal Portfolio (OWGP) geothermal facility. The repower increased the facility's capacity from 17.7 MW to 20 MW through plant improvements. The repower declared commercial operation on January 1, 2025. This improvement will enhance the total amount of renewable energy and Portfolio Credits ("PCs") available to meet the energy needs of Sierra's customers.

As of June 30, 2025, Nevada Power had approximately 2,724-MW of contracted and 165 MW of owned renewable generating resources operating and delivering renewable energy to meet the energy needs of its customers. In addition, Nevada Power ended June 2025 with four solar PV and ESS projects under development: Sierra Solar, Dry Lake East, Boulder Solar III, and Libra – pending final allocation of the Libra project between Nevada Power and Sierra.

Figure ESP-7, below, lists Nevada Power's renewable pipeline of projects, showing the facility's name, resource type, approval docket number, projected commercial operation date, nameplate capacity (AC), storage capacity, and energy and capacity allocation, as approved by the Commission in the approval order.

FIGURE ESP-7
NEVADA POWER PIPELINE PROJECTS

Approved, Under development / Under Construction / Under Going Commissioning

	Facility	Resource Type	Approval Docket No.	Projected COD	Nameplate MW AC	Storage Capacity	Energy / Capacity Allocation NPC	SPPC
1	Sierra Solar [a]	Solar PV	23-08015	04/01/27	400	400	**40**	360
2	Libra [b]	Solar PV	24-05041	12/01/27	700	700	**TBD** [b]	TBD [b]
3	Dry Lake East	Solar PV	24-05041	12/01/26	200	200	**200**	0
4	Boulder Solar III (2024)	Solar PV	24-05041	12/01/26	128	128	**128**	0
					1,300	1,300	**240**	360

a. 10 percent of the energy and PCs derived from Sierra Solar are to be assigned to Nevada Power per the order (Docket No. 23-08015)

b. Energy, capacity, and PCs have not been allocated to either NPC or SPPC per Commission Order (Docket No. 24-05041)

As of June 30, 2025, Sierra had approximately 949 MW of renewable contracted generating resources and approximately 20 MW of company-owned generating resources operating and delivering renewable energy to meet the energy needs of its customers. In addition, Sierra ended June 2025 with two solar PV and ESS and one geothermal portfolio in various stages of development. Like Nevada Power, battery storage offers flexibility by allowing Sierra to store generation when demand and prices are low and release it back to the grid when demand and prices start to rise. This helps optimize must-take renewable resources, like solar PV, where generation and load do not always align.

Figure ESP-8, below, lists Sierra's future projects, showing the facility name, resource type, approval docket number, projected commercial operation date, nameplate capacity (AC), storage capacity, and energy and capacity allocation, as approved by the Commission in the approval order; the Libra project has not yet been allocated to either Sierra or Nevada Power and is thus listed as TBD.

FIGURE ESP-8
SIERRA POWER PIPELINE PROJECTS

	Facility	Resource Type	Approval Docket No.	Projected COD	Nameplate MW AC	Storage Capacity	Energy / Capacity Allocation SPPC	NPC
1	Ormat Portfolio (OWGP, LLC)							
	> Galena 1	Geothermal	22-11032	02/01/27	15		**15**	
	> Desert Peak 2	Geothermal	22-11032	02/01/28	10		**10**	
	> Galena 3	Geothermal	22-11032	01/01/29	15		**15**	
	> Lone Mountain	Geothermal	22-11032	10/01/28	15		**15**	
	> Pinto	Geothermal	22-11032	01/01/27	15		**15**	
2	Sierra Solar [a.]	Solar PV	23-08015	04/01/27	400	400	**360**	40
3	Libra [b.]	Solar PV	24-05041	12/01/27	700	700	**TBD** [b.]	TBD [b.]
					1,170	1,100	**430**	40

a. 90 percent of the energy and PCs derived from Sierra Solar are to be assigned to Sierra per the order (Docket No. 23-08015)

b. Energy, capacity, and PCs have not been allocated to either NPC or SPPC per Commission Order (Docket No. 24-05041)

<u>RPS Compliance Planning</u>

The expected PC supply was determined starting with the current portfolio of approved projects, including operating and under development or contemplated by the Companies. The following assumptions are built into the forecast:

- Existing power purchase agreements ("PPAs") expire in accordance with the contract terms and are not automatically renewed.[7] The Companies reached out to all geothermal supplier counterparties whose contracts will be expiring in the next five years to commence discussions related to future extensions; The Beowawe, Burdett, Desert Peak 2, and Galena 3 contracts have been renegotiated in the OWGP, Docket No. 22-11032. A contract extension for the Stillwater Geothermal project is still being negotiated;

- The Companies adjusted the expected amount of energy and PCs from renewable facilities for the period of 2025-2027 in cases where the historic generation, based on two or more years of data, consistently varied from that of the contractual or expected supply table. This is consistent with the methodology that the Companies used for the past several years in developing their IRPs and ESPs. This adjustment recognizes that options to address underperformance within a shorter planning window are limited. It also aligns the short-term and long-term plans;

[7] This does not imply that the Companies would rule out renewing existing agreements. Rather, it recognizes the uncertainty as to whether the resource could continue to support ongoing generation, and whether the Companies and the counterparties can come to terms on renewing the agreement.

- The projected number of PCs derived from the Renewable Generations incentive programs plateaued in 2020 with the last of the incentivized solar systems now installed. Starting in 2021, the expected number of PCs from incentivized rooftop solar is forecasted to begin decreasing by 0.5 percent per year as these systems age and their output slowly begins to decline;[8]

- Solar PV systems placed into service before December 31, 2015, qualify for the solar multiplier; systems placed into service after do not qualify;

- The plan assumes that the percent of annual PC requirements met from DSM measures are limited to no more than 10 percent of the credit total for 2021 through 2024 before dropping to zero effective 2025. The plan also assumes, based on current DSM kPC projections, that Sierra did not have a sufficient number of DSM PCs to completely fill the 10 percent cap in 2024. To address the gap, Nevada Power transferred 167,531 credits to Sierra;[9]

- Surplus PCs are carried forward without limitation and the plan assumes no surplus PC sales;

- The plan assumes that generation from both company-owned solar PV systems and PPA projects would be degraded starting the year following the first full year of operation. Annual degradation is based on project specific data provided by the solar panel suppliers or project developers;

- Geothermal generation would continue to qualify for station usage credits, while all other technologies would no longer qualify;

- The plan accounts for all Commission approved and existing NV GreenEnergy Rider ("NGR") and energy supply agreements ("ESAs") as of June 30, 2025, where PCs associated with all or a portion of the output from a renewable facility(ies) have been assigned to a customer under the NGR, the Market Price Energy or Large Customer Market Price Energy tariffs, and therefore, cannot be used by the Companies in meeting their RPS credit requirements. It also includes 2025 NGR Option 1 capacity submitted for Commission approval in the Companies' NGR Open Season Annual Report, Docket No. 25-03025. The NGR forecast, incorporated in the Assessment of Need discussed in the Economic Analysis Section of the 2024 Joint IRP narrative,

[8] Annual degradation is based on the median degradation rate published by National Renewable Energy Laboratory, available at https://www.nrel.gov/state-local-tribal/blog/posts/stat-faqs-part2-lifetime-of-pv-panels.html.
[9] Nevada Power received approval in the 2023 Annual RPS Compliance filing to transfer a small number of stranded DSM credits to Sierra so Sierra could fill the 10 percent cap. Docket No. 24-0417, Order dated July 12, 2024, at p. 8.

conservatively assumes the maximum amount of 100 MW and associated PCs per year are required going forward.

- The plan adjusts the retail sales total that is used to calculate the RPS requirement to exclude sales to bundled NGR or ESA customers, and other customers participating in a program of optional pricing that includes the transfer of PCs above that required for RPS compliance in an amount that is equal to the number of credits transferred to or retired on behalf of the participating customers;

- The plan assumes that the net energy produced by Hoover and allocated to Nevada Power counts towards meeting the RPS;

- The plan assumes no changes to the existing statutory and regulatory RPS regime;

- The base plan includes the Ormat Portfolio, which has been updated and now consists of six geothermal plants totaling 120 MW with staggered COD dates as described in further detail below. Sierra will be the sole off taker of the energy and PCs from the Ormat Portfolio. The total number of PCs for the Ormat Portfolio PPA includes estimated station usage PCs. Certain geothermal station usage, the energy for the extraction and transportation of geothermal brine or used to pump or compress geothermal brine, is eligible for certification under NRS § 704.78215(3)(b). Station usage PCs for this facility were estimated at 15 percent of net;

- The annual amount of energy produced by solar PV systems paired with BESS has been reduced to account for battery losses which is site-specific but typically further degrades by less than one percent annually. The adjustment recognized that not all of the energy produced by solar PV arrays paired with energy storage will be delivered real-time to the grid. Some of the energy will be stored and dispatched at a later time when needed. The process of charging and discharging the batteries will result in energy losses;

- An adjustment has been added to the model to capture the generation and PCs lost due to curtailment. The curtailed amount is estimated from the excess energy in the PLEXOS model as an annual amount, and varies year to year. This adjustment recognizes that as renewable energy becomes the dominant source of generation, there may be times when the transmission system cannot accommodate all of the energy being produced, making generation curtailment necessary to maintain grid integrity;

- The plan assumes the contract with Liberty is extended through May 31, 2027, the date that Greenlink West is expected to be placed in service that will allow for Liberty to transition to Network Integration Transmission Service;

- In the absence of an approved allocation, Libra Solar and ESS is allocated 100 percent to Nevada Power, as proposed in the 2024 Joint IRP (Docket No. 24-05041);

- The plan includes a modified load forecast that is detailed in Section 2.A; and

- The plan assumes a reduction in previously forecasted PCs due to the Community Solar Program proposed by the Companies in the 2024 Joint IRP (Docket No. 24-05041) not receiving approval in the Commission's Order.

RPS Compliance Planning

As previously stated, in forecasting renewable generation for IRP and ESP filings, the Companies account for trends in the operating performance of resources in their existing portfolio. In the long-term, if a renewable facility is failing to meet its contractual energy or credit obligations, the assumption is that the PPA counterparty will be able to initiate necessary actions to rectify the shortfall. This assumption is not necessarily true for short-term planning, where options to address underperformance within a shorter planning horizon are limited. This assumption also holds true in cases of over production as most renewable PPAs are must-take. Therefore, in developing the ESP and IRP, the Companies adjusted the expected amount of energy from certain renewable facilities, where historic generation varied more than six percent from that of the contractual or expected supply table. This adjustment applied to the 2024-2027 planning horizon.

Figure ESP-9 below is a summary of all projects and supply adjustments used in developing Nevada Power's RPS outlook. Note, the list below only includes projects that were approved by the Commission as of June 30, 2025.

FIGURE ESP-9
NEVADA POWER SHORT-TERM SUPPLY ADJUSTMENTS

					IRP/ESP Action Period			
Facility	Actual / Projected COD	NamePlate (AC)	Resouce	Type	2025 [a.]	2026 [a.]	2027 [a.]	
Blue Mountain 1 (Faulkner)	11/20/09	49.5	Geo	PPA	100%	100%	100%	
Desert Peak 2	04/17/07	25.0	Geo	PPA	100%	100%	100%	
Jersey Valley	08/30/11	22.5	Geo	PPA	90%	90%	90%	a.
McGinness Hills	06/20/12	96.0	Geo	PPA	100%	100%	100%	
Salt Wells	09/18/09	23.6	Geo	PPA	87%	90%	87%	a.
Stillwater (Geo & PV)	10/10/09	69.2	Geo/PV	PPA	91%	95%	91%	a.
Tuscarora	01/11/12	32.0	Geo	PPA	103%	105%	105%	
ACE Searchlight Solar	12/16/14	17.5	PV	PPA	100%	100%	100%	
Arrowhead Canyon (Moapa) Solar (30%)	12/01/22	60.0	PV	PPA	100%	100%	100%	b.
Boulder Solar I	12/09/16	100.0	PV	PPA	100%	100%	100%	
Boulder Solar III	06/01/27	127.9	PV	PPA	n/a	n/a	100%	
Copper Mountain V	07/23/21	250.0	PV	PPA	100%	100%	100%	
Dry Lake	03/15/24	150.0	PV	PPA	100%	100%	100%	
Dry Lake East	12/01/26	200.0	PV	PPA	n/a	100%	100%	
Eagle Shadow Mountain	05/10/23	300.0	PV	PPA	100%	100%	100%	
FRV Spectrum	09/23/13	30.0	PV	PPA	113%	113%	113%	a.
Gemini Solar	03/25/24	690.0	PV	PPA	100%	100%	100%	c.
Libra	12/01/27	700.0	PV	PPA	n/a	n/a	100%	
Mountain View Solar	01/05/14	20.0	PV	PPA	100%	100%	100%	
Nellis 2	11/23/15	15.0	PV	NVE	100%	100%	100%	
Nevada Solar One NPC	06/27/07	46.9	CSP	PPA	79%	79%	79%	a.
RV Apex Solar Power	07/21/12	20.0	PV	PPA	90%	90%	90%	a.
Sierra Solar (10%)	04/01/27	40.0	PV	NVE	n/a	n/a	100%	b.
Silver State Solar North	04/25/12	52.0	PV	PPA	91%	91%	91%	a.
Switch Station I	08/08/17	100.0	PV	PPA	87%	88%	88%	d.
Techren 1	03/11/19	100.0	PV	PPA	72%	72%	73%	a.
Techren 3	10/07/20	25.0	PV	PPA	85%	86%	86%	a.
Techren 5	12/31/20	50.0	PV	PPA	90%	90%	91%	a.
Apex Landfill	03/01/12	12.0	LFG	PPA	48%	48%	48%	a.
WMNRE Lockwood	04/01/12	3.2	LFG	PPA	94%	94%	94%	a.
Goodsprings	12/01/10	5.0	Waste Heat	NVE	100%	100%	100%	
Spring Valley Wind	08/16/12	151.8	Wind	PPA	90%	90%	90%	a.
		3,584.1						

a. Adjustment applied to the supply table or calculated supply table (if no PPA supply table) based on recent (2 or more years of performance) to determine the expected amount of energy generated by the facility to serve customer load. 100% equals no adjustment

b. The energy and PCs from these projects will be pooled then split between NPC and SPPC (ref. Docket No 19-06039)

c. 40 percent of PCs generated by this project are assigned to Sierra based on the order (Docket No. 19-06039)

d. The energy is delivered to Nevada Power to serve customer load, but the derived PCs are assigned to a customer and cannot be counted towards the RPS

After applying the above supply adjustments, this planning approach resulted in an average 2.37 percent decrease in the total amount of projected net renewable energy for the 2025 to 2027 action plan period as compared to the PPA supply tables assuming no adjustments. The estimated amount of renewable energy available to Nevada Power is shown in Figure ESP-10 below.

FIGURE ESP-10
NEVADA POWER PORTFOLIO CREDIT PROJECTIONS (kPCs)[1]

Nevada Power Company

		Action Period	
	2025	2026	2027
Credit Requirement			
Nevada RPS Credit Target [2.]	7,567,435	10,087,184	10,703,127
Other non-RPS Credit Obligations (NGR, 704B, etc.) [3.]	1,195,547	1,223,146	1,348,242
	8,762,982	11,310,330	12,051,369
Expected Credits all Sources - Unadjusted			
Energy / MW hrs [4.]	8,136,806	8,991,942	10,597,401
Station Usage, PC only, Co Owned, & Credit Allocations [5.]	(393,827)	(451,148)	(532,519)
RenewableGenerations [7.]	602,454	597,939	593,457
Carried Forward [8.]	2,444,550	2,027,000	(144,598)
Expected Credits, kPCs (All Sources, Unadjusted)	10,789,983	11,165,732	10,513,740
Projected Credit Surplus/<Deficit>	2,027,000	(144,598)	(1,537,629)
Expected Credits all Sources - Adjusted			
Energy / MW hrs [9.]	7,909,557	8,775,010	10,372,059
Station Usage, PC only, Co Owned, & Credit Allocations [5.]	(393,827)	(451,148)	(532,519)
RenewableGenerations [7.]	602,454	597,939	593,457
Carried Forward [8.]	2,444,550	1,799,751	(588,780)
Expected Credits, kPCs (All Sources, adjusted)	10,562,733	10,721,551	9,844,217
Projected Credit Surplus/<Deficit> w/Adj.	1,799,751	(588,780)	(2,207,152)

1 1 kWh = 1 PC, 1,000 kWh (1 MWh) = 1 kPC
2 Nevada RPS credit target by year 34%, 2024-2026, 42% 2027
3 Non-RPS credit obligations: Nevada GreenRider (NGR), Energy Supply Agreements (ESA) and Exit Obligations (704B)
4 Total renewable energy delivered to Nevada Power's system and available to meet Nevada Power's retail load
5 Credits from station usage, small NVE owned systems, credit only agreements, settlement agreements, Gemini credits allocated to Sierra and credits assigned to NGR Customers
6 DSM credits are limited to 10% 2024, zero post 2024
7 Credits incentive programs pursuant to NRS Chapter 701B
8 Excess credits carried forward for future compliance (note the plan assumes no excess credit sales)
9 Adjusted energy supply outlook after adjusting for historical performance

Figure ESP-11 below is a summary of all projects and supply adjustments used in developing Sierra's RPS outlook. Note, the list below only includes projects that were approved by the Commission as of June 30, 2025.

FIGURE ESP-11
SIERRA'S SHORT-TERM SUPPLY ADJUSTMENTS

Facility	Actual / Projected COD	NamePlate (AC)	Resouce	Type	2025 [a]	2026 [a]	2027 [a]	2028 [a]	
					IRP/ESP Action Period				
Richard Burdette	02/28/06	26.0	Geo	PPA	100%	100%	100%	100%	
Galena 3	02/21/08	26.5	Geo	PPA	100%	100%	100%	100%	
North Valley Geo	04/26/23	25.0	Geo	PPA	100%	100%	100%	100%	
USG San Emidio	05/25/12	11.8	Geo	PPA	100%	100%	100%	100%	
Battle Mountain	06/23/21	101.0	PV	PPA	100%	100%	100%	100%	
Dodge Flat	03/02/22	200.0	PV	PPA	100%	100%	100%	100%	
Fish Springs Ranch	03/15/22	100.0	PV	PPA	100%	100%	100%	100%	
Nevada Solar One SPPC	06/27/07	22.1	CPS	PPA	79%	79%	79%	n/a	a.
Arrowhead Canyon (Moapa) Solar (70%	12/01/22	140.0	PV	PPA	100%	100%	100%	100%	b.
Ft. Churchill PV	08/05/15	19.5	PV	PPA	100%	100%	100%	100%	
Boulder Solar II Apple	01/27/17	50.0	PV	PPA	94%	94%	94%	94%	a.
Sierra Solar (90%)	04/01/27	360.0	PV	NVE	n/a	n/a	100%	100%	b.
Switch Station 2	10/11/17	51.3	PV	PPA	91%	91%	91%	92%	c.
Techren Solar II	10/04/19	200.0	PV	PPA	100%	100%	100%	100%	
Techren Solar IV	10/07/20	25.0	PV	PPA	85%	85%	85%	85%	a.
Turquoise	12/04/20	50.0	PV	PPA	100%	100%	100%	100%	
Frank Hooper	06/23/86	0.8	Hydro	PPA	100%	100%	100%	100%	
TMWA Fleish	05/16/08	2.3	Hydro	PPA	121%	121%	121%	121%	a.
TMWA Verdi	05/15/09	2.2	Hydro	PPA	125%	125%	125%	125%	a.
TMWA Washoe	07/25/08	2.2	Hydro	PPA	231%	231%	231%	175%	a.
Ormat Portfolio:									
> Beowawe Bundled	01/01/25	20.0	Geo	PPA	105%	105%	110%	100%	
> Desert Peak 2 Bundled	02/07/28	10.0	Geo	PPA	100%	n/a	n/a	n/a	
> Galena 1 Bundled	02/01/27	15.0	Geo	PPA	100%	n/a	n/a	n/a	
> Galena 3 Bundled	01/01/29	15.0	Geo	PPA	100%	n/a	n/a	n/a	
> Gerlach Bundled	01/01/28	15.0	Geo	PPA	100%	n/a	n/a	n/a	
> North Valley 2 Bundled	01/01/26	15.0	Geo	PPA	100%	n/a	n/a	n/a	
> Lone Mountain Bundled	10/01/28	15.0	Geo	PPA	100%	n/a	n/a	n/a	
> Pinto Bundled	01/01/27	15.0	Geo	PPA	100%	n/a	n/a	n/a	
		1,535.6							

a. Adjustment applied to the supply table or calculated supply table (if no PPA supply table) based on recent (2 or more years of performance) to determine the expected amount of energy generated by the facility to serve customer load. 100% equals no adjustment

b. The energy and PCs from these projects will be pooled then split between NPC and SPPC (ref. Docket No 19-06039)

c. The energy is delivered to Nevada Power to serve customer load, but the derived PCs are assigned to a customer and cannot be counted towards the RPS

d. The project will reach full capacity in phases

After applying the above supply adjustments, this planning approach resulted in an average 0.66 percent decrease in the total amount of projected net renewable energy for the 2025 to 2027 action plan period as compared to the PPA supply tables assuming no adjustments. The estimated amount of renewable energy available to Sierra in this year's ESP is shown in Figure ESP-12 below.

