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24-05041

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SIERRA CLUB

October 18, 2024

Trisha Osborne
Assistant Commission Secretary
Public Utilities Commission of Nevada
1150 East William Street
Carson City, NV 89701

Re: **Sierra Club's Prepared Direct Testimony in Phase III of Docket No. 24-05041**

Dear Ms. Osborne,

Please find attached for filing the Public and Redacted Version of the Direct Testimony of Rose Anderson on behalf of Sierra Club in Phase III of the above-referenced docket. The Confidential portions of Ms. Anderson's testimony have been sent separately to the Commission Secretary in accordance with Nevada Administrative Code 703.5274, and will be made available upon request to parties that have signed the Protective Agreement in this matter.

Ms. Anderson's Direct Testimony contains information that NV Energy has requested be treated as confidential pursuant to the Protective Agreement executed between the parties in this proceeding, including the following:

- Certain information on pages 12, 15-16, 18-19, 24-25 of Ms. Anderson's Direct Testimony (which is identified in the Confidential version of these pages and redacted in the public version)
- Attachment RA-3 to Ms. Anderson's Direct Testimony (NV Energy's Confidential Responses to Sierra Club Data Requests in Docket No. 24-05041)
- Attachment RA-7 to Ms. Anderson's Direct Testimony (excerpt of NV Energy Confidential Workpaper, "2024 IRP – F&PP Figures")

In accordance with Nevada Administrative Code 703.5274(2)(c), Sierra Club requests that the Commission maintain the confidentiality of the above information for a five-year period.

Please let us know if you have any questions. Thank you.

Sincerely,

/s/ Patrick Woolsey

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Enclosures
cc: Parties of Record (via Email)

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2025-2044 Triennial Integrated Resource Plan and 2025-2027 Energy Supply Plan.	)))))	Docket No. 24-05041

Direct Testimony of Rose Anderson

On Behalf of Sierra Club

PUBLIC AND REDACTED VERSION

October 18, 2024

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LIST OF ATTACHMENTS

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q Please state your name and occupation.

A My name is Rose Anderson. I am a Principal Associate at Synapse Energy Economics. My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

2. Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

3. Q Please summarize your work experience and educational background.

A At Synapse, I review planning assumptions and modeling in utility integrated resource plans.

Before joining Synapse, I performed economic analysis at the Oregon Public Utility Commission and at McCullough Research, an energy economics consulting firm.

A copy of my current resume is attached as Attachment RA-1.

4. Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

5. Q Have you testified previously before the Nevada Public Utilities Commission?

A Yes. I have testified in NV Energy's Fifth Amendment to its 2021 Integrated Resource Plan, Docket No. 23-08015.

6. Q What is the purpose of your testimony in this proceeding?

A I evaluate Nevada Power Company and Sierra Pacific Power Company's (together, "NV Energy" or "the Company") proposals for the North Valmy Generating Station ("Valmy") in the Company's 2024 Integrated Resource Plan ("IRP"). Specifically, I analyze NV Energy's use of a must-run commitment status for Valmy Units 1 and 2 (the "Valmy Steam Units") and modeling of seasonal operations of those steam units.

I also discuss whether the Company could cease must-run at Valmy Units 1 and 2 without installing the new gas-fired combustion turbine ("CT") units that NV Energy is proposing at the Valmy site (the "Valmy CTs"), once transmission upgrades are completed and if industrial load growth is lower than expected.

Finally, I evaluate the Company's near-term industrial load forecast and whether the Company is adequately considering the possibility that load growth is lower than projected, and the resulting impact on the usefulness of the proposed Valmy CTs.

7. Q How is your testimony structured?

A In Section II, I summarize my findings and recommendations. In Section III, I provide background regarding the Valmy plant. In Section IV, I describe the Company's proposals for the Valmy site in the 2024 IRP and share my concerns and recommendations for additional protections to improve the value of the Company's plans for customers. In Section V, I discuss the Company's proposed Valmy CTs and how changes in the Company's large customer load forecast could affect the usefulness of the proposed Valmy CTs.

8. Q What documents do you rely upon for your analysis, findings, and observations?

A My analysis relies upon filings by NV Energy in this IRP, the Company's responses to discovery requests, the Company's Fifth Amendment to its 2021 IRP, and my testimony on behalf of Sierra Club in the Fifth Amendment to the 2021 IRP.[1]

II. FINDINGS AND RECOMMENDATIONS

9. Q Please summarize your findings.

A My findings are that:

a) NV Energy has not adequately studied whether, or to what extent, it will be able to end the ongoing must-run requirement at Valmy Units 1 and 2, even though the

[1] Direct Testimony of Rose Anderson on behalf of Sierra Club, Docket No. 23-08015 (Nev. Pub. Util. Comm'n Dec. 19, 2023) (excerpt provided in Attachment ["Attach."] RA-4).