FIGURE ESP-12
SIERRA PORTFOLIO CREDIT PROJECTIONS (kPCs)[1]

Sierra Pacific Power

		Action Period	
	2025	2026	2027
Credit Requirement			
Nevada RPS Credit Target [2.]	3,390,209	5,292,741	6,744,853
Other non-RPS Credit Obligations (NGR, 704B, etc.) [3.]	1,054,992	980,877	961,093
	4,445,201	6,273,618	7,705,946
Expected Credits all Sources - Unadjusted			
Energy / MW hrs [4.]	3,392,264	4,382,170	4,714,668
Station Usage, PC only, Co Owned, & Credit Allocations [5.]	665,970	696,157	800,715
RenewableGenerations [7.]	110,485	109,659	108,839
Carried Forword [8.]	1,242,674	966,192	(119,439)
Expected Credits, kPCs (All Sources, Unadjusted)	5,411,393	6,154,179	5,504,783
Projected Credit Surplus/<Deficit>	966,192	(119,439)	(2,201,162)
Expected Credits all Sources - Adjusted			
Energy / MW hrs [9.]	3,358,332	4,349,852	4,683,954
Station Usage, PC only, Co Owned, & Credit Allocations [5.]	665,970	696,157	800,715
RenewableGenerations [7.]	110,485	109,659	108,839
Carried Forward [8.]	1,242,674	932,261	(185,689)
Expected Credits, kPCs (All Sources, adjusted)	5,377,462	6,087,929	5,407,820
Projected Credit Surplus/<Deficit> w/Adj.	932,261	(185,689)	(2,298,126)

1 1 kWh = 1 PC, 1,000 kWh (1 MWh) = 1 kPC
2 Nevada RPS credit target by year 34%, 2024-2026, 42% 2027
3 Non-RPS credit obligations: Nevada GreenRider (NGR), Energy Supply Agreements (ESA) and Exit Obligations (704B)
4 Total renewable energy delivered to Sierra's system and available to meet Sierra's retail load
5 Credits from station usage, small NVE owned systems, credit only agreements, settlement agreements, Gemini credits allocated to Sierra and credits assigned to NGR Customers
6 DSM credits are limited to 10% 2024, zero post 2024
7 Credits incentive programs pursuant to NRS Chapter 701B
8 Excess credits carried forward for future compliance (note the plan assumes no excess credit sales)
9 Adjusted energy supply outlook after adjusting for historical performance

Compliance Outlook

NEVADA POWER

Nevada Power's RPS compliance outlook is forecasted to be non-compliant in 2027. The limited available land for development, multiyear project permitting timelines, and lack of available transmission capacity are key constraints in the renewable project pipeline. The completion of costly requisite network upgrades, procurement of long-lead critical equipment such as breakers and transformers, as well as project permit issuance and transmission interconnectivity capability, are interdependent project milestones that are subject to various independent external forces that cannot be easily mitigated, even with diligent planning. Nevada Power's renewable project pipeline therefore carries some amount of inherent risk, as most recently demonstrated by the termination of the first Boulder Solar III PPA previously approved in Docket No. 20-07023. In addition, the Nevada Power Owned Community Solar and Solar For All projects proposed in Docket No. 24-05041 were not approved, resulting in the loss of a planned 56,163 PCs. To this end, Nevada Power will continue to explore all options, including continuing to issue renewable energy RFPs, self-developing projects, conducting bilateral asset purchases and other commercial transactions and exploring short-term purchase agreements that benefit customers, so that it can procure the renewable generating and storage resources needed to continue meeting its RPS commitments. Nevada Power's challenge is to make certain that it has sufficient renewable resources, existing and pipeline, to satisfy all credit and energy needs for at the years through 2027 and beyond.

<u>SIERRA</u>

Sierra's RPS compliance outlook is forecasted to be non-compliant in 2027. This is different from 2024's outlook for several reasons. The first and primary reason is increased projected load growth. Sierra's current retail load outlook as described previously is significantly higher than that of the previous approved plan from the 2024 IRP. Referring to Figure ESP-13a under the updated load forecast, while Nevada Power's projected retail sales are projected to increase slightly, Sierra's projected retail sales are projected to increase significantly. Because the RPS credit requirement is tied directly to retail sales, this dramatically increases Sierra's forecasted RPS credit requirement. Included in the increased forecast of Sierra's load is the planned extension of the Liberty contract through May 31, 2027, which also provides PCs to the utility. Finally, the Sierra Utility Owned Community Solar and Solar for all projects proposed in Docket No. 24-05041 were not approved, resulting in the loss of a planned 6,312 PCs.

FIGURE ESP-13a

	Sierra (MW hours)			NPC (MW Hours)		
	2024 IRP	2025 ESP Update	Difference	2024 IRP	2025 ESP Update	Difference
2025	9,596,795	9,009,892	-6.12%	21,963,555	21,136,509	-3.77%
2026	9,851,290	9,971,202	1.22%	22,173,512	22,257,162	0.38%
2027	10,123,938	12,601,765	24.47%	22,371,526	24,017,105	7.36%
2028	10,395,713	16,059,174	54.48%	22,633,211	25,493,637	12.64%
2029	10,602,683	19,216,823	81.24%	22,874,396	27,234,474	19.06%
2030	10,680,569	21,083,099	97.40%	23,043,445	28,523,493	23.78%

	Increase/ (Decrease)	RPS%	Credit Impact	Increase/ (Decrease)	RPS%	Credit Impact
2025	-586,903	34.0%	-199,547	-827,046	34.0%	-281,196
2026	119,912	34.0%	40,770	83,650	34.0%	28,441
2027	2,477,827	42.0%	1,040,687	1,645,579	42.0%	691,143
2028	5,663,461	42.0%	2,378,654	2,860,426	42.0%	1,201,379
2029	8,614,140	42.0%	3,617,939	4,360,078	42.0%	1,831,233
2030	10,402,530	50.0%	5,201,265	5,480,048	50.0%	2,740,024

Docket No. 24-05041 Sales Forecast

The second reason for Sierra's uncertain compliance is cancelled projects by developers. Figure ESP-13b below shows the PCs Sierra has recently lost due to canceled projects. Ormat has provided notice to the Companies that two of its portfolio projects, North Valley 2 and Gerlach, have been cancelled, and the Lone Mountain project COD has been delayed from January 2026 to October 2028. Additionally, Liberty Utilities has notified the Companies that it has placed the Luning Expansion project on hold indefinitely, which would have provided Liberty with PCs and therefore reduced Sierra's PC transfer obligation to Liberty under the requirements of the Service Agreement. The energy and credits from these facilities were to be assigned to Sierra, thus, the loss impacts Sierra's RPS compliance and capacity. While Nevada Power was hit by the same wave of canceled projects, it did not face the same degree of projected sales growth. While every project is entered into with the expectation of success, events can and do happen that make once-viable projects unviable. The primary driver for the latest wave of cancelations was cost. Most of the canceled projects were negotiated pre-COVID, and the supply disruptions and related increases in component and labor costs made the projects too costly to move forward.

FIGURE ESP-13b

Lost Projects, Lost Generation

Projects [a]	Docket No.	Original COD	Date Terminated	MW AC	2024	2025	2026	2027
Iron Point (44% SPPC)	21-06001	12/31/23	06/22/23	250	313,240	311,244	309,949	308,652
Hot Pot (44% SPPC)	21-06001	12/01/24	06/22/23	350	18,368	440,048	438,440	436,610
Southern Bighorn (40% SPPC)	19-06039	09/01/23	11/13/23	300	406,619	404,267	403,025	401,783
North Valmy Eavor Loop	22-11032	12/31/26	06/22/24	20	0	15,246	92,223	173,039
North Valley II (OWGP)	22-11032	01/01/26	04/25/25	15	0	0	150,921	150,921
Gerlach (OWGP)	22-11032	01/01/28	04/25/25	15	0	0	150,921	150,921
Lone Mountain (OWGP)	22-11032	01/01/26	04/29/25 [b]	15	0	0	131,221	131,221
				950	740,251	1,172,830	1,547,504	1,623,953

Table Notes:

a. The energy/credits of the project as allocated between Nevada Power and Sierra per the order

b. The Lone Mountain project has been delayed until 01/01/2028, not cancelled. The date shown reflects when NV Energy was notified of the delay. The Companies are still in discussion s with the counterparty to explore all remedial options.

A third contributing factor to Sierra's uncertain RPS compliance outlook is transmission constraints for Sierra. Currently there is limited ability to move energy from generation to load in Sierra' service territory in the near term, requiring completion of contingent facilities and significant additional transmission infrastructure to remedy. The completion of Greenlink West and Greenlink North will allow for a significant addition of renewable energy capacity in Sierra's territory when it goes into service. It is the combination of the three factors that changed Sierra's outlook from uncertain to forecasted non-compliance in 2027.

To mitigate risk on non-compliance, Sierra will continue to explore all near-term options, including evaluating available proposals received from renewable energy RFPs, self-developing projects, discussions with counterparties to amend existing PPAs to facilitate acquisition of additional PCs, conducting bilateral asset purchase and other commercial transactions and exploring short-term purchase agreements that benefit customers, so that it can procure the renewable generating and storage resources needed to continue meeting its RPS requirement.

Nevada Power and Sierra will continue to closely monitor their RPS compliance outlooks, recognizing that there are many factors, some outside of the Companies' control, which will ultimately determine whether the Companies will have a sufficient number of PCs to satisfy their respective RPS credit obligations.

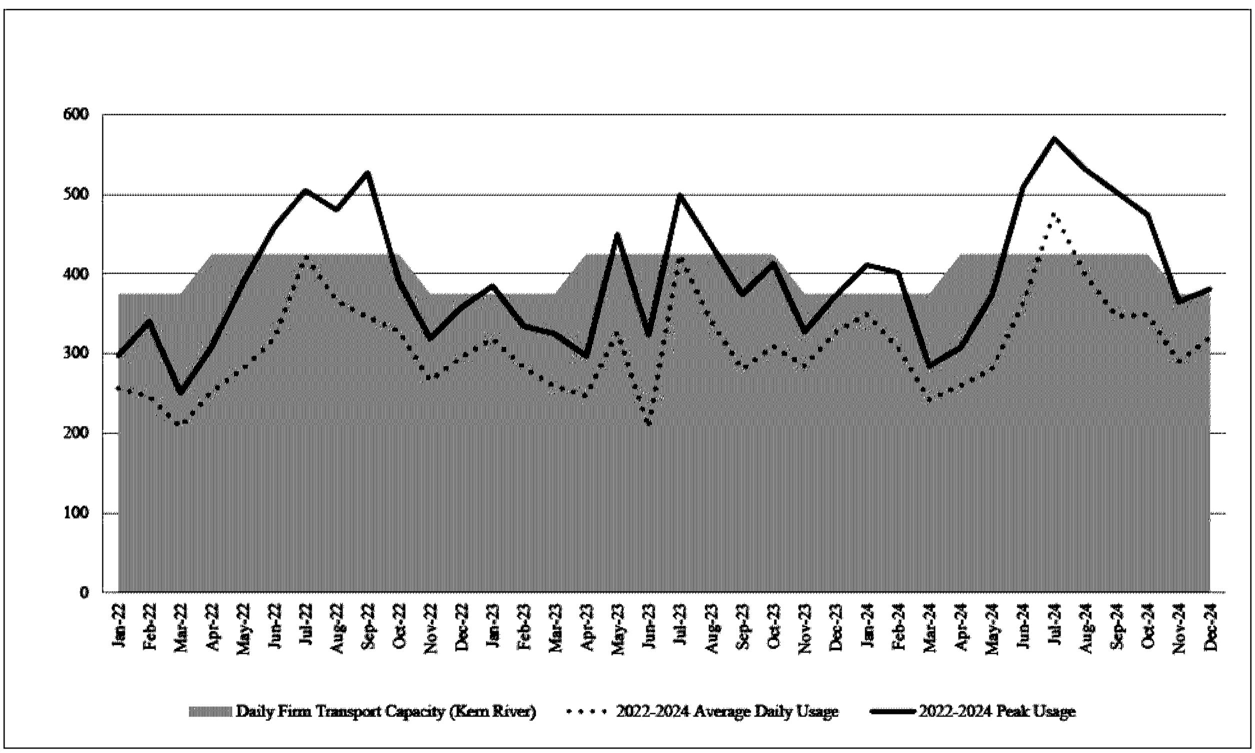
E. GAS TRANSPORTATION REQUIREMENTS

The Companies' portfolio of gas transportation assets serves their generation units and Sierra's local distribution company ("LDC"). The existing firm gas transportation assets for Nevada Power and Sierra are listed in Figures ESP-39 and ESP-40 respectively. The Companies rely on rights of first refusal and annual evergreen rights to keep existing gas transport capacity rights in place. As of the date of this filing, the Companies have not added to their existing gas transport portfolio. Sierra, however, will soon be adding transportation capacity from Ruby Pipeline ("Ruby") and Pinyon Pipeline ("Pinyon") which will supply natural gas to the Valmy Plant. The Valmy Plant is being converted to operate on natural gas.

For the ESP, the Companies utilized PLEXOS, a chronological unit commitment and economic dispatch model, to evaluate the system reliability and projected firm gas transportation needs for Nevada Power and Sierra generating plants and the LDC with the One Nevada Transmission Line ("ON Line") in service.

For the previous three years, Nevada Power's firm transportation capacity was fully utilized 28 days in 2022, 24 days in 2023, and 72 days in 2024 leaving open positions for firm interstate gas transportation in each year, as seen in Figure ESP-14.

FIGURE ESP-14
NATURAL GAS USAGE VS. TRANSPORT CAPACITY (000s MMBTU/DAY)
NEVADA POWER



Historically, Nevada Power's firm interstate gas transportation open positions have been reliably met by purchasing firm delivered gas.

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 2026 through December 2027.

Two scenarios were evaluated:

1. Normal weather conditions and existing firm gas transportation contracts; and
2. Hot summer/cold winter weather conditions[10] (based on 1 in 10 peak Cooling Degree Days ("CDD") and Heating Degree Days ("HDD")) and existing firm gas transportation contracts.

Based on this modeling, the projected number of days Nevada Power will require deliveries in excess of the existing firm rights for natural gas transportation capacity under normal weather conditions are 76 days for 2026, and 150 for 2027. Similarly, under hot summer/cold winter weather conditions, the projected number of days Nevada Power will require deliveries in excess of the existing firm rights for natural gas transportation capacity are 214 days for 2026, and 251 for 2027. Figure ESP-15 and Figure ESP-16 show the projected daily natural gas requirements at Nevada Power with the firm natural gas transportation available for both the normal and hot summer/cold winter weather scenarios for the generation fleet.

[10] See Technical Appendix LF-1, Section VIII – Weather Scenario Forecast for Gas Transportation Analysis, provided in support of the Third Amendment and approved in the March 24, 2023, Order in Docket No. 22-09006, for more details.

FIGURE ESP-15
NORMAL WEATHER NATURAL GAS USAGE VS. TRANSPORT CAPACITY
(MMBTU/DAY)
NEVADA POWER

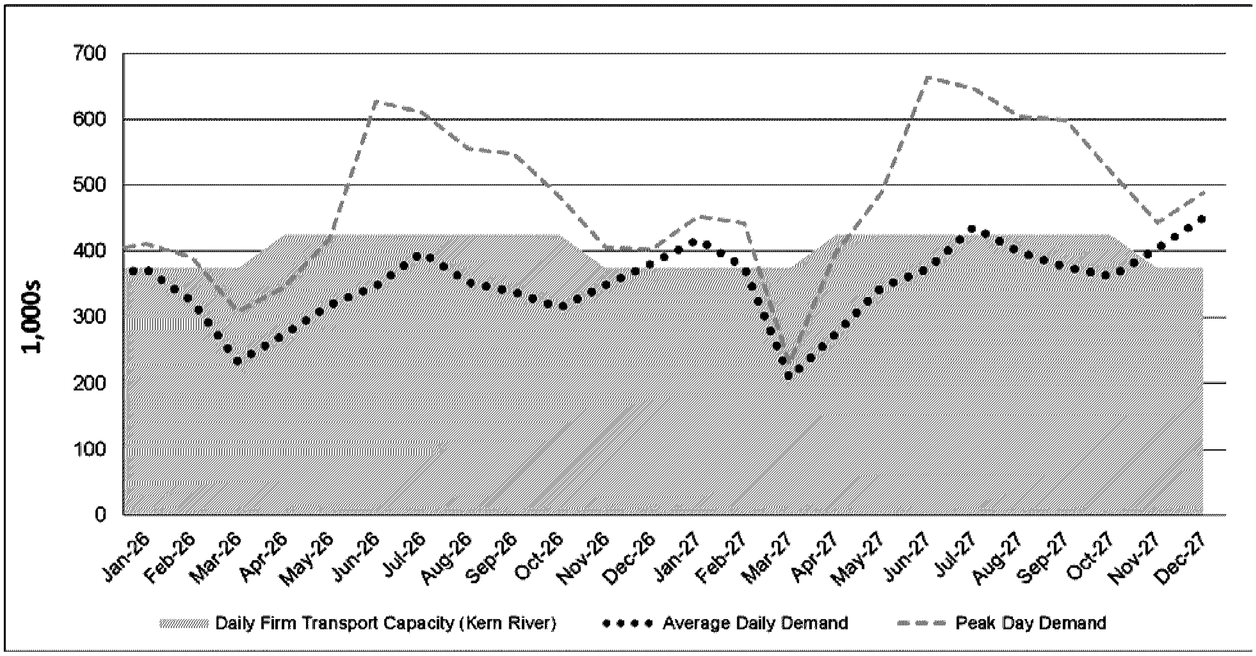
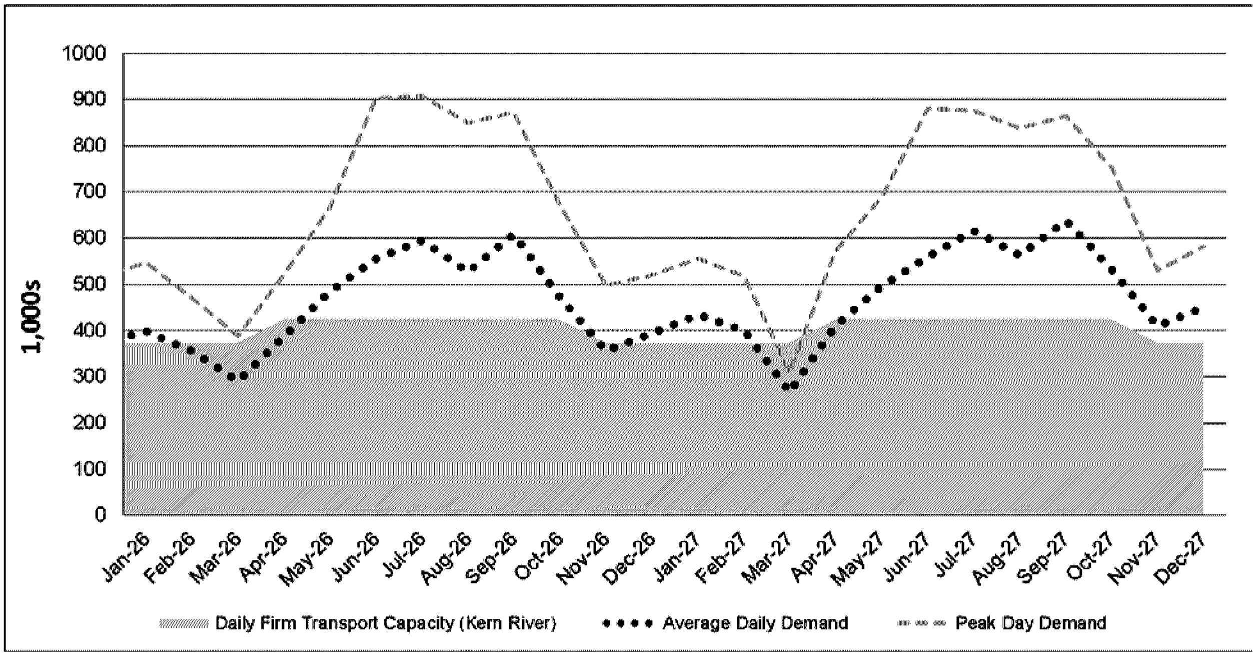


FIGURE ESP-16
HOT SUMMER/COLD WINTER WEATHER - NATURAL GAS USAGE VS. TRANSPORT CAPACITY (MMBTU/DAY)
NEVADA POWER



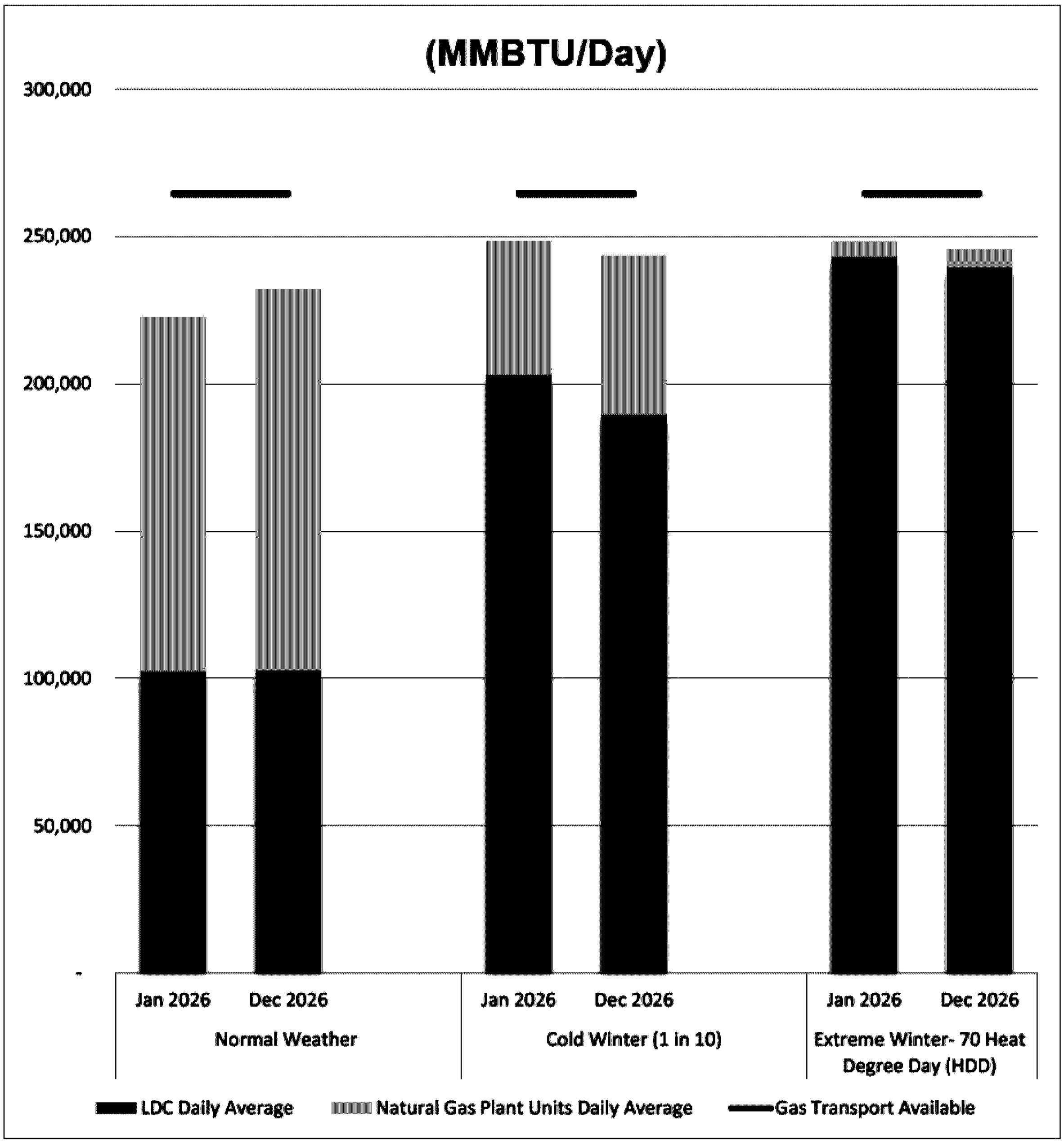
PLEXOS was used to evaluate Sierra's system reliability and projected firm gas transportation needs for both the plants and LDC with ON Line in service. PLEXOS was used to estimate electric system reliability, as quantified by LOLH for both Nevada Power and Sierra, with the latter combining electric 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 2026-2027), as the LDC's recorded peaks have predominantly occurred in those two months. Three scenarios were evaluated:

1. Normal weather conditions and existing natural gas transportation contracts.
2. Cold winter weather conditions (based on 1 in 10 peak HDD) and existing natural gas transportation contracts.
3. Extreme weather conditions (based on 70 HDDs) and existing natural gas transportation contracts.

Figure ESP-17 shows the daily natural gas requirements projected for December/January along with the firm natural gas transportation available for the three scenarios for both the LDC and electric generating plants.

FIGURE ESP-17
SIERRA DAILY NATURAL GAS REQUIREMENT
FOR DECEMBER/JANUARY



The key finding from this analysis is that Sierra has sufficient 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. However, during a cold winter (1 in 10) or extreme winter weather scenario, Sierra's firm gas transport capacity is heavily utilized, approximately 77 percent and 92 percent, respectively, to meet LDC peak day requirements, limiting availability of Sierra's natural gas-fired generation plants. In the extreme weather case, the majority of the electric requirements would need to be met with a combination of purchased power, renewable energy, and inter-company exchange from the southern system. It is noteworthy that the repowered natural gas fired Valmy power plants, because of their location, do not compete for natural gas with Sierra's local gas distribution system. However, in the extreme weather case, the analysis shows LOLH was observed on the Sierra electric system in most hours of the two months of each year studied.

Historically, on a combined basis (LDC plus natural gas for Sierra's electric generation), Sierra is long on natural gas transportation capacity in the months of March through November but close to capacity in the months of December through February during normal weather conditions. Given the high peak day LDC forecast for both the 1 in 10 and extreme winter scenarios, Sierra will assess the need to increase firm interstate gas transportation.

Nevada Power and Sierra will continue to evaluate opportunities to release capacity during the months in which capacity is greater than projected requirements based on economics and reliability. The Companies will continue to purchase firm delivered gas to reliably meet open positions with respect to firm interstate gas transportation.

F. PHYSICAL GAS REQUIREMENTS

The Companies used PLEXOS to calculate the average daily gas requirements as illustrated in Figures ESP-18 and ESP-19.

FIGURE ESP-18
NEVADA POWER AVERAGE DAILY GAS REQUIREMENTS

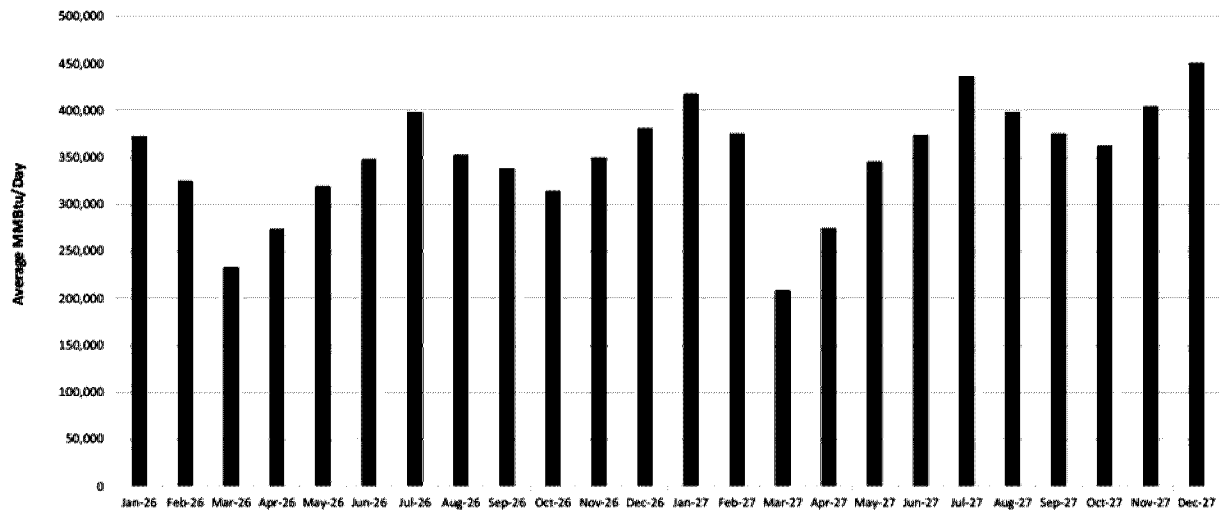
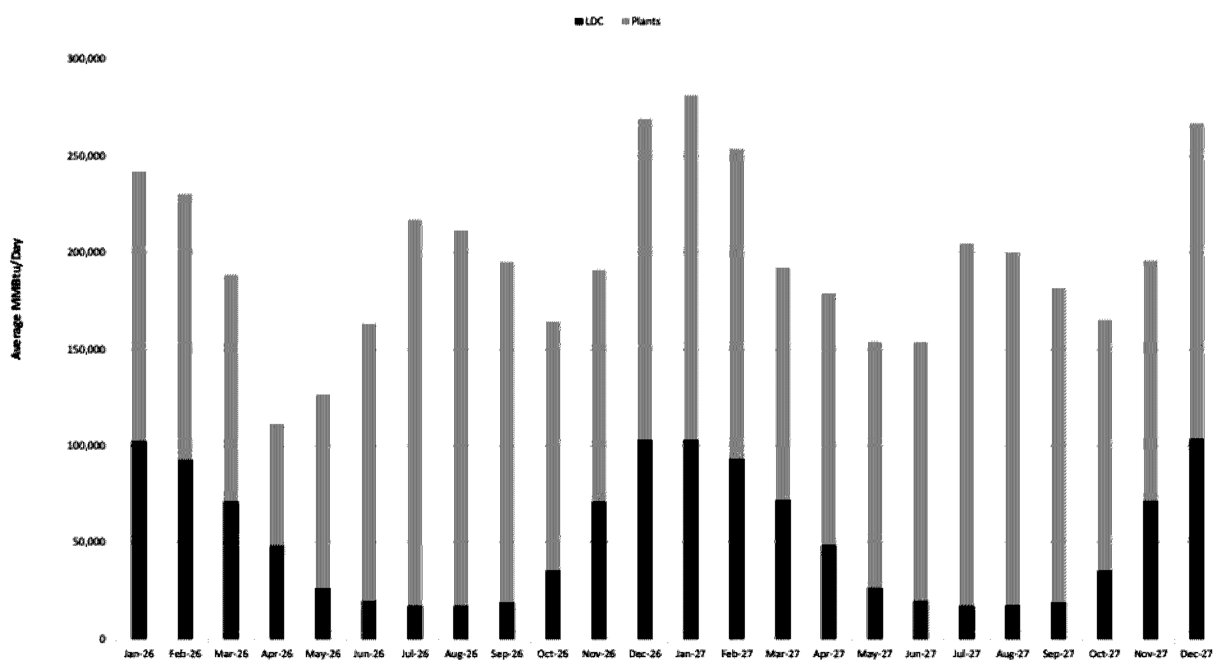


FIGURE ESP-19
SIERRA AVERAGE DAILY GAS REQUIREMENTS



The Companies employ a four-season laddering strategy for physical gas purchases through which 25 percent of projected monthly gas requirements per season is procured, subject to the availability of conforming bids and the willingness of suppliers to accept reasonable commercial terms. Figure ESP-20 shows the current approved physical gas volumes and future targets for the Companies.

FIGURE ESP-20
PHYSICAL GAS SUPPLY UNDER CONTRACT (MMBTU/DAY)

Monthly NPC	Current Approved Volumes	Volumes Procured as of 8/1/2025	Current Target Procurement Level	Estimated Volumes to Be Procured in 2025 Q3 RFP	Estimated Total Volumes Procured After 2025 Q3 RFP	Estimated Pct of Approved Volumes Closed Following 2025 Q3 RFP
Jan-2026	381,000	285,500	75%	95,500	381,000	100%
Feb-2026	344,000	258,000	75%	86,000	344,000	100%
Mar-2026	287,000	215,500	75%	71,500	287,000	100%
Apr-2026	301,000	150,500	50%	75,000	225,500	75%
May-2026	357,000	178,000	50%	90,000	268,000	75%
Jun-2026	375,000	187,000	50%	94,000	281,000	75%
Jul-2026	410,000	205,000	50%	103,000	308,000	75%
Aug-2026	369,000	184,500	50%	92,000	276,500	75%
Sep-2026	348,000	173,500	50%	88,000	261,500	75%
Oct-2026	330,000	165,000	50%	83,000	248,000	75%
Nov-2026	349,000	87,000	25%	88,000	175,000	50%
Dec-2026	394,000	98,000	25%	99,000	197,000	50%
Jan-2027	386,000	96,500	25%	97,000	193,500	50%
Feb-2027	340,000	85,000	25%	85,000	170,000	50%
Mar-2027	275,000	68,500	25%	69,000	137,500	50%

Monthly SPPC	Current Approved Volumes	Volumes Procured as of 8/1/2025	Current Target Procurement Level	Estimated Volumes to Be Procured in 2025 Q3 RFP	Estimated Total Volumes Procured After 2025 Q3 RFP	Estimated Pct of Approved Volumes Closed Following 2025 Q3 RFP
Jan-2026	213,000	159,000	75%	54,000	213,000	100%
Feb-2026	180,000	135,000	75%	45,000	180,000	100%
Mar-2026	143,000	107,000	75%	36,000	143,000	100%
Apr-2026	119,000	59,000	50%	30,000	89,000	75%
May-2026	113,000	56,500	50%	28,000	84,500	75%
Jun-2026	140,000	69,500	50%	36,000	105,500	75%
Jul-2026	194,000	97,000	50%	49,000	146,000	75%
Aug-2026	183,000	91,000	50%	46,000	137,000	75%
Sep-2026	163,000	81,000	50%	41,000	122,000	75%
Oct-2026	142,000	70,500	50%	36,000	106,500	75%
Nov-2026	179,000	44,500	25%	45,000	89,500	50%
Dec-2026	238,000	59,500	25%	60,000	119,500	50%
Jan-2027	225,000	56,000	25%	57,000	113,000	50%
Feb-2027	200,000	50,000	25%	50,000	100,000	50%
Mar-2027	176,000	43,500	25%	45,000	88,500	50%

The natural gas volumes shown in Figure ESP-20 are subject to the following explanations:

- Procured volumes in the table above do not include an adjustment for pipeline retainage or losses. To account for pipeline retainage or losses, the actual volume procured must be greater than the volume that will be delivered at the burner tip. As a point of reference, the NWPL system is estimated to have a two percent fuel retainage factor. This means that for every 1,000 MMBtu burned at the burner tip, there must be 1,020 MMBtu entering the pipeline from its various gas supply basins. The Companies procure amounts necessary to address pipeline retainage factors as part of their daily balancing and portfolio optimization activities.

- The volumes offered by bidders cannot be precisely matched to the procurement targets for each month. Therefore, the total volume of the transacted bid responses may deviate from a specific month's target volume. Specific gas transactions were entered into after all gas supply offers were input into an internally developed linear programming optimization model that sought to minimize costs subject to constraints, such as credit and incremental pipeline delivery charges. The aforementioned model calculates the lowest total gas supply portfolio cost.

- The Companies avoid acquiring volumes of less than 1,000 MMBtu per day because such purchases typically carry "odd lot size" premiums.

- All gas quantities will be delivered to Nevada Power via Kern River and to Sierra via Great Basin, Tuscarora and Ruby, subject to meeting any gas transport contractual obligations, such as operational flow orders issued by upstream and/or downstream pipelines.

G. FINANCIAL GAS REQUIREMENTS

The Companies are not proposing to acquire financial hedges during the ESP action period. This proposal is outlined in Section 5.C.

H. COAL REQUIREMENTS

For more information on Valmy operation, please see Section 6.

SECTION 3 - MARKET FUNDAMENTALS & PRICE FORECASTS

A. MARKET FUNDAMENTALS

1. ELECTRICITY

Regional Profile. The Companies are members of the Western Electricity Coordinating Council ("WECC"). WECC is the Regional Entity ("RE") responsible for compliance monitoring and enforcement and oversees reliability planning and assessments. In addition, WECC provides an environment for the development of Reliability Standards and the coordination of the operating and planning activities of its members as set forth in the WECC bylaws. There are six REs given authority by the North American Electric Reliability Corporation ("NERC") and the Federal Energy Regulatory Commission ("FERC"). Of those six entities, WECC oversees the largest and most geographically diverse region, known as the Western Interconnection ("WI"). WECC's footprint extends from Canada to Mexico and includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between.[11] Figure ESP-21 depicts the various NERC regions and sub-regions, including the WECC. This level of granularity allows NERC to better evaluate resource adequacy and ensure deliverability constraints between and among assessment areas are accounted for.

The WECC assessment area is divided into five sub-regions: California/Mexico ("CA/MX"), Northwest ("NW"), Alberta ("AB"), British Columbia ("BC"), and the Southwest ("SW"). NW area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota. The Companies reside in the NW sub-region. These subregional divisions are used for this assessment as they are structured around reserve sharing groups that have similar annual demand patterns and similar operating practices.

[11] https://www.wecc.org/Pages/AboutWECC.aspx

FIGURE ESP-21
NERC REGIONS AND SUB-REGIONS

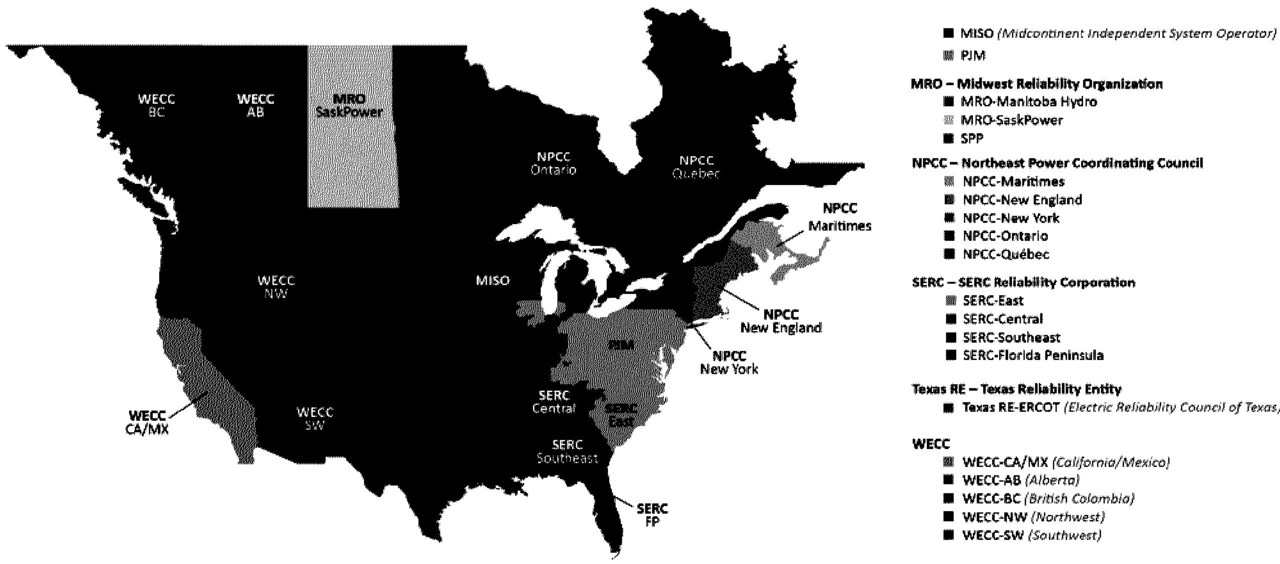


Figure ESP-22 shows the capacity composition in the NW (Northwest) sub-region and the prevalence of gas-fired and hydroelectric generation.[12]

FIGURE ESP-22
WECC-NW CAPACITY BY FUEL TYPE

WECC-NW Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	14,965	11,031	11,021	9,667	8,761
Coal*	14,661	10,223	10,607	9,349	8,060
Petroleum	321	321	319	319	316
Natural Gas	33,452	33,636	33,304	32,954	32,749
Biomass	729	723	683	683	604
Solar	9,086	10,191	9,350	9,431	10,379
Wind	3,924	4,566	4,939	4,939	4,561
Geothermal	884	934	933	1,007	997
Conventional Hydro	21,003	21,000	21,542	21,522	20,958
Pumped Storage	373	373	375	375	373
Nuclear	1,096	1,096	1,096	1,096	1,096
Other	64	64	64	64	64
Battery	2,084	2,219	2,188	2,188	2,219
Total MW	87,981	86,154	85,814	84,245	83,077
Total MW*	87,679	85,346	85,398	83,926	82,377
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

[12] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf

Energy Imbalance Market ("EIM").

The California Independent System Operator's ("CAISO") EIM is a real-time energy market, the first of its kind in the western United States. The EIM's advanced market system automatically finds low-cost energy to serve real-time consumer demand across the West. Since its launch, the EIM has enhanced grid reliability and generated cost savings for its participants. In addition to its economic advantages, the EIM improves the integration of renewable energy, leading to a cleaner, "greener" grid.[13] The EIM began financially binding operation on November 1, 2014, by optimizing resources across the CAISO and PacifiCorp Balancing Authority Areas ("BAAs"). NV Energy began participating in December 2015. The EIM uses a sophisticated system to automatically balance demand every five minutes with the lowest cost energy available across the combined grid.

The first quarter 2025 EIM Benefits Report published by the CAISO estimates that the EIM has yielded more than $6.99 billion in total benefits for all participants since the market was launched in 2014. The measured benefits of participation in the EIM include cost savings, increased integration of renewable energy, and improved operational efficiencies including the reduction of the need for real-time flexible reserves. The estimated gross economic benefits for the Companies have been $81.71 million out of total $744.05 million in the first quarter of 2025.[14] Sharing resources across a larger geographic area reduces greenhouse gas emissions by utilizing renewable generation that otherwise would have been turned off. A map of the active and pending EIM participants is provided in Figure ESP-23.

Participants

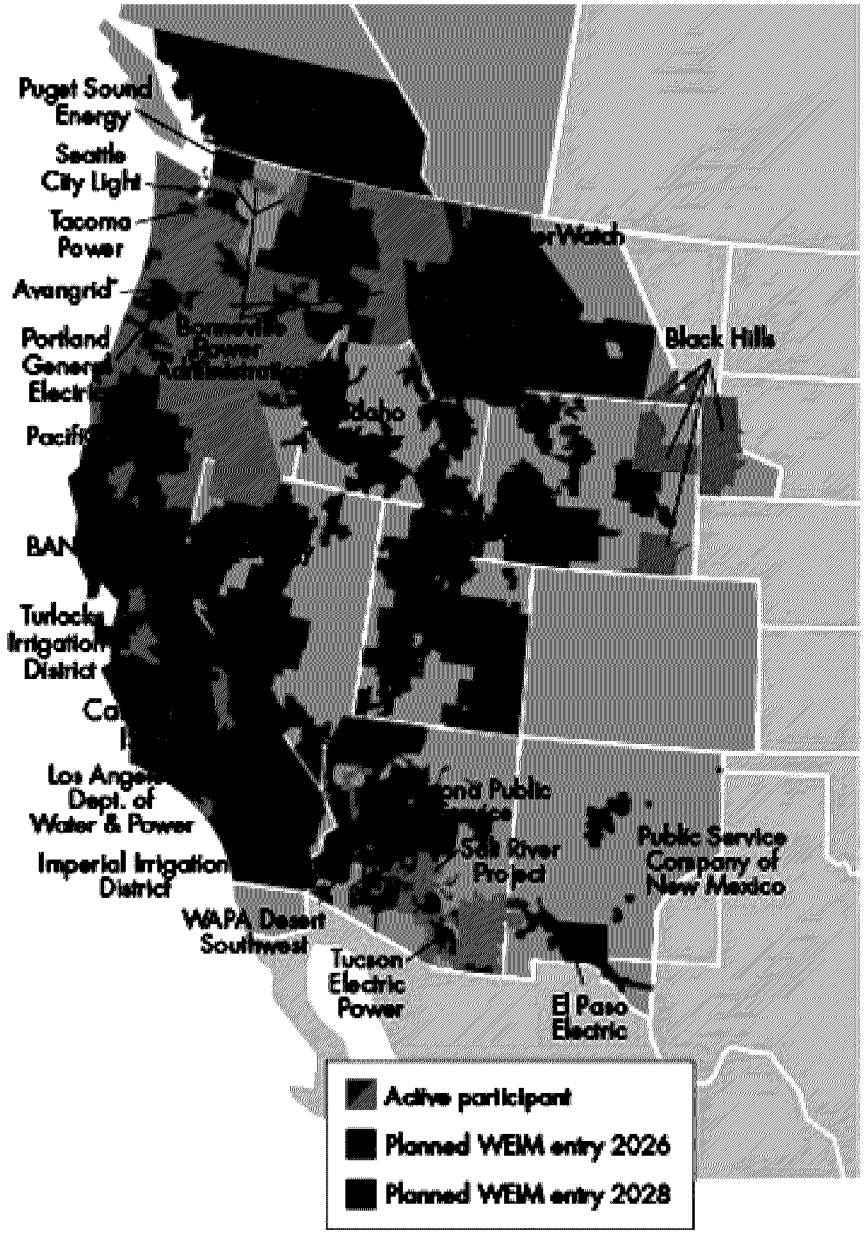
- Imperial Irrigation District – planned entry 2028
- Black Hills – planned entry 2026
- PowerWatch (formerly BHE Montana) – planned entry 2026
- Avangrid – entered 2023
- El Paso Electric – entered 2023
- WAPA Desert Southwest Region – entered 2023
- Bonneville Power Administration – entered 2022
- Tucson Electric Power – entered 2022
- Avista – entered 2022
- Tacoma Power – entered 2022
- NorthWestern Energy – entered 2021
- Los Angeles Department of Water & Power – entered 2021
- Public Service Company of New Mexico – entered 2021

[13] https://www.westerneim.com/Pages/About/default.aspx

[14] https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx

- Turlock Irrigation District – entered 2021
- Salt River Project – entered 2020
- Seattle City Light – entered 2020
- Balancing Authority of Northern California – entered 2019
- Idaho Power Company – entered 2018
- Powerex – entered 2018
- Portland General Electric – entered 2017
- Puget Sound – entered 2016
- Arizona Public Service – entered 2016
- NV Energy – entered 2015
- PacifiCorp – entered 2014
- California ISO – entered 2014

FIGURE ESP-23
WESTERN EIM ACTIVE PARTICIPANTS



**Avangrid office; generation only BAA with distribution across multiple states.*
Map boundaries are approximate and for illustrative purposes only.

Resource Adequacy

To ensure reliability during the transition to greater reliance on renewable resources, emerging resource and energy adequacy issues must be addressed. Planning for long-term resource adequacy is becoming increasingly complex with a resource mix that is more unpredictable and less energy assured. To evaluate the projected resource adequacy (generation resource reserve margins), NERC prepares the Long-Term Reliability Assessment ("LTRA") - an annual assessment of anticipated resource reserve margins.

Planning Reserve Margins (Anticipated Reserve Margin or "ARM" [15] and PRM [16]) are calculated and reported for each of the WECC sub-regions and provide an indication of the ability of those sub-regions to meet their load requirements with internal generation and imports from other sub-regions or zones under the specified conditions. Planning Reserve Margins (anticipated or prospective) are calculated by finding the difference between the amount of projected on-peak capacity and the forecasted peak demand and then dividing this difference by the forecasted peak demand.

NERC assesses resource adequacy by evaluating each assessment area's planning reserve margins relative to its Reference Margin Level [17] ("RML") - a "target" or requirement based on traditional capacity planning criteria. The projected resource capacity used in the evaluations is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the RML, which represents the desired level of risk based on a probability-based loss-of-load ("LOL") analysis.

The most recent forecast of these reserve margins from the NERC 2024 LTRA published in December of 2024 is shown in Figure ESP-24. [18]

[15] This is the amount of anticipated resources (includes only Tier 1 resources) less net internal demand calculated as a percentage of net internal demand.

[16] This is the amount of prospective resources (includes also Tier 2 resources) less net internal demand calculated as a percentage of net internal demand.

[17] The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increased demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/ RTO, or other regulatory body. In some cases, the RML is a requirement. RMLs can fluctuate over the duration of the assessment period or may be different for the summer and winter seasons.

[18] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf

FIGURE ESP-24
WECC-NW POWER SUPPLY ASSESSMENT

Demand, Resources, and Reserve Margins										
Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	28,347	29,184	30,098	30,905	31,684	32,401	33,082	33,676	34,301	34,886
Demand Response	417	392	396	424	373	389	392	396	424	373
Net Internal Demand	27,930	28,792	29,702	30,481	31,311	32,012	32,690	33,279	33,876	34,512
Additions: Tier 1	5,140	5,251	5,656	5,656	5,557	5,557	5,557	5,557	5,656	5,557
Additions: Tier 2	475	1,305	1,899	2,079	2,932	2,932	2,966	2,984	3,221	2,984
Additions: Tier 3	40	677	1,148	2,589	3,113	4,438	5,734	7,479	8,960	10,027
Net Firm Capacity Transfers	2,651	3,556	3,554	2,966	2,045	928	716	320	322	0
Existing-Certain and Net Firm Transfers	33,110	33,784	33,491	32,212	31,187	30,070	29,644	27,787	26,645	25,956
Anticipated Reserve Margin (%)	36.9%	35.6%	31.8%	24.2%	17.4%	11.3%	7.7%	0.2%	-4.7%	-8.7%
Prospective Reserve Margin (%)	38.6%	40.1%	38.2%	31.1%	26.7%	20.4%	16.8%	9.2%	4.9%	0.0%
Reference Margin Level (%)	11.0%	10.8%	12.0%	11.7%	10.2%	10.1%	9.9%	9.7%	10.8%	9.4%

NW sub-region is assessed as adequate by NERC until summer of 2031. The ARM falls below the RML starting in Summer 2031. With the addition of Tier 2 capacity, the PRM stays above the RML for all years in the LTRA time horizon.

The Companies' BAA is included in the NW sub-region within the WECC. The BAA is integrated with the other sub-regions by way of transmission interconnections within the electric grid. The Companies routinely engage in purchase and sales transactions with neighboring utilities belonging to other WECC sub-regions and reserve margins in those sub-regions have the ability to impact operations in Nevada. Consequently, reserve margins in BAAs located in the other sub-regions can affect operations and capacity availability in the system as well.

The traditional methods of assessing resource adequacy at peak load times may not accurately or fully reflect the ability of the new resource mix to supply energy and reserves for all hours. Energy limitations can exist, requiring probabilistic analysis methods to identify risks to reliability that result from shortfalls in the conversion of capacity to energy (energy adequacy). The new resource mix includes natural gas-fired generation, unprecedented proportions of nonsynchronous resources, including renewables and battery storage, demand response, smart and micro-grids and other emerging technologies. Collectively, the new resources are more susceptible to energy sufficiency uncertainty.

Therefore, WECC also performs energy-based probabilistic assessments ("ProbA") looking at all hours of the year. The difference between the LTRA and the ProbA results is that the ProbA captures the expected equivalent forced outage rate for baseload resources whereas the LTRA does not. Another difference is that the ProbA looks at all hours of the year, and the LTRA looks at the peak hour only. WECC uses the Multi-Area Variable Resource Integration Convolution model ("MAVRIC"). The model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. LOLH and EUE are not anticipated in 2026 and 2027, and EUE is minimal in 2028. Results of the 2024 ProbA shown in the figure ESP-25 table below indicate negligible unserved energy and load-loss risk.

FIGURE ESP-25
WECC-NW SUMMARY OF ASSESSMENTS

Base Case Summary of Results	2026*	2026	2028
EUE (MWh)	1,722	0	1
EUE (PPM)	4	0	0
LOLH (hours per year)	0.04	0	0
Operable On-Peak Margin	37.6%	36.1%	27.8%

* Provides the 2022 ProbA Results for Comparison

Demand in WECC-NW. The Northwest is dual peaking, so the peak hour can occur in either the summer or the winter. The summer peak for the total internal demand is expected to grow from about 66.4 GW in 2024 to 78.8 GW in 2034. This represents nearly 18.7 percent load growth over the forecast horizon, with an average growth rate of 1.73 percent. There are significant differences between balancing areas, with some showing large load growth impacts while others showing a slight decrease in demand. Entities reporting large load growth cite new data centers as a primary driver.

Generation in WECC-NW. Five GW of baseload resource retirements are anticipated between 2025 and 2028. The energy needs are to be replaced by solar, wind, and BESS, further increasing variability in the portfolio. Given the retiring of baseload resources, supply chain issues preventing the construction of BESS resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage in WECC-NW. Energy storage is being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Transmission in WECC-NW. Twelve transmission projects with 500 kV and higher are planned.

Regional Market Development

FERC approved Western Resource Adequacy Program[19] ("WRAP") tariff in February 2023. The Companies continue to participate in the transitional non-binding phase as an active member. However, the Companies have made the decision to withdraw from the Western Resource Adequacy Program (WRAP) due to inherent risks that outweigh the program's current benefits for both the Companies and their customers. While the Companies continue to recognize the value of regional collaboration in resource adequacy planning to ensure reliability across the West, there are five critical issues within WRAP's existing framework that significantly elevate risk exposure. These concerns must be addressed before the Companies can consider rejoining the program.

1. **Excessive Penalty Structure and Planning Uncertainty**

The first program issue is the high penalty structure for deficiencies that occur in the forward showing timeframe which occurs seven months prior to the compliance season. WRAP has developed a penalty structure that could be a multiplier of the Cost of New Entry ("CONE") which essentially is the cost to build a gas generating plant without the benefit of receiving megawatts to help resolve any deficiency. Utilizing the most recently available CONE value, Resource Optimization calculated that penalties could range from $16 to $22 million for a 100 MW deficiency if it occurred during every month for the summer season. This makes joining the program troublesome for load serving entities that are planning to catch up and meet increasing loads in an unprecedented time. Recently, the industry has been challenged with supply chain issues, tariffs, rapid load growth, etc. The Companies are expecting 1027.9 MW of PV with 1027.9 MW paired BESS and 400 MW combustion turbines to be installed to the grid prior to and during Summer 2028 as part of the 2024 IRP approvals. However, if a project is delayed and misses its commercial operational date, then the Companies would be required in the program to replace this capacity with supply that meets the program's requirements. If the Companies are not able to meet the WRAP quality supply requirements in time for the forward showing cure period, then the Companies would face the deficiency charges.

Further complicating program compliance is the volatility of the PRM. Year-over-year changes have ranged from minor adjustments to swings as large as 10 percent. For a monthly peak load of 10,000 MW, this could translate to an unexpected need for 1,000 MW of additional capacity, which is an unrealistic burden to meet within such a short timeframe. This level of variability is too large to occur on such a short period, leaving little to no time for a participant to react and procure the additional supply. The Companies are pleased that the program is initiating the process to potentially revise the policy and address this issue beginning in July 2025. However, the resolution of this issue will likely occur after the deadline, October 31, 2025, to withdraw from the program in order to not become a binding participant.

[19] https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program.

2. **Governance Challenges and Market Participation Conflicts**
The second issue of the program is the current WRAP governance structure following the recent approval of the Markets+ tariff approach, which requires all load serving entities within that market to be a WRAP participant. While expanding participation can enhance regional reliability, it may disadvantage entities that prefer to remain in the Western Energy Imbalance Market ("WEIM") or transition to the Extended Day-Ahead Market ("EDAM"). It is expected that each year new participants will join the WRAP as Markets+ moves through implementation, adding new balancing authority areas. Any third-party, load serving entities that are in a balancing authority area that joins Markets+ will also be required to join WRAP. This will add additional members that are not currently participating in the program along with additional load, increasing the number of voting members that participate in a specific market.

In the Resource Adequacy Participant Committee, each member gains a vote utilizing a house and senate model to vote on program changes that, if approved, will move to the Board. ThAs this new market moves through implementation it is not unreasonable to assume that the participants within that market may need to propose and implement changes to accommodate Markets+ since WRAP participation is mandatory for those members. It is unknown if such changes would or would not harm the members that are remaining in the WEIM or leaning towards EDAM, but it is possible, considering the participants in this minority group will likely lose their veto power with new member additions. Additionally, there is a two-year exit provision in the program. The outcome could be that a change passed through the governance process could harm the WRAP participants who also participate in another market, and those participants would be compelled to bear the burden of those provisions until they are able to exit the program.

3. Absence of Market Oversight and Procurement Mechanisms

The third program issue is that WRAP has created a new market product in the west without the creation of a capacity market or method for procuring additional supply with the oversight of a market monitor. The WRAP program was originally designed to be voluntary in nature, especially considering the high deficiency penalties. A deficiency charge or penalty is assessed to a participant that is unable to meet the forward showing requirement with qualifying supply that meets the WRAP requirements. In fact, FERC has stated:

> The proposed WRAP Tariff sets forth the framework for a new voluntary resource adequacy planning and compliance program in the Western Interconnection. In this order, we accept WPP's proposed WRAP Tariff, effective January 1, 2023, as requested.[20]

Following the approval of the voluntary WRAP tariff, Markets+ filed its tariff requiring that all market load serving entities be a member of WRAP.

[20] Northwest Power Pool, 182 FERC ¶ 61,063 (2023).

> [Southern Power Pool ("SPP")] states that the proposed Markets+ Tariff requires Markets+ load responsible entities to submit attestations that (1) they will participate in WRAP and (2) will satisfy all applicable requirements of the WRAP Tariff.[21]

This approved tariff fundamentally changes WRAP in that it is no longer a voluntary resource adequacy program.

The requirement ensures that all Markets+ participants meet the forward showing supply requirements or pay the deficiency charges for each winter and summer season. Since not all participants may have enough supply to meet the resource adequacy requirements, they will likely need to purchase this supply ahead of the forward showing season. WRAP has specific and strict guidelines for purchasing additional supply in which both the seller and buyer must attest that both parties have met the requirements for the supply to count towards the forward showing. 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 attestation affirming the capacity being utilized will not be committed to other needs. These requirements are above the commonly used WSPP Inc.'s ("WSPP") Schedule C contract which includes financial penalties if the supplier fails to deliver. Since the program is a requirement to participate in a market, this has created a new issue that load serving entities will be required to procure WRAP compliant supply if they cannot meet the requirements on their own. This extends this issue to others that are short within the region and need to purchase WRAP compliant supply due to the competition to receive a product for a program that has very high penalties if no such product can be found. Most of the resources in the WECC region are associated with vertically integrated utilities that must ensure supply to their native load before engaging in bilateral sales. Thus, there is an extremely limited number of suppliers that have both seven-month ahead capacity availability and associated firm transmission rights. As stated earlier, WRAP was designed to be a voluntary program, therefore, no market monitoring department was created to oversee the program. Markets+ simply added the program as a requirement in its tariff. Meaning that the market monitor that has authority over the Markets+ tariff will not have authority over WRAP. This lack of oversight leads to the possibility of suppliers taking advantage and offering supply at or near the deficiency charge penalties. This would significantly disadvantage customers in the west from receiving competitive supply that satisfies the forward showing requirements.

4. Underutilization of Transmission and Diversity Potential

The fourth program issue is the conservative approach that the program utilizes to model the transmission connectivity amongst the program's participants. WRAP models the participants in two separate sub regions with limited transmission connectivity between them. This modeling

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[21] *Southwest Power Pool, Inc.*, 190 FERC ¶ 61,030 (2025).

approach does not consider a large amount of the transmission that has been utilized and available through the WEIM. It is notable that the program has strict firm transmission requirements, and that the Available Transfer Capability ("ATC") determined in real-time is not firm enough to qualify under the program rules. However, there has been significantly more transmission capability that has occurred through market participation than the 500 MW assumed by the program. Therefore, it is the Companies' perspective that the program undervalues this transmission capability which eliminates any major diversity benefit from occurring in the forward showing, resulting in higher PRMs. The program should not artificially set the transmission requirement on a definition of OATT firm transmission; but instead, should perform historical studies to determine what transmission has been available seasonally.

5. Uncertainty Around Operational Holdback Availability

The fifth program issue is the uncertainty around the operational program's holdback of capacity. WRAP is untested because the program has yet to establish a binding season. The Companies question whether or not holdback will be available if a heat wave occurs and Nevada needs to call on the program for supply. The concept of holding back capacity for program participants has been the valuable proposition for the program. Program members agree to supply surplus to another participant when deficient. However, the program models the participants at two subregions separating the southwest from the northwest participants and does not perform sharing amongst the two subregions in the operational program. This is not advantageous when weather events in the recent past have occurred over large areas of the desert southwest that have benefitted from connectivity to available supply from the northwest.

Additionally, the program only measures surplus capacity up to the forward showing requirement, minus an uncertainty factor. Meaning that any capacity that is available above each individual forward showing requirement is not considered for the sharing calculation and can be thought of as out of the program. Considering the lack of sharing between the two subregions and the lack of additional supply above the forward showing requirement minus uncertainty, it is reasonable to assume that the operational program's concept of holdback may not actually be available in the southwest in the event of a large heatwave.

For all the reasons outlined above, the Companies have elected to withdraw from WRAP. The Companies will continue to monitor the program's development and remain open to future participation should WRAP evolve to address these five critical issues. Until then, the Companies will pursue alternative avenues to ensure regional reliability and resource adequacy for their customers.

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. Two day-ahead markets were under consideration by the Companies: CAISO's Expanded Day-Ahead Market ("EDAM") and SPP's Markets+. 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 performed due diligence on both day-ahead market options.

Based on a holistic view of these qualitative and quantitative factors, the Companies intend to request authorization from the PUCN to participate in the CAISO EDAM. As the second participant in the 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 hopes 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 ("BANC"), Los Angeles Department of Water and Power ("LADWP"), Portland General Electric, Public Service Company of New Mexico, Imperial Irrigation District, Turlock Irrigation District, PowerWatch and Idaho Power provides a significant degree of interconnectivity and supports a diversity of resources. Moreover, the approval of the SWIP-North transmission by CAISO and Idaho Power will only enhance the transfer capacity of the existing On Line transmission line in Nevada, bringing even greater benefits to all EDAM participants.

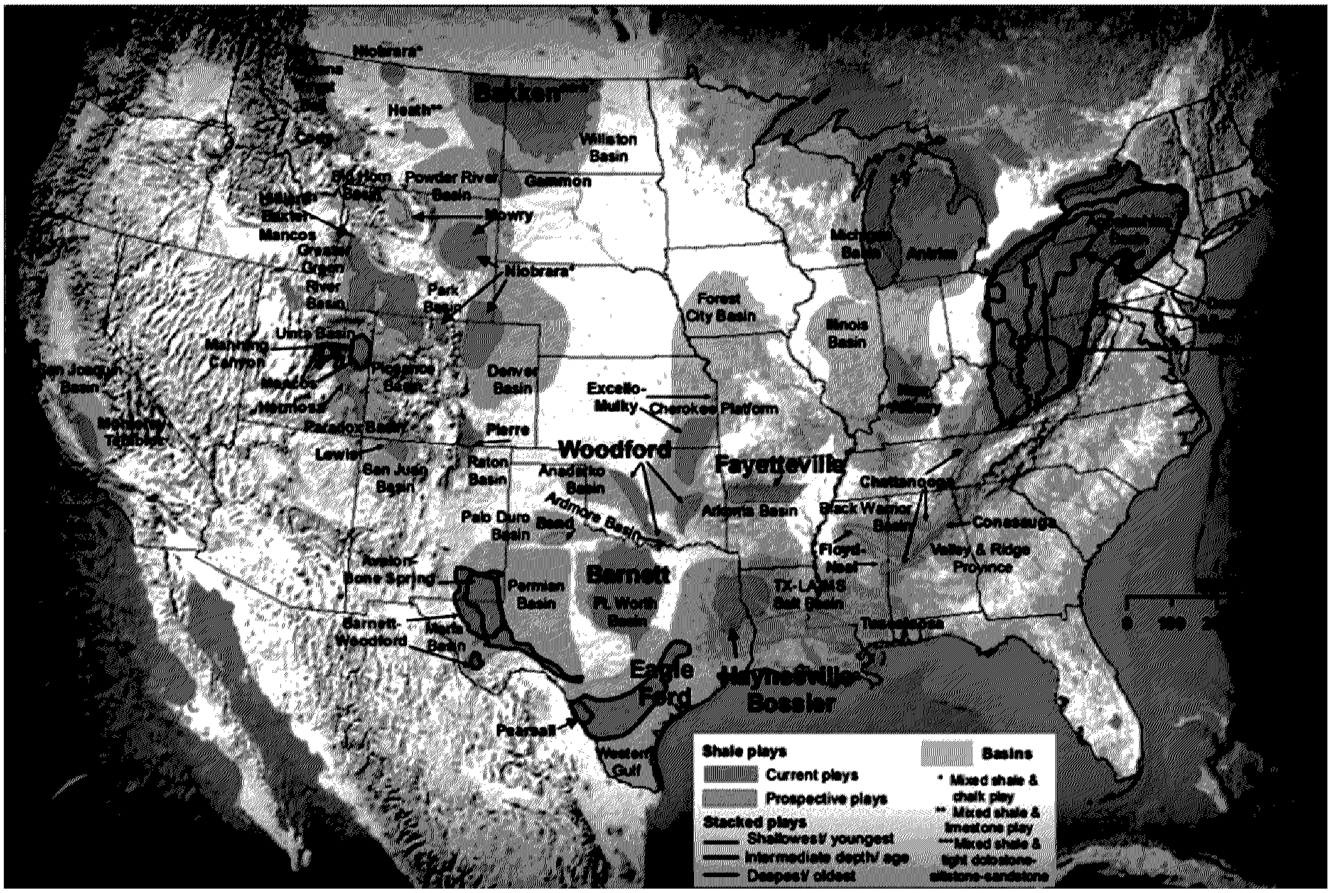
2. NATURAL GAS

As North American power markets continue to transition to cleaner energy sources (*e.g.*, natural gas and renewables), natural gas will be the driving determinant of market power prices as well. Natural gas is widely considered to be a critical energy source for the future, with fossil fuels remaining the dominant source of energy powering the world economy. In particular, the abundance of natural gas, coupled with its relative environmental attributes and multiple applications across all sectors, means that it will continue to play an important role in meeting demand for energy in the United States.

Market fundamentals indicate the availability and reliability of physical gas supplies to be adequate for satisfying natural gas demand for the foreseeable future. Prices for gas will fluctuate depending upon demand (often weather-related), economics of drilling, and finally federal and state decarbonization efforts. On a short-term basis, demand for natural gas has traditionally been seasonal. As a general matter, demand is highest during the winter, the primary driver being residential and commercial heating. Natural gas in storage typically declines in the winter as it is consumed during peak usage, then is injected back into storage in the spring and summer months in order to rebuild storage levels for the next winter's drawdown. Besides weather, the general state of the economy can have a considerable effect on the demand for natural gas in the short term, particularly for industrial consumers. When the economy is expanding, output from industrial sectors generally increases at a similar rate. When the economy is in recession, output from industrial sectors drops.

The Companies currently purchase most of the natural gas supply burned in their power plants from the Western Canadian Sedimentary Basin in Alberta and British Columbia, Canada. The Companies also access natural gas supplies from the Rockies region, principally the states of Wyoming, Colorado, and Utah. In 2024, most production growth came from the Permian region in Texas and New Mexico, where most natural gas production is associated natural gas, meaning producers' oil-drilling activities in the region determine natural gas production levels. Natural gas production regions are presented in figure ESP-26 bellow.

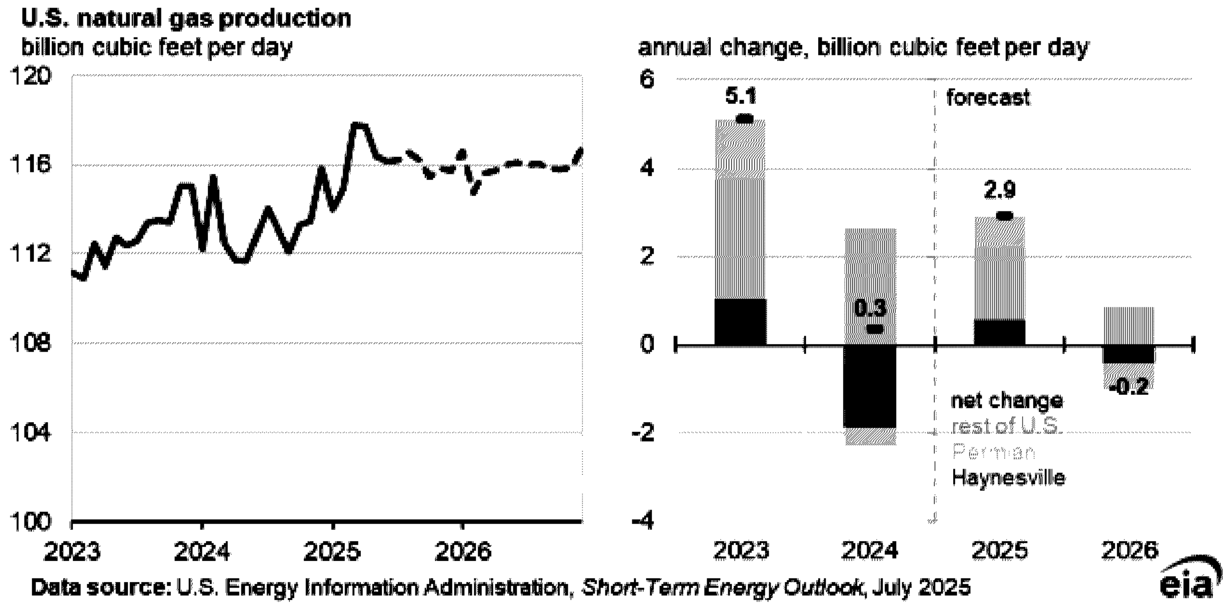
FIGURE ESP-26
U.S. NATURAL GAS PRODUCTION REGIONS



Natural gas production Marketed natural gas production averaged 116.8 billion cubic feet per day (Bcf/d) in 2Q25, a 4.7 Bcf/d increase compared with the same period in 2024.[22] The Energy Information Administration ("EIA"), in its July short-term energy outlook ("STEO"), expects production to remain near this level through 2026, averaging around 116 Bcf/d in both 2025 and 2026. Higher natural gas prices throughout 2025 compared with last year are supporting this sustained production. U.S. Natural Gas production is presented in figure ESP-27 bellow.

[22]https://www.eia.gov/outlooks/steo/pdf/steo_full.pdf.

FIGURE ESP-27
U.S. NATURAL GAS PRODUCTION

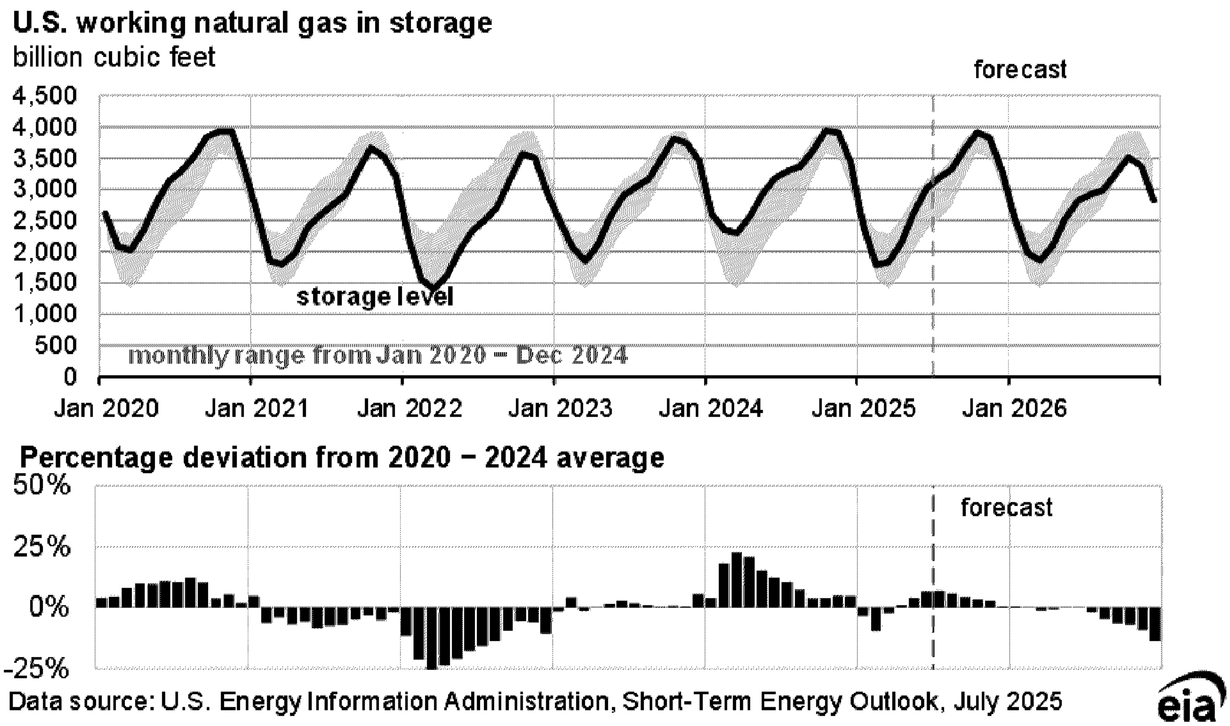


U.S. marketed natural gas production is forecasted to increase almost three percent this year compared with 2024, largely because of rising production in the first half of the year. This increase is driven mainly by the Permian region, which is expected to produce 27.0 Bcf/d in 2025, or six percent more than in 2024, along with increases in the Appalachia and Haynesville regions.[23] U.S. marketed natural gas production is expected to remain flat in 2026 as production growth from the Permian and Appalachia regions will offset the overall decline in production from the rest of the United States.

Natural gas storage. In its July STEO, EIA estimates that U.S. natural gas inventories were seven percent above the five-year average (2020–2024) at the end of June after ending the withdrawal season (November–March), four percent below the five-year average, the lowest in three years. Injections have exceeded the five-year average as U.S. natural gas production has increased in the second quarter of 2025 compared with first quarter of 2025. Expecatation is that inventories will end the injection season on October 31 with 3,910 Bcf of natural gas in storage, three percent more than the five-year average. Working gas storage levels for the United States in 2020-2025, with the forecast for the remainder of 2025 and 2026 are illustrated in Figure ESP-28.

[23]https://www.eia.gov/outlooks/steo/pdf/steo_full.pdf.

FIGURE ESP-28
U.S. NATURAL GAS STORAGE



Movement in natural gas prices can be partly attributable to natural gas storage levels. Relative shortages or excesses of storage capacity during heavy load periods (typically November through March) can either create or hinder the daily volatility of natural gas prices. The consuming West region has the smallest share of gas storage, both in terms of the number of sites, as well as gas capacity/deliverability.

Arizona, Idaho and Nevada do not have any underground storage sites within their borders. Approximately 63 percent of total storage capacity in the West is located in California and Montana. Moreover, the bulk of the region's working gas capacity is located in California's 14 underground natural gas storage sites, seven of which are owned by the two principal gas distributors in the State: Southern California Edison ("SoCal") and Pacific Gas & Electric ("PG&E"). Most of their storage capacity is used for system balancing and as a way of maintaining a steady and high utilization of contracted pipeline capacity from Canada, the Rocky Mountains, and the Southwest.

The seven independent storage facilities in California (not owned by either SoCal or PG&E) are used primarily as depositories for gas produced within the State that is not immediately marketable. In addition, these sites are connected to (and deliver their withdrawals to) the SoCal and/or PG&E

systems. Storage facilities in Washington and Oregon are used primarily to provide seasonal backup to several local distribution companies located in the Northwest and are crucial in maintaining their operational flexibility and system integrity. These storage facilities are also used by some Canadian shippers/customers to support their marketing and operational needs. The import/export facilities of NWPL at Sumas, Washington, are used to move natural gas in either direction to storage, depending on marketing conditions.

Natural gas prices. The U.S. benchmark Henry Hub spot price averaged $3.67/per MMBtu in first half of 2025, compared with $2.11/MMBtu in first half of 2024. With more natural gas in storage in this forecast, lower natural gas prices are expected, which should average just almost $3.40/MMBtu in 3Q25.[24]

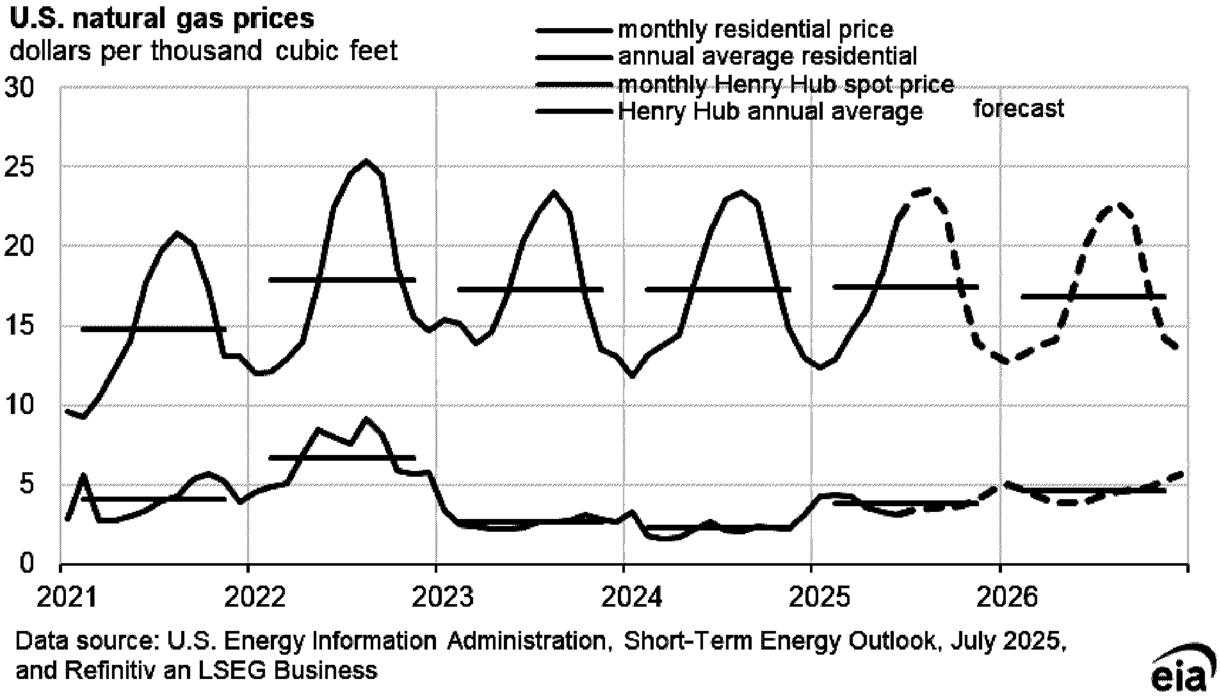
EIA expects natural gas consumption to grow in all sectors in 2025 except the industrial sector, where the consumption is expected to decrease slightly. Sectoral changes in natural gas consumption depend mostly on the weather. Natural gas-fired power plants provide about 40 percent of U.S. electricity generation annually, so electricity demand from heating and air-conditioning equipment influences how much natural gas the electric power sector consumes.

In the residential and commercial sectors, colder temperatures in the winter also affect direct natural gas consumption by heating equipment. The mix of energy sources and technologies used to generate electricity also affects natural gas consumption in the electric power sector. As developers add more generating capacity from solar- and wind-powered generators, those generators' incremental generation may reduce the need to dispatch natural gas-fired power plants. Changes in the timing and magnitude of new solar and wind capacity would also affect the forecast for natural gas consumption in the electric power sector.

Historical and forecasted natural gas Henry Hub monthly average spot prices for period 2020-2025 are ilustrated in figure ESP-29.

[24]https://www.eia.gov/outlooks/steo/pdf/steo_full.pdf.

FIGURE ESP-29
HENRY HUB MONTHLY SPOT PRICES



Liquified Natural Gas ("LNG") demand and natural gas production will be two key drivers of price in the coming months. If LNG demand is more or production is less than forecast, inventories may end the injection season below forecast and natural gas prices may be higher than forecast. At the same time, with above-normal hurricane activity expected this summer, LNG exports may be disrupted if storms hit along the Gulf Coast, which could result in more U.S. inventories and lower natural gas prices than expected.

B. FUEL AND PURCHASED POWER PRICE FORECASTS

The Companies' forecasting process for fuels and regional power prices encompasses an assessment of historic and forecast information and related industry data that is obtained from professional services or is publicly available. The outlook on future price trends is reviewed from several sources including forward markets, the results of RFPs, and reputable independent market forecasting services, such as Argus Media ("Argus"), Wood Mackenzie ("WoodMac"), and the EIA.

The methodology used to prepare the base case forecasts for power and natural gas prices relies upon observable market quotes in the near-term forecast years, which are gradually blended into long-term price forecasts obtained from an external consulting firm specializing in market fundamentals and fundamental price forecasting. The price forecast curves for power and natural gas are important to the economic evaluation of alternative electric resource plans.

Market quotes used for short-term forecast. Market quotes consist of observed trades in the relevant trading hubs: for natural gas, the Henry Hub, Alberta NOVA Inventory Transfer ("AB-NIT" or "AECO"), Sumas, Northwest Pipeline Rockies ("Rockies"), Malin, and South California Border ("SoCal"); and for power, the Mead and the Palo Verde trading hubs. The source of market quotes is Argus for natural gas prices and for western regional power prices. The market quotes for the ESP forecast were prepared as an average of settlement prices for a 21-day trading period from May 1, 2025, through May 31, 2025.

Fundamental (long-term) forecast. The fundamental forecasts of power and natural gas prices are provided through a subscription service with WoodMac, a global energy, metals and mining consultancy service. WoodMac maintains an international reputation for supplying comprehensive data, written analysis and consultancy advice. It performs detailed fundamental modeling of regional electric and natural gas systems, taking into account structural supply-demand price dynamics. For internal consistency, WoodMac's projections of natural gas and power prices are taken from a single integrated forecast, the long-term outlook (Decarbonization Headwinds Update, released in February of 2025.)

1. NATURAL GAS PRICE FORECAST

Base natural gas price forecast. The monthly gas price forecast by regional hub begins with the 21-day average trading period of market quotes from May of 2025. The natural gas price monthly forecast for January 2026 - December 2027 was prepared utilizing pure market quotes from the Argus trading settlements for Henry Hub plus western regional basis quotes. [25]

[25] The prices at western delivery hubs are commonly quoted as a basis to the Henry Hub.

The base fuel-mid CO2 monthly natural gas price forecast, used for the dispatching purposes, SoCal and Malin natural gas hubs, is shown in Figure ESP-30

FIGURE ESP-30
NATURAL GAS PRICE FORECASTS

[redacted]

High and low gas prices. The Companies also prepared high and low sensitivities around the base case market price forecasts. An assumption of plus-and-minus one standard deviation around the base gas price forecast was computed for the high and low cases. Market quotes of implied volatilities from at-the-money call options from May 2025 were used to calculate the the high and low natural gas prices.

The base, high and low-price projections, that result from applying the volatility curve and used for the fuel costs, Rockies and Alberta (AECO) natural gas hubs, are illustrated in Figures ESP-31 and ESP-32.

FIGURE ESP-31
NATURAL GAS PRICE FORECAST (ROCKIES)

[redacted]

FIGURE ESP-32
NATURAL GAS PRICE FORECAST (ALBERTA)

[redacted]

2. POWER PRICE FORECAST

Prices for western wholesale power markets are forecasted monthly for both on-peak and off-peak periods.[26] The power price forecast is almost exclusively based on prices at Mead hub. The natural gas price monthly forecast for January 2026 - December 2027 was prepared utilizing pure market quotes from the Argus trading settlements for Mead hub. The Mead prices are based on an average of 21 trading days in May of 2025.

Also, as with the natural gas price forecast, high and low power price sensitivities were developed for describing potential retail price volatility. The high and low power price forecasts were prepared to reflect western energy prices that fluctuate with the respective high and low natural gas price forecasts. For both on-peak and off-peak periods, the power prices are calculated by first

[26] On-peak in the WECC region is the 16-hour period, from 6 a.m. to 10 p.m., Monday through Saturday. Off-peak is the balance of hours in the week.

multiplying the high and low natural gas prices with the heat rate of a high-efficiency combined cycle generator. The product of this calculation is added to the monthly on-peak spark spreads from the base case price forecast to compute the high and low energy prices. Figure ESP-33 shows the monthly forecast of on-peak power prices for Mead power hub for 2026-2027 for base, high and low fuel cases.

FIGURE ESP-33
POWER PRICE FORECAST (MEAD -ON-PEAK)

[redacted]

SECTION 4 – POWER PROCUREMENT PLAN

This section explains how the Companies' power procurement plan meets the requirements of NAC § 704.9494. See also NAC § 704.9153, which defines "purchased power procurement plan" as "a plan which establishes the parameters of a purchased power portfolio for a utility and which balances the objectives of:

1. Minimizing the cost of purchased power;
2. Minimizing retail price volatility; and
3. Maximizing the reliability of purchased power over the term of the energy supply plan."

A. POWER PORTFOLIO AND OPTIMIZATION PROCEDURES

The Companies meet the energy demand of their customers through a combination of the Companies' generating units, long-term PPAs, and short-term transactions.

The Companies meet the requirements of Nevada's RPS through a combination of Commission-approved long-term PPAs with renewable energy resources and agreements for purchase of PCs. The Companies also sell PCs under the NGR program.

Figures ESP-34A and ESP-34B list all of the Companies' renewable and non-renewable PPAs, and sales agreements.

FIGURE ESP-34A
NEVADA POWER LONG-TERM PPAs

Contract Name	Contract Type	Capacity (MW)	Commercial Operation Date	Termination Date
Renewable Purchase Agreements				
PPAs (Commercial)				
ACE Searchlight[QF]	Solar[S]	17.5	12/16/14	12/31/2034
APEX Landfill[QF]	Methane	12.0	03/01/12	12/31/2032
Boulder Solar I[EWG]	Solar[S]	100.0	12/09/16	12/31/2036
Colorado River Commission-Hoover	Hydro	237.6	10/01/17	09/30/2067
Copper Mountain 5[EWG]	Solar[S]	250.0	07/23/21	12/31/2046
Desert Peak 2[QF]	Geothermal	25.0	04/17/07	12/31/2027
Eagle Shadow Mountain[EWG]	Solar[S]	300.0	05/10/23	12/31/2048
FRV Spectrum[QF]	Solar[S]	30.0	09/23/13	12/31/2038
Gemini Solar[EWG]	Solar[S, X=380 (3.7 hrs) 3]	690.0	03/25/24	12/31/2049
Jersey Valley[QF]	Geothermal	22.5	08/30/11	12/31/2031
McGinness Hills[QF]	Geothermal	96.0	06/20/12	12/31/2032
Moapa (Arrow Canyon) Solar[EWG]	Solar[S, X=74 (5 hrs) 3]	200.0	12/08/23	12/31/2048
Mountain View[EWG]	Solar[S]	20.0	01/05/14	12/31/2039
Nevada Solar One (NPC)[QF]	Solar[T, X]	46.9	06/27/07	12/31/2027
NGP Blue Mountain[QF]	Geothermal	49.5	11/20/09	12/31/2029
RV Apex[QF]	Solar[S]	20.0	07/21/12	12/31/2037
Salt Wells[QF]	Geothermal	23.6	09/18/09	12/31/2029
Silver State[EWG]	Solar[F]	52.0	04/25/12	12/31/2037
Spring Valley[EWG]	Wind	151.8	08/16/12	12/31/2032
Stillwater Geothermal[1, QF]	Geothermal	47.2	10/10/09	12/31/2029
Stillwater PV[1, QF]	Solar[F]	22.0	03/05/12	12/31/2029
Switch Station 1[EWG]	Solar[S]	100.0	08/08/17	12/31/2037
Switch Station 2 (NPC)[EWG]	Solar[S]	0.0	10/11/17	12/31/2037
Techren I[EWG]	Solar[S]	100.0	03/11/19	12/31/2044
Techren III[QF]	Solar[S]	25.0	10/07/20	12/31/2045
Techren V[EWG]	Solar[S]	50.0	12/31/20	12/31/2045
Tuscarora[QF]	Geothermal	32.0	01/11/12	12/31/2032
WM Renewable Energy-Lockwood[QF]	Methane	3.2	04/01/12	12/31/2032
	Total	**2723.8**		
PC Purchase Agreements				
Sierra Pacific Power	Geothermal	2.3	10/30/09	12/31/2028
Nellis I (Solar Star)[QF]	Solar	13.2	12/15/07	12/31/2027
SunPower (LVVWD)	Solar	3.0	04/20/06	12/31/2026
	Total	**18.5**		
PPAs (Pre-Commercial)[2]			**Estimated COD**	**Termination Date**
Dry Lake East	Solar[S, X=200(4hrs)]	200.0	12/01/26	12/31/2051
Boulder Solar III	Solar[S, X=127.9(4hrs)]	127.9	06/01/27	12/31/2052
Libra Solar	Solar[S, X=700(4hrs)]	700.0	12/01/27	12/31/2052
	Total	**1027.9**		
Non-Renewable Purchase Agreements				
Renewable and Non-Renewable Sales				
Switch NGR (Switch Station 1)	NGR Agreement (Sale of PCs)	100.0	08/08/17	12/31/2037
Switch NGR-NPC (Switch Station 2)	NGR Agreement (Sale of PCs)	0.0	10/11/17	12/31/2037

Notes:
1. The geothermal and solar facilities are combined into one PPA.
2. Facilities are either under development or construction (the dates shown are expected dates).
3. Storage reflects current MW based on annual storage capacity test

QF=Qualifying Facility, EWG=Exempt Wholesale Generator, S=Single Axis Tracking, T=Solar Thermal (Tracking), F=Fixed Tilt,

FIGURE ESP-34B

Contract Name	Contract Type	Capacity (MW)	Commercial Operation Date	Termination Date
Renewable Energy				
PPAs (Commercial)				
Battle Mountain[EWG]	Solar[S,X=24.2MW (4 hrs) 6]	101.0	6/23/2021	12/31/2046
Boulder Solar II[EWG]	Solar[S]	50.0	1/27/2017	12/31/2037
Burdette[QF]	Geothermal	26.0	2/28/2006	12/31/2026
Dodge Flat[EWG]	Solar[S,X=50MW (4 hrs) 6]	200.0	3/2/2022	12/31/2047
Fish Springs Ranch[EWG]	Solar[S,X=24.91MW (4 hrs) 6]	100.0	3/15/2022	12/31/2047
Galena 3[QF]	Geothermal	26.5	2/21/2008	12/31/2028
Hooper[1,QF]	Hydro	0.8	6/23/2016	12/31/2040
Kingston[1]	Hydro	0.2	9/19/2011	12/31/2040
Mill Creek[1]	Hydro	0.0	9/1/2011	12/31/2040
Nevada Solar One (SPPC)[QF]	Solar[T,X]	22.1	6/27/2007	12/31/2027
North Valley[QF]	Geothermal	25.0	4/26/2023	12/31/2048
OWGP Beowawe[QF]	Geothermal	20.0	1/10/2025	12/31/2053
RO Ranch[1,2]	Hydro	0.0	3/15/2011	12/31/2040
Switch Station 2 (SPPC)[EWG]	Solar[S]	79.0	10/11/2017	12/31/2037
Techren II[EWG]	Solar[S]	200.0	10/4/2019	12/31/2044
Techren IV[QF]	Solar[S]	25.0	10/7/2020	12/31/2045
TMWA Fleish	Hydro	2.4	5/16/2008	6/1/2028
TMWA Verdi	Hydro	2.4	5/15/2009	6/1/2029
TMWA Washoe	Hydro	2.5	7/25/2008	6/1/2028
Turquoise[EWG]	Solar[F]	50.0	12/4/2020	12/31/2045
USG San Emidio[QF]	Geothermal	11.8	5/25/2012	12/31/2037
	Total	**944.6**		
PC Purchase Agreement				
TMWRF	Methane	0.8	9/9/2005	9/1/2026
PPAs (Pre-Commercial)[3]			**Estimated COD**	**Termination Date**
Ormat Western Geothermal Portfolio (OWGP)[5]				
OWGP Lone Mountain[QF]	Geothermal	15.0	10/1/2028	12/31/2053
OWGP North Valley 2[QF]	Geothermal	0.0		
OWGP Pinto[QF]	Geothermal	15.0	1/1/2027	12/31/2053
OWGP Galena 1 [QF]	Geothermal	15.0	2/1/2027	12/31/2053
OWGP Gerlach[QF]	Geothermal	0.0		
OWGP Desert Peak 2[QF]	Geothermal	10.0	2/1/2028	12/31/2053
OWGP Galena 3[QF]	Geothermal	15.0	1/1/2029	12/31/2053
OWGP TBD	Geothermal	30.0	TBD	12/31/2053
Corsac Generating Station 2 LLC	Geothermal	115.0	2/1/2030	12/31/2045
	Total	**215.0**		
Non-Renewable Purchase Agreements				
Liberty (CalPeco) EBSA	Diesel	12.0	1/1/2011	12/31/2031
	Total	**12.0**		
Renewable & Non-Renewable Sales Agreements				
Liberty (CalPeco)	Full Requirements (Capacity/Energy/PCs)	See Note 4	12/30/2020	12/29/2025
NPC-SPPC	Sale of PCs (Geothermal)	2.3	10/30/2009	12/31/2028
Apple NGR (Fort Churchill Solar)	NGR Agreement (Sale of PCs)	19.5	8/5/2015	8/4/2040
Apple NGR (Boulder Solar II)	NGR Agreement (Sale of PCs)	50.0	1/27/2017	12/31/2037
Switch NGR-SPPC (Switch Station 2)	NGR Agreement (Sale of PCs)	79.0	10/11/2017	12/31/2037
Apple NGR (Techren II)	NGR Agreement (Sale of PCs)	200.0	10/4/2019	6/20/2044
Apple NGR (Turquoise)	NGR Agreement (Sale of PCs)	50.0	12/4/2020	4/30/2045

Notes:
1. The illustrative termination date shown is subject to certain conditions, which may result in termination before or after December 31, 2040.
2. RO Ranch Hydro facility is shut down indefinitely (the PPA is still active).
3. Facilities are either under development or construction (the dates shown are expected dates).
4. The current monthly contract demand ranges from approximately 70 MW (June) to 140 MW (December).
5. Portfolio consists of eight facilites under one Power Purchase Agreement
6. Storage reflects current MW based on annual storage capacity test

QF=Qualifying Facility, EWG=Exempt Wholesale Generator, S=Single Axis Tracking, T=Solar Thermal (Tracking), F=Fixed Tilt, X=Storage

SIERRA LONG-TERM PPAs

1. RENEWABLE POWER PURCHASE AGREEMENTS

Nevada Power has executed 30 long-term renewable PPAs (see Nevada Power Figure ESP-34A above) representing a total nameplate capacity of approximately 3,751.7 MW.

Nevada Power has one company-owned asset, Dry Lake Solar (150 MW with 100 MW of storage), which is managed as a PPA and achieved commercial operation on May 2, 2024.

Nevada Power has also executed three long-term PC only purchase agreements representing a total nameplate capacity of approximately 18.5 MW. Nevada Power's renewable purchase agreements secure a mix of solar, geothermal, hydro, methane, and wind resources.

Sierra has executed 22 long-term renewable PPAs representing a total nameplate capacity of approximately 1,159.6 MW (see Sierra Figure ESP-34B above). The latest commercial addition to the portfolio was OWGP Beowawe (20 MW), which achieved commercial operation in January 2025. Also, in June 2025, TCID New Lahontan terminated (-4 MW).

Sierra has executed one long-term PC only purchase agreement representing a nameplate capacity of 0.8 MW. Sierra's renewable PPAs secure a mix of solar, geothermal, and hydro resources.

2. NON-RENEWABLE POWER PURCHASE AGREEMENTS

Sierra has executed one long-term non-renewable PPA with Liberty, pursuant to which Sierra purchases 12 MW of capacity from Liberty's Kings Beach diesel units for emergency purposes. This agreement expires December 31, 2031.

3. RENEWABLE AND NON-RENEWABLE SALES AGREEMENTS

Nevada Power has executed two long-term agreements under the NGR program for the sale of PCs to Switch Ltd. (associated with the output of the Switch Station 1 solar facility).

Sierra has executed five long-term agreements under the NGR program for the sale of PCs to Apple (associated with the full output of the Fort Churchill Solar Array, Boulder Solar II project, Techren Solar II project, and the Turquoise Solar project), and Switch Ltd. (associated with the full output of the Switch Station 2 project). Sierra has also executed one long-term agreement for the sale of PCs to Nevada Power. This PC only sale agreement expires December 31, 2028.

In addition, Sierra has executed a full requirements agreement with Liberty whereby Sierra sells capacity, energy, and certain PCs to meet the needs of Liberty retail customers in California. The current monthly contract demand ranges from approximately 70 MW (June) to 140 MW (December). The term of the agreement is December 30, 2020, through December 29, 2025.

4. CURRENT PORTFOLIO OPTIMIZATION PROCEDURES

The Companies' resource portfolio is adjusted continuously based upon many factors, including changes in expected load, changes in system conditions, system reliability needs, and changes in market conditions. The Companies continuously monitor the resources available to meet load obligations, recognizing the uncertainty not only in system conditions but also in regional energy markets organized across different commodities, locations, and trading timeframes. Forward prices are continuously monitored for comparison with the internal generation costs. As conditions change and new information becomes available, the Companies optimize their portfolio to account for changes in load, cost, volatility, reliability, and other commercial or technical factors.

Each month, the Companies assess their capacity and energy positions for the upcoming month by taking into account planned unit outages, available resources, forecasted system loads and forecasted reserve requirements. If the assessment shows that the Companies are expected to be short in terms of meeting system load and reserve requirements in the upcoming month, the Companies may purchase energy or capacity. The Companies utilize both RFP processes and direct negotiations with approved counterparties to fill short capacity and energy positions.

Short-term energy transactions may be made either for economic reasons or in order to maintain the reliability of the transmission grid. The circumstances in which adjustments may be made for reliability purposes include unexpected loss of generation due to forced outages or capacity constraints, imbalances between supply and demand of non-native load customers, actual loads being higher than the amount forecasted, and transmission constraints due to forced outages or other unanticipated contingencies impacting transmission facilities inside or outside the Companies' transmission network. In any of these circumstances, the transmission system may enter a condition under which, absent an adjustment to short-term transactions, one or more of the requirements of the applicable reliability standards will be violated. Operation in violation of the requirements of the applicable reliability standards poses undue risk to the reliable and secure operation of the bulk electric system and can also result in monetary sanctions for non-compliance. In addition to participation in the EIM as described above, the remedy for a negative imbalance between load and resources is the procurement of emergency resources to regain such balance and restore the required reserve margins.

The Companies also prepare day-ahead plans. On a daily basis, the Companies forecast their energy position and generation costs for the scheduling day using a production cost simulation model. Internal generation costs are compared to actual energy market prices to identify opportunities to sell into the market and mitigate customer costs. The Companies' traders determine actual energy market prices by communicating with other traders and by monitoring the Intercontinental Exchange ("ICE"), a trading platform for global commodity and financial products marketplaces, including electronic energy markets. Purchase or sales opportunities are evaluated on the basis of economic and reliability considerations.

On the day of delivery, the Companies continue to compare hourly generation costs to hourly energy market prices, monitor hourly weather patterns and actual generation and transmission availability and costs, and assess hourly energy market conditions in order to balance loads and resources across the day. The Companies' traders ascertain real-time market conditions by conducting market surveys through communications with other counterparties. Again, purchase or sales opportunities are evaluated on the basis of economic and reliability considerations.

In the delivery operating hour, the power portfolio is further optimized through participation in the EIM operated by the CAISO. The EIM utilizes a security constrained economic dispatch model to dispatch resources in five-minute intervals in the participating balancing authority areas. Subject to state and federal regulatory approvals, the Companies began participating in the EIM on December 1, 2015. The Companies' traders determine which resources are available for participation in the EIM and voluntarily submit bids to the market operator for EIM purchases or sales. Participation in the EIM does not absolve the Companies from compliance with reliability standards or the obligation to meet customer demand.

5. CONTINUOUS MONITORING AND OPTIMIZATION OF THE POWER PORTFOLIO

As opportunities present themselves, the Companies can make forward power sales by entering direct negotiations with counterparties. Forward sales transactions can be pursued if there is confidence that a long capacity and/or energy position will exist and the transaction will yield positive economic benefits for bundled retail customers. The products to be sold on a forward basis may include heat rate call options, indexed power, fixed-price power, ancillary services products, or other products as approved. Also, forward power sales may be accompanied by forward gas procurement. The Companies will not make forward sales for delivery more than three seasons in advance (including the current gas season), unless authorized by the Commission.

Day-ahead or day-of power purchases and sales also continue to be made. If there is an open position or if system costs of decremental energy exceed the additional cost of market purchases, a purchase will be made. Similarly, if system costs of incremental energy are less than the market price, day-ahead or day-of power may be offered for sale.

B. SUMMARY OF POWER PROCUREMENT PLAN

The Companies' proposed power procurement plan includes the following elements:

- The Companies propose to continue the four-season laddering strategy to fill the remaining open positions in summers of 2026 and 2027.

- In addition to the request for proposal process, the Companies propose to negotiate and transact directly with counterparties. The Companies will evaluate all available products and determine the most prudent transaction plan based on cost and deliverability.

- The Companies will continue to monitor the portfolio on an on-going basis. If they determine that there is a need for additional capacity and/or energy, the Companies will procure any needed firm products through direct negotiations with counterparties or a competitive procurement process.

- Any proposed purchases of a duration greater than three years would be submitted to the Commission for approval in an IRP filing or Amendment.

- The Companies will continue to make purchases and sales to optimize the value of the overall supply portfolio for the benefit of their bundled retail customers.

- The Companies will monitor their renewable portfolio on a continuous basis to determine whether any additional renewable energy and PCs are required to ensure compliance with the RPS.

Each element of the proposed power procurement plan is discussed below.

C. OPEN POWER POSITIONS

1. CAPACITY AND ENERGY POSITIONS

As discussed in Section 2.B (Capacity Requirement), the Companies have a 1,020 MW open capacity position in 2026 and 1,926 MW in 2027. Therefore, the Companies plan to continue the four-season laddering strategy for the procurement of capacity to close the open position. This is similar to the strategy used for the procurement of physical natural gas. Specifically, and for example, the Companies plan to close up to the 2026 summer open position, a portion of the 2027 summer open position, and a portion of 2028 in the first and third quarters of 2026 through purchases of energy and/or capacity executed through a competitive procurement process, subject to the availability of conforming bids and the willingness of suppliers to accept reasonable commercial terms. A schedule of procurement activity under the four-season laddering strategy is set forth in Figure ESP-35 below.

FIGURE ESP-35
PERCENTAGE OF REMAINING OPEN POSITION THAT IS CLOSED IN EACH TRANSACTION PERIOD

Incremental transaction	Delivery				
	Summer 2025	Summer 2026	Summer 2027	Summer 2028	Summer 2029
Q3 2023	25%				
Q1 2024	25%				
Q3 2024	25%	25%			
Q1 2025	25%	25%			
Q3 2025		25%	25%		
Q1 2026		25%	25%		
Q3 2026			25%	25%	
Q1 2027			25%	25%	
Q3 2027				25%	25%
Sum	100%	100%	100%	75%	25%

The seasons in the four-season laddering strategy align the closure of the open power position with the seasonal procurement of physical natural gas. The magnitude of the open power position will be determined prior to each transaction cycle using the latest approved forecasts and energy supply availability schedules. For a given initial open position, procurement quantities should be approximately equal in each of the four seasons.

As discussed in Section 2.C (Energy Requirements), the Companies will continue to seek to execute short-term and forward purchases when economic or needed to serve native load. The Companies can meet the energy requirements of their customers with existing generation, forward products (such as call options or forward block power), and daily and/or real-time purchases.

The Companies' short-term energy requirements can vary due to factors such as: 1) changes in fuel and purchased power prices; 2) frequency and duration of planned and forced outages; and 3) changes in expected weather and load requirements. Shifts in gas and market energy prices may cause the Companies to run their generation facilities more or less often than projected (*i.e.*, it may become more economic to self-generate at a greater level than was expected or to buy more power in the open market than was anticipated). Unscheduled plant outages impact plant availability, and real-time changes in weather can impact the Companies' loads. These factors may significantly change electric generation requirements, resulting in unanticipated changes in natural gas usage.

As in the past, the Companies will monitor and continuously adjust their power portfolio in order to optimize the value of their assets for the benefit of bundled retail customers. If the Companies determine a need for additional capacity and/or energy above what is being projected in this ESP filing, they will procure required firm products using direct negotiations with counterparties as well as competitive procurement processes. Any proposed power purchases of greater than three years' duration will be submitted to the Commission for approval in an IRP filing or an IRP amendment. To the extent the Companies have a long position, they will survey the market to identify sales opportunities.

Load requirements and system parameters may change subsequent to preparation and filing of this ESP. Consequently, it is possible the requirement for firm products may also change sometime during the forecast period. As a general policy, should firm power products be required (or subsequently change), the Companies may issue RFPs to fill those short positions. The selection of products to fill open capacity and energy requirements will be based on a detailed evaluation of actual bids received. All responses will be evaluated at the time of the RFP process to ensure an appropriate portfolio is selected based on the then-current availability and price of products being offered. This evaluation will ensure that any contracts executed provide the least-cost option for necessary capacity and energy requirements, while minimizing price volatility and maintaining required system reliability.

2. POTENTIAL PRODUCTS

The products typically available to fill any short capacity and energy positions are as follows:

- *Call Options (Fixed or Heat Rate)* – Options have the advantage of flexibility. The buyer of the option has the right, but not the obligation, to buy an agreed-upon quantity of energy at a certain time in the future and at a specified price. In exchange for this flexibility to exercise or not exercise the option, a premium is paid to the seller up front. This payment only covers the right to exercise the option. An additional payment is paid to the seller each time the option is exercised. If the option is exercised, the buyer pays the seller the "strike price." Generally, the strike price is either a fixed price or it is calculated by multiplying a fixed heat rate by a designated gas index for the day of delivery. Out-of-the-money options are likely not to be exercised due to their high strike price but serve as additional available capacity that can be called upon if necessary.

Typically, the Companies schedule energy deliveries in accordance with WECC scheduling procedures. These procedures call for the buyer of the option to exercise its right to the energy on a day-ahead basis for delivery the next scheduling day. When exercised, the purchase is for the full capacity amount and for the time of day that was contracted e.g., on-peak, super-peak, etc.

- *Standard Firm Energy* – The price and quantity of these products are mutually agreed to between buyer and seller in advance, and the energy is "must take" over the period for which the contract is executed. In the western U.S., standard firm energy is typically transacted under WSPP Service Schedule C.

- *Unit Contingent Products* – The price and quantity of these products are mutually agreed to between buyer and seller in advance, and subject to generator availability the energy is "must take" over the period for which the contract is executed. In the event of a failure to perform due to forced outage from the sourcing generator, the seller is not subject to financial damages. Unit contingent power transactions are often executed under WSPP Service Schedule B.

The Companies issue RFPs or negotiate directly with counterparties to fill requirements and also monitor the products and prices that are available on trading platforms. Products are modeled using an electric system production simulation model to determine which supply options best fit with the load requirements and available resources in a least-cost manner.

3. RETAIL PRICE VOLATILITY

The Companies have controlled their exposure to the capacity component of market price volatility by building and contracting for efficient generation. The Companies will have firm generation and purchased power resources that total between 8,328 MW and 10,501 MW for the summer of 2026, and between 8,382 MW and 10,199 MW for the summer of 2027 (for more details see figure ESP 5.) Open position exposure to the wholesale purchase power market presents the greatest risk of retail price volatility. The Companies' proposed power procurement strategy is intended to mitigate that risk.

4. RELIABILITY

The degree of reliability of a portfolio is directly proportional to the level of a secured commodity under the portfolio. In general, as the percentage of the portfolio that is open increases, reliability declines. Conversely, as the percentage of the portfolio that is closed increases, reliability improves.

As described in Section 2.B, the Companies developed a 12.5 percent PRM in the 2024 Joint IRP. The Companies' 12.5 percent PRM provides a prudent level of assurance that reliable supplies will be available in the event of currently unanticipated conditions, such as extreme weather conditions and forced outages on generation.

5. COMMERCIAL VIABILITY

As noted in recent filings, changes in climate, weather, resource variability, and market condition are impacting the western energy markets, requiring the Companies and stakeholders to reevaluate established practices to ensure sufficient capacity to meet peak demands during the summer. While the Companies have taken great strides in recent years to address the variability of renewable resources and their contribution to resource adequacy by enacting a new method of evaluating the hour with the largest open position in the ESP, updating the Effective Load Carrying Capability ("ELCC") in the IRP, and updating the PRM, addressing changes in weather through the use of new trended weather load forecasts, as well as taking steps to reduce the open position in the IRP in response to concerns about market availability, the concern and focus remain on the uncertain availability and deliverability of market capacity and energy.

As discussed generally in part C.1 of this Section, the Companies will continue to monitor and continuously adjust their power portfolio in order to optimize the value of their assets for the benefit of bundled retail customers. In addition, the Companies will continue to evaluate supply options for potential IRP filings that will mitigate the risk associated with this growing market uncertainty.

SECTION 5 – GAS PROCUREMENT PLAN

The Companies' gas procurement plan includes a physical gas procurement plan, a gas transportation plan, and a gas hedging plan.

A. PHYSICAL GAS PROCUREMENT PLAN

The Companies employ a four-season laddering strategy for physical gas purchases, in 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. As described in this ESP Update filing, the Companies are proposing to continue to follow the physical gas procurement strategy reviewed and approved in Docket No. 09-07003.

Figure ESP-36 reflects the historic and planned implementation of the physical gas acquisition strategy.

FIGURE ESP-36
PHYSICAL GAS ACQUISITION STRATEGY

	Delivery								
Incremental Transaction	Summer '25	Winter '25-'26	Summer '26	Winter '26-'27	Summer '27	Winter '27-'28	Summer '28	Winter '28-'29	Summer '29
Q1 '23									
Q3 '23	25%								
Q1 '24	25%	25%							
Q3 '24	25%	25%	25%						
Q1 '25	25%	25%	25%	25%					
Q3 '25		25%	25%	25%	25%				
Q1 '26			25%	25%	25%	25%			
Q3 '26				25%	25%	25%	25%		
Q1 '27					25%	25%	25%	25%	
Q3 '27						25%	25%	25%	25%
Sum	100%	100%	100%	100%	100%	100%	75%	50%	25%

Note: Winter includes the months of November through March and Summer includes the months of April through October.

Additionally, the Companies monitor the natural gas portfolio monthly, weekly, and daily. The Companies will make short-term purchases and sales for balancing and optimization activities for the natural gas portfolio based on the needs of the system. This practice will be continued over the ESP Update period.

The Companies continually evaluate their list of approved gas supplier counterparties and adjust as necessary to balance the objectives of minimizing the cost of supply, minimizing retail price volatility and maximizing the reliability of supply. As the Companies go out for longer term gas supplies, there may be two identifiable issues which continue to require monitoring. The two items, already part of the Companies' risk management processes, are:

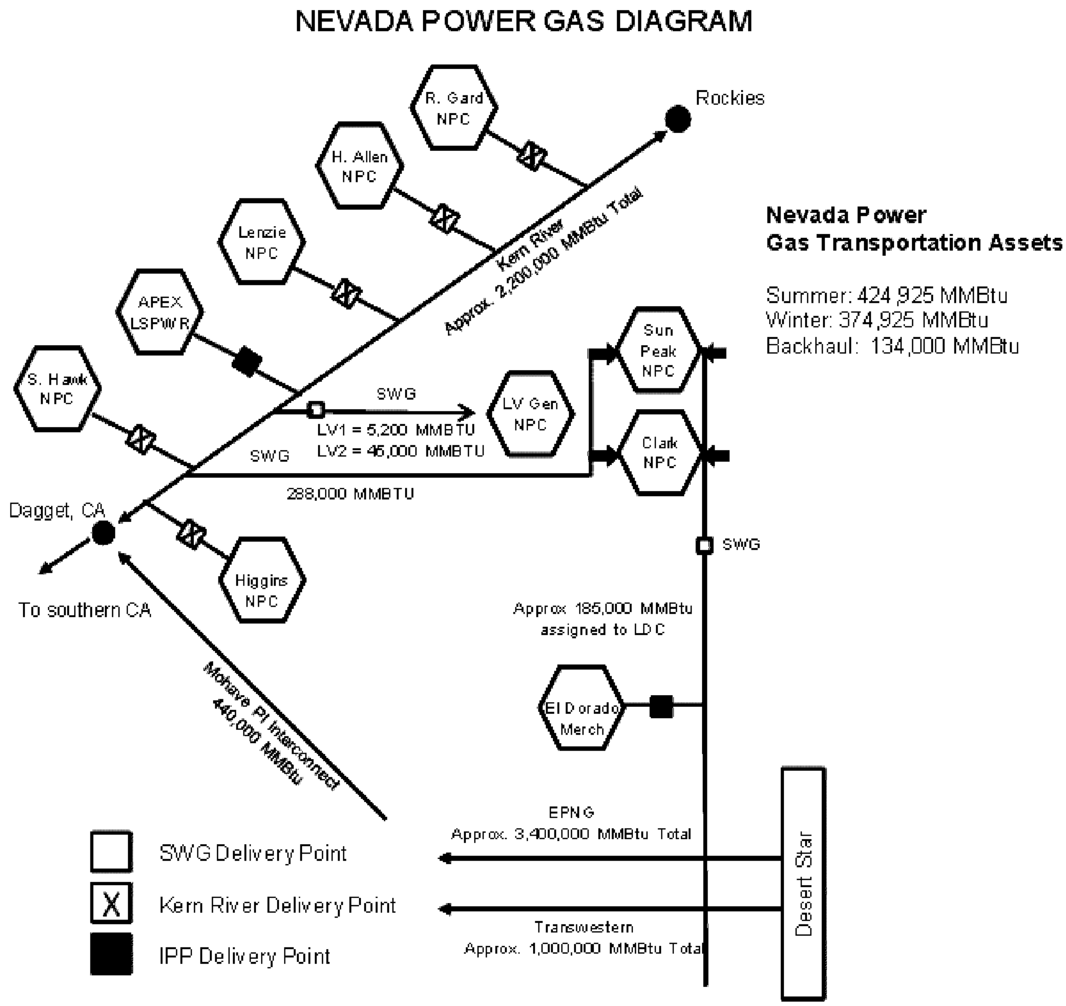
- *Counterparty performance risk*: Given that the natural gas commodity industry is in constant change with gas marketers, gas producers, and commodity trading companies entering into, merging, and exiting the physical gas transaction marketplace, the Companies will continue to monitor counterparty activity in order to have adequate assurance that the business entity with the obligation to provide the physical commodity is able to perform per the terms and conditions of the agreement.

- *Credit Management*: The Companies recognize a need to be able to manage both credit exposure from any one specific counterparty, as well as potential collateral provided to any one counterparty. While utilization of index-priced transactions should serve to minimize both potential counterparty exposure and potential counterparty collateral requirements, these exposures are continually monitored to prevent any future contract performance misunderstandings. The Companies continue to monitor such exposure risks through existing policies and procedures.

B. GAS TRANSPORTATION PLAN

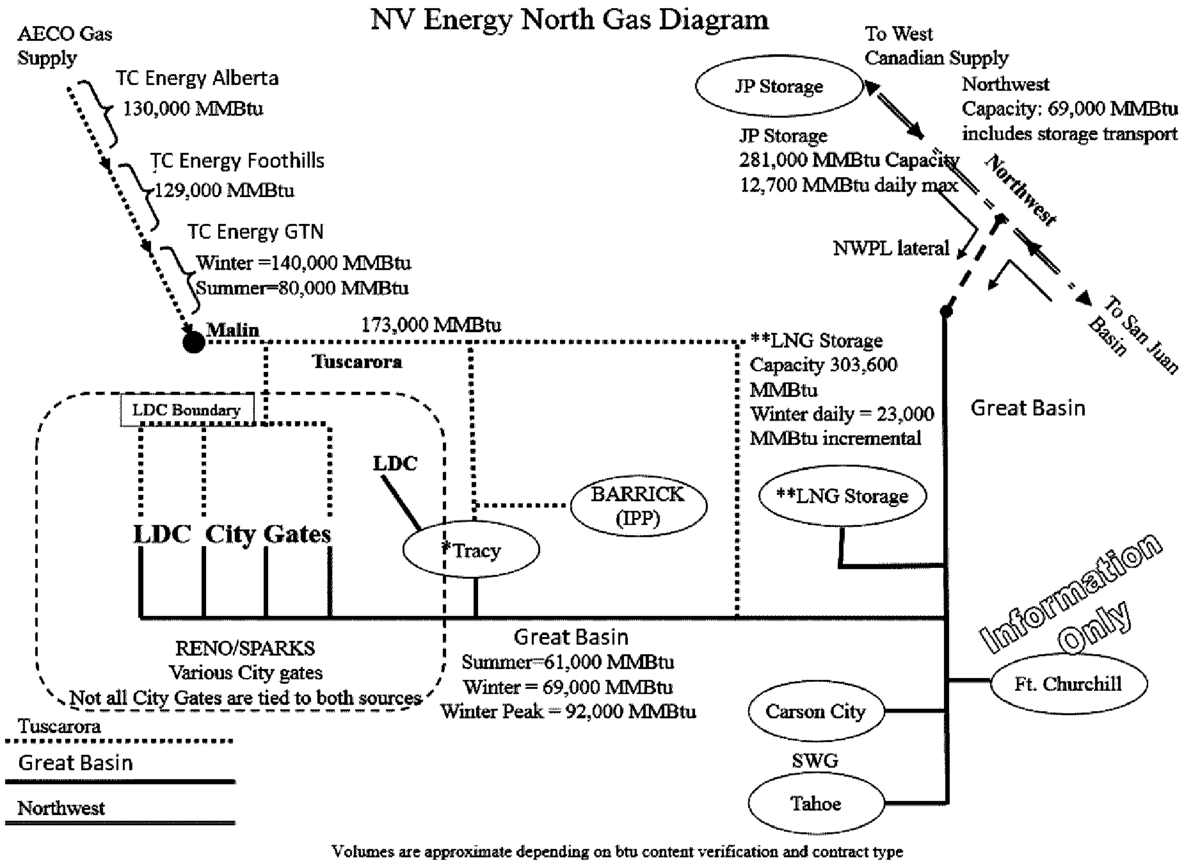
The Companies have access to the dominant supply basins serving the Pacific Northwest and the Desert Southwest per their existing firm gas transportation service agreements. These gas supply basins are the Rocky Mountain Basin, the Permian Basin, the San Juan Basin, British Columbia, Western Canada Sedimentary Basins, as well as California gas supply. The gas transportation facilities that are available to move gas from the supply basins to Nevada Power's and Sierra's service territories are shown in Figures ESP-37 and ESP-38, respectively.

FIGURE ESP-37
NEVADA POWER UPSTREAM PIPELINE SUPPLY



Nevada Power takes delivery of natural gas from interstate pipeline Kern River, which connects 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.

FIGURE ESP-38
SIERRA UPSTREAM PIPELINE SUPPLY



Sierra takes delivery of natural gas from two interstate pipelines, Great Basin and Tuscarora. Great Basin receives gas supplies upstream and downstream from Northwest Pipeline, 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 GTN, near Malin, Oregon, which is connected to the gas producing regions of Western Canada Sedimentary Basin Alberta through TC Energy's pipeline system. The gas supply source for Malin gas is predominantly in the Province of Alberta, Canada. TC Energy's Alberta pipeline system carries the gas commodity from the AECO producing areas of Canada to the Alberta/British Columbia border. There, TC Energy's Alberta system interconnects with TC Energy's Foothills system, which transports gas to TC Energy's GTN system at the U.S./Canadian border near Kingsgate, Idaho. GTN interconnects with Tuscarora near Malin.

Figure ESP-39 lists Nevada Power's existing gas transportation service agreements.

FIGURE ESP-39
NEVADA POWER NATURAL GAS TRANSPORTATION SERVICE AGREEMENTS

Nevada Power Company d/b/a NV Energy
Gas Transportation Agreements

Contract Type	Counterparty	Contract #	Termination Date (as of 7/1/2025)	Maximum Daily Quantity (MMBTUs) Annual	Winter	Summer	Comments
TSA	Kern River	20027	4/30/2028	75,000			
TSA	Kern River	20028	4/30/2028			50,000	
TSA	Kern River	20023	4/30/2032	12,500			
TSA	Kern River	20012	9/30/2031	10,350			
TSA	Kern River	20013	9/30/2031	11,075			
TSA	Kern River	1830	9/30/2031	266,000			Forward haul
TSA	Kern River	1617	9/30/2031	134,000			Back haul
Facilities	Kern River	Higgins Facility Charge	12/31/2039				No Volume
TSA	SW Gas	21016	4/30/2027	288,000			
TSA	SW Gas	21011	Month to Month			5,200	
TSA	SW Gas	21088	7/31/2026	45,000			

Nevada Power currently holds year-round contracts for firm forward haul gas transportation rights on Kern River totalling 374,925 MMBtu/day, with an additional 50,000 MMBtu/day in the summer that increases the maximum daily quantity to 424,925 MMBtu/day from April through October to serve a large portion of its overall daily natural gas needs. Nevada Power holds rollover rights under the Kern River tariff, provided Nevada Power is willing to continue under the terms and conditions specified therein. In addition, Nevada Power has a long-term agreement with Kern River for back haul capacity of 134,000 MMBtu/day. Nevada Power may procure Topock-sourced gas for re-delivery into Kern River at Daggett, California.

Gas supplies for Nevada Power's Harry Allen, Chuck Lenzie, Higgins and Silverhawk plants are delivered directly by Kern River. The gas-fired units at Edward W. Clark Generating Station and Sun Peak Generating Station receive gas delivered under a 288,000 MMBtu/day transportation service agreement with Southwest Gas Corporation ("Southwest"). The transportation agreement with Southwest provides for receipt of Kern River supplies, as well as limited quantities of gas from sellers off the El Paso Natural Gas Company ("El Paso") and/or Transwestern Pipeline Company ("Transwestern") pipelines south of Las Vegas (if Southwest Gas is not using its capacity rights to serve its own requirements). As part of the acquisition of Las Vegas Generating Station Units 1 and 2 in 2014, Nevada Power retained the gas transportation service agreements (LV Station Unit 1 - 5,200 MMBtu/day and LV Station Unit 2 45,000 MMBtu/day) with Southwest. The primary term for the LV Station Unit 2 contract with Southwest was extended through July 31, 2026.

Nevada Power meets at least once a year with Kern River to review the prior year's operations, discuss upcoming maintenance plans, and review potential expansions.

Nevada Power proposes to maintain its current natural gas transportation portfolio. As detailed in Section 2.E, sponsored by Company witness Mr. Charles McCutchen, Nevada Power's daily gas usage requirements during the summer exceeds the current contracted capacity with Kern River. Nevada Power has adequately closed prior firm gas transportation open positions by purchasing delivered natural gas (the gas commodity bundled with gas transport) 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.

Figure ESP-40 lists Sierra's existing gas transportation service agreements.

FIGURE ESP-40
SIERRA NATURAL GAS TRANSPORTATION SERVICE AGREEMENTS

Sierra Pacific Power Company d/b/a NV Energy
Gas Transportation and Storage Agreements

Contract Type	Counterparty	Contract #	Termination Date (as of 7/1/2025)	Units	Maximum Daily Quantity Annual	Winter	Summer
TSA							
	TC Energy - Alberta System						
		2010-447962	10/31/2026	GJ/Day	18,583		
		2010-447963	10/31/2026	GJ/Day	92,918		
		2010-447964	10/31/2026	GJ/Day	25,993		
					137,494		
	TC Energy - Foothills System						
		SIER - 9976	10/31/2026	GJ/Day	32,444		
		SIER - 9987	10/31/2026	GJ/Day	2,143		
		SIER - 9988	10/31/2026	GJ/Day	5,572		
		SIER - 9994	10/31/2026	GJ/Day	16,220		
		SIER - 9999	10/31/2026	GJ/Day	10,920		
		SIER - 10009	10/31/2026	GJ/Day	866		
		SIER - 9991	10/31/2026	GJ/Day	26,233		
		SIER - 10000	10/31/2026	GJ/Day	10,000		
		SIER - 10001	10/31/2026	GJ/Day	15,826		
		SIER - 10002	10/31/2026	GJ/Day	15,807		
					136,031		
	TC Energy - GTN						
		F-02842	10/31/2029	MMBTU/Day		60,000	30,000
		F-02843	10/31/2029	MMBTU/Day		20,270	10,000
		F-07027	4/30/2031	MMBTU/Day		20,000	
		F-07328	10/31/2029	MMBTU/Day	14,000		
		F-07370	10/31/2035	MMBTU/Day	15,000		
		F-07371	10/31/2035	MMBTU/Day	10,099		
		F-07567	10/31/2035	MMBTU/Day	800		
					39,899	100,270	40,000
	Northwest Pipeline						
		10046	6/30/2026	MMBTU/Day	59,696		
		10061	3/31/2026	MMBTU/Day	9,000		
					68,696		
	Great Basin Gas Transmission						
		F-29	11/30/2029	MMBTU/Day		68,696	61,044
		F-32	3/31/2030	MMBTU/Day		23,000	
						91,696	61,044
	TC Energy - Tuscarora						
		F001	12/31/2032	MMBTU/Day	105,730		
		F019	12/31/2032	MMBTU/Day	10,000		
		F024	12/31/2032	MMBTU/Day	5,661		
		F025	12/31/2032	MMBTU/Day	5,690		
		F030	12/31/2032	MMBTU/Day	5,722		
		F097	9/30/2030	MMBTU/Day	40,000		
		359	9/30/2030	MMBTU/Day	780		
					173,583		
Storage							
	Northwest Pipeline						
		126344 Storage Capacity	3/31/2046	MMBTU	281,242		
		126344 Storage Withdraw	3/31/2046	MMBTU/Day	12,687		
	Great Basin Gas Transmission						
		S-6 LNG Stor Cap	3/31/2030	MMBTU	308,604		
		S-6 LNG Daily Del Cap	3/31/2030	MMBTU/Day		23,000	

Gas Transportation into Tuscarora. In Canada, Sierra currently holds year-round firm transportation contracts on TC Energy's Alberta system totaling 137,494 GJ/day. Downstream from TC Energy Alberta, Sierra holds year-round firm transportation contracts on TC Energy's Foothills system totaling 136,031 GJ/day. Downstream from TC Energy Foothills, Sierra holds both year-round and seasonal firm transportation contracts on TC Energy's GTN pipeline for 80,000 MMBtu/day and 140,000 MMBtu/day, respectively. Sierra holds 173,583 MMBtu/day of year-round firm transportation contracts on TC Energy – Tuscarora.

Gas Transportation into Great Basin. Sierra holds year-round firm transportation contracts on Northwest Pipeline totaling 68,696 MMBtu/day. On Great Basin, Sierra holds seasonal firm transportation contracts. The winter totals 91,696 MMBtu/day and the summer totals 61,044 MMBtu/day.

Other Transportation and Storage. Sierra also has storage assets along both Northwest Pipeline and Great Basin. The Northwest Pipeline storage is located at the Jackson Prairie facility and allows for unlimited injection/withdrawal cycles subject to then-current mainline pipeline operating conditions. Sierra's total firm storage rights at Jackson Prairie are just over 281,000 MMBtu and come with about 12,600 MMBtu of firm daily injection/withdrawal rights. Each year Sierra evaluates opportunities to enter into an asset management agreement to further optimize these assets. The Great Basin storage is located at the H.G. Laub LNG plant and allows for approximately 304,000 MMBtu of LNG storage capacity that comes with up to 23,000 MMBtu of firm daily withdrawal rights, including firm transport to the LDC service territory; however, the LNG supply is only available during the winter season.

Sierra will soon be adding transportation capacity from Ruby and Pinyon, which will supply natural gas to the Valmy Plant. These transportation service agreements are expected to be executed in Q4 of 2025.

Sierra meets at least once a year with all of the interstate pipeline companies to review the prior year's operations, discuss upcoming maintenance plans, and review potential expansions.

Sierra proposes to maintain its current natural gas transportation portfolio. Many of Sierra's contracts have evergreen clauses and can be renewed for successive one-year extension periods. Given the results of the analysis detailed in Section 2.E, sponsored by Company witness Mr. Charles McCutchen, the need to ensure reliability remains a critical focus of the LDC. Additionally, with the requirement in NAC § 704.9099(3) to maximize the reliability of fuel supply over the term of the energy supply plan, Sierra proposes to continue to renew these contracts on an annual basis to ensure firm deliveries of gas supplies. Sierra will also 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.

C. RECOMMENDED GAS HEDGING PLAN

The Companies are seeking Commission approval of a hedging strategy for gas seasons 2026-2027 that uses no financial or fixed physical products to hedge their natural gas price exposure. If a change in strategy is warranted or necessary, the Companies will bring forward an ESP amendment or future ESP update for Commission approval.

SECTION 6 – COAL AND VALMY CLOSURE

A. CURRENT COAL PURCHASE & TRANSPORTATION AGREEMENTS

Currently, Sierra has coal purchase and transportation agreements in place to provide enough supply through end of 2025. Sierra will continue to monitor Valmy's unit operations, coal stockpile levels, coal burn forecast updates, and scheduled must run conditions. In line with the goal of providing coal shipments that enable the plant to operate efficiently while meeting all required environmental regulations, coal quality parameters of all candidate coal sources are screened and reviewed with the plant.

B. VALMY CLOSURE

As described in the Generation Section of the narrative in the 2024 Joint IRP, North Valmy's landfill is subject to the closure requirements in the federal Coal Combustion Residuals ("CCR") Rule. The landfill is also regulated by the Nevada Division of Environmental Protection ("NDEP") as a Class III landfill. The CCR Rule requires that closure must commence two years after the landfill received the last receipt of waste, either CCR or non-CCR waste, or two years after the last CCR was removed for beneficial use. Based on this requirement and following prudent utility practices, retirement and decommissioning of facilities that handled coal, and ash residuals, or are no longer necessary to operate Valmy following conversion to natural gas operation will be completed such that the onsite landfill can be utilized for disposal, closed, and enter post-closure care monitoring under the CCR Rule and state permit requirements.

As part of the natural gas conversion, a decommissioning plan will be developed to determine what areas can be de-energized, separated, decontaminated, demolished, and/or remediated. Planning will include a facility regulated materials survey, utility survey for re-routes or isolations, landfill survey and related activities to support planning and engineering. Facility-wide industrial cleaning will be completed to remove latent coal and ash, particularly in areas that were part of coal conveyance or ash conveyance systems. Any onsite disposal while the landfill is allowed to operate will help to diminish future costs for offsite disposal after the onsite landfill is closed. General areas expected to be part of this decommissioning include the coal yard area, coal conveyance systems, ash handling equipment, rail unloading areas (e.g., unloading trestle, thaw shed), and diesel start-up related storage and equipment. Soil or groundwater remediation may potentially be required in those areas where coal and diesel fuel were handled. Once these activities are complete,the onsite landfill will be closed, and post-closure monitoring will commence per CCR regulations and state permit requirements.

SECTION 7 – RISK MANAGEMENT STRATEGY

A. ELEMENTS OF THE STRATEGY

Energy risk management involves the development and implementation of strategies to appropriately balance cost, risk, and reliability concerns. The Companies' energy supply risk management activities are the responsibility of the Resource Planning & Analysis Organization, which is described in the direct testimony of Ms. Janet Wells, the Risk Control Organization, which is described in the direct testimony of Mr. Adrian Cacuci, and the Resource Optimization Organization which is described in the direct testimony of Mr. Michael Holland.

Four areas are involved in the Companies' risk management and control processes:

1) **Risk Committee**. The Risk Committee is responsible for overall policy direction of the Companies' risk control activities and serves as the mechanism through which the Chief Executive Officer and senior management are kept apprised of inherent company-wide risks. The Risk Management and Control Policy (Technical Appendix RM-1) details the membership and specific responsibilities of the Risk Committee.

2) **Energy Supply**. Energy Supply, under direction of the Vice President, Integrated resource Planning, Vice President-Generation and the Vice President, Resource Optimization, are responsible for the generation production, delivery and optimization of fuel and wholesale power transactions.

3) **Risk Control**. The Risk Control function is responsible for monitoring compliance with established risk policies and associated procedures. All omissions and exceptions will be reported promptly to the Risk Committee.

4) **Credit Risk Management**. Credit risk is defined as the possibility that a counterparty will be unable or unwilling to timely fulfill its financial or physical obligations to the Companies because of the counterparty's financial condition. Credit Risk Management is responsible for managing and mitigating the Companies' credit risk exposures associated with energy and service delivery transactions. The Credit Risk Management and Control Policy is included as Technical Appendix RM-3.

The Risk Committee has several key responsibilities, including:

- Assessing the appropriateness of the Companies' energy supply risk management and control activities and making recommendations for modifications to existing risk policies;

- Approving changes and exceptions as designated in specific sections of the risk policies and ensuring the ongoing availability of procedures required to implement those policies or any changes to them;

- Assessing the systems required to monitor, record, and report on the risks inherent in the Companies' energy supply related activities and making recommendations for improvements to existing risk policies;

- Approving ESPs, ESP updates and any exceptions to these plans;

- Reviewing all transactions requiring exceptions to the applicable policies and procedures;

- Reviewing all energy procurement and sale transactions that are not transacted in accordance with the ESP prior to the submission for approval of such transaction to the President;

- Reviewing all violations of notification thresholds and processes established under the risk policies, approving or recommending for approval remedies of the violations, and monitoring progress of such remedies; and

- Assigning the completion of any other activities to guide the overall policy direction of the Companies' energy risk management and control efforts.

Resource Planning & Analysis develops and maintains ongoing energy supply and risk management plans to systematically evaluate supply portfolio alternatives against a set of specific criteria monitored and reported by Risk Control. These criteria include transaction approval limits, test period mark-to-base, value at risk, and credit risk limits. This risk management approach includes: (1) the IRP covering the long-term resource and infrastructure needs and the plans to meet those needs; and (2) the ESP covering in detail the intermediate-term resource requirements and the plans to fulfill those requirements. Resource Optimization executes transactions that are consistent with the approved IRPs and ESPs. Material transactions that deviate from the approved plans are not executed without the prior approval of the Risk Committee.

Risk Control measures the Companies' energy portfolio exposures and compares measurements to the approved exposure notification thresholds. Reports are prepared to identify, track, and report compliance with the Companies' risk policies.

Credit Risk Management mitigates risk of the organization by reviewing potential transactions with counterparties to make sure they comply with credit limits. All potential transactions are reviewed to determine the counterparty's credit ratings, policy limits based on credit ratings, the current mark-to-market exposure of all current transactions, and whether the potential credit exposure calculations are within the company policy limits.

B. ELEMENTS OF THE STRATEGY APPLIED TO THE ENERGY SUPPLY PLAN

This ESP Update was prepared by the Resource Planning & Analysis Department, with additional input from the Rates & Regulatory, Renewable Energy & Origination, Generation, Resource Optimization, Revenue Requirements, Risk Control and Treasury groups.

The ESP Update is designed to achieve the objectives set forth in NAC § 704.9061 – minimizing the cost of supply, minimizing retail price volatility, and maximizing the reliability of energy supply over the term of the energy supply plan. However, it is not generally possible to minimize both cost and risk. For example, a completely open position may yield the lowest expected cost under certain assumptions, but it may carry significant risks associated with unforeseen events. Option contracts may eliminate the potential for retail price volatility, but the Companies may be required to incur a cost in order to compensate its counterparties for the price risk that has been shifted from the utility's customers to them. Thus, option contracts may not yield the lowest expected cost in all cases. The recommended strategies are designed to mitigate risk in the following respects:

Evaluation of Options. Risk minimization activities start with the planning process and the decisions for demand or supply options that are examined and eventually integrated into the Companies' IRP and ESP. Starting with the load forecast, the Companies establish customers' needs, including appropriate reserve margins. Once those needs are known, the options available to meet those needs are assessed. A part of that process is an examination of market fundamentals in the region, including the outlook for change over the planning horizon.

Reduce Reliance on Volatile Wholesale Energy Markets. As part of its longer-term risk management strategy and with a goal of reducing its exposure to volatility of the capacity portion (scarcity premiums) of the energy supply costs, the Companies pursue a strategy that relies on longer term power purchase contracts, and a multi-year laddering strategy.

Use of Competitive Procurement Processes. While the Companies have significantly reduced their open positions compared to previous years, they may issue a request for proposal if warranted to cover unanticipated needs at competitive costs. As part of the risk management plan, an economic analysis of the bid responses will be conducted and the selected options will be referred to the Resource Optimization Department and Renewable Energy and Origination for negotiation and contracting as appropriate.

C. SELECTION CRITERIA

The criteria used to select the Companies' risk management strategy are set forth in NAC § 704.9061 and include: cost of supply, retail price volatility, and reliability of energy supply.

D. EVALUATION CRITERIA

The Risk Committee reviews the Companies' forward power and gas positions on a regular basis. To the extent that circumstances dictate a change in the Companies' procurement strategies, the Risk Committee would review and approve the changes, as appropriate.

In general, the criteria used to evaluate the effectiveness of the risk management strategy include the criteria set forth in NAC § 704.9061 and the metrics that are monitored by the Risk Control organization, which include:

- Test period Mark-to-Base
- Value-at-Risk
- Portfolio below investment grade
- Portfolio weighted-average credit rating
- Counterparty credit limit on-going transactions
- Counterparty credit limit large transactions

The Companies acknowledge that they may deviate from an approved Energy Supply Plan or Energy Supply Plan Update in accordance with NAC § 704.9504 and accept the obligation to modify the strategy as conditions warrant.

SECTION 8 – 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 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.
- The plan optimizes the value of the overall supply portfolio of the utility for the benefit of its bundled retail customers.
- The plan 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 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. Based on results of the PLEXOS production cost forecasting model, Figure ESP-41 shows the estimated cost-to-serve for the recommended unhedged scenario under base, high, and low fuel and purchased power pricing scenarios.

FIGURE ESP-41
ESTIMATED COST TO SERVE (IN $000)

TOTAL FUEL AND PURCHASED POWER (F&PP) COSTS, EXCLUDING FIXED & VARIABLE OPERATIONS AND MAINTENANCE			
Year	Cost to Serve Assuming Low F&PP Prices ($000)	Cost to Serve Assuming Base F&PP Prices ($000)	Cost to Serve Assuming High F&PP Prices ($000)
2026	$1,400,451	$1,820,681	$2,328,161
2007	$1,495,396	$1,981,116	$2,670,463

The Companies also calculated the projected Base Tariff Energy Rates ("BTER") and Deferred Energy Accounting Adjustment ("DEAA") rates for 2026-2027 under the low, base, and high fuel and purchased power price forecasts. The projected BTER and DEAA rates, along with estimated carrying charges, are presented in Technical Appendix GAS-2.

The expected cost-to-serve and BTER remain within a reasonable band under the Companies' proposed procurement strategies. The ESP provides for the procurement of sufficient firm resources to ensure reliable service to retail customers.

The production cost, BTER, and DEAA calculations and analysis, show that this ESP Update balances the objectives of minimizing the cost of supply, minimizing retail price volatility, and maximizing the reliability of supply over the term of this plan.

This ESP Update optimizes the value of the overall supply portfolio of the utilities for the benefit of their bundled retail customers. The Companies will continue to monitor and adjust the power portfolio in order to identify and account for changes in load, cost, volatility, reliability, and other commercial or technical factors. Day-ahead, day-of, or month-ahead power purchases are expected to be made if there is an open position, or if system costs of decremental energy exceed the additional cost of market purchases. Similarly, day-ahead or day-of power sales are expected to be made as opportunities arise, including spot, fixed price, indexed agreements, or ancillary services products, as specified in the Energy Risk Management and Control Policy (Technical Appendix RM-2). The Companies also intend to continue to seek opportunities for forward sales of heat rate ("HR") call options and/or other products through direct negotiations with counterparties or the issuance of reverse RFPs.

This ESP Update does not contain any feature or mechanism that would impair the restoration of the creditworthiness of the utilities or would lead to a deterioration of the creditworthiness of the utilities. The Companies are able to finance this ESP Update without impairing their creditworthiness, assuming timely recovery under the Commission's current rate recovery mechanisms.

SECTION 9 – COMMISSION DIRECTIVES

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.

Copies of the meeting presentations for the Gas Hedging Workshop held during the last three quarters of 2024 and the first two quarters of 2025 are included as Technical Appendix GAS-1.