Company's preferred portfolio includes the benefits of ending the must-run requirement at the Valmy Steam Units after 2028.

b) NV Energy has not taken any steps to plan for implementing seasonal operations at Valmy Units 1 and 2, even though the Company's IRP analysis shows that seasonal operation of the Valmy Steam Units will be economic once must-run operation is no longer needed. NV Energy has not planned for implementation of seasonal operations, and the Company has not communicated with Valmy co-owner Idaho Power about potential seasonal operations.

c) There is a great deal of uncertainty in the Company's near-term industrial load forecast and a substantial risk that NV Energy's projected industrial load growth will be lower than anticipated.

d) If expected load growth in the Carlin Trend Load Pocket does not materialize, it may be possible to cease the ongoing must-run requirement at Valmy Units 1 and 2 without installing the proposed Valmy CTs.

10. Q Please summarize your recommendations.

A Based on my findings, I offer the following recommendations:

a) NV Energy should provide a detailed technical explanation confirming that the proposed Valmy CT units will enable the Company to cease the ongoing must-run requirement at both Valmy Steam Units and to realize reductions in cost and pollution at those units similar to those shown in the 2024 IRP preferred portfolio.

b) Before the Commission grants approval of cost-recovery for the proposed Valmy CTs in any rate case, NV Energy should be required to provide a detailed technical explanation and analysis confirming that it will be able to realize the expected cost and pollution reduction benefits at the Valmy Steam Units by removing the must-run requirement during normal system conditions (when no local generation or transmission is experiencing an outage).

c) NV Energy should provide a detailed narrative explanation and analysis of the benefits, obstacles, and potential next steps toward implementing seasonal operations at the Valmy Steam Units as part of its next IRP amendment or before both units are converted to gas in 2026, whichever is sooner.

d) Because circumstances have changed since the approval of NV Energy's plan to retire the Valmy Steam Units in 2049, the Commission should require the Company to study the possibility of retiring the Steam Units earlier than 2049, especially if it installs the proposed Valmy CTs. Specifically, the Company should provide an updated retirement analysis that considers a variety of potential retirement dates within the next IRP update.

e) The Company should be required to notify the Commission immediately if any near-term large customer new load requests in Northern Nevada are cancelled or reduced. If the reduction in the load forecast is significant, it may justify further study of the Company's plans at the Valmy site, including the proposed Valmy CTs and investments in the Valmy Steam Units.

f) The Commission should direct NV Energy to provide alternate portfolios showing optimal resource plans if uncertain industrial load does not materialize. This should include the assessment of whether, under a lower industrial load forecast, the Company could both avoid the proposed Valmy CTs and end the must-run requirement at the Valmy Steam Units once the Greenlink West and Greenlink North transmission projects are in service.

III. VALMY BACKGROUND AND CONTEXT

11. Q Please describe the existing Valmy plant and its location in the Carlin Trend Load Pocket.

A The Valmy plant is a 522 megawatt ("MW") power plant located west of Battle Mountain, Nevada, with two coal-fired steam units, Units 1 and 2. The plant is co-owned by NV Energy and Idaho Power. NV Energy owns a 50 percent share of the plant's generating capacity, i.e. 261 MW. The steam units were built in 1981 and 1985, respectively. The Title V air quality permit for Valmy imposed a federally enforceable retirement date of December 31, 2028 for the coal-fired units.

Valmy is located in the Carlin Trend Load Pocket. The Valmy Steam Units (Units 1 and 2) are two of only three generators in that load pocket (the third is Newmont Mining Corporation's TS Power Plant). NV Energy has previously determined that at least two out of the three local generators must run at all times in order to avoid the risk of load shed in that load pocket.[2]

[2] Joint Application of Nevada Power Co. d/b/a NV Energy and Sierra Pacific Power Co. d/b/a NV Energy for approval of the Fifth Amendment to the 2021 Joint Integrated Resource Plan, Vol. 4, TRAN-5 at 1, Docket No. 23-08015 (Nev. Pub. Util. Comm'n Aug. 21, 2023) [hereinafter "5th Amendment to the 2021 IRP"] (excerpt provided in Attach. RA-5).

12. Q Please provide background on NV Energy's plans for the Valmy site prior to this docket.

A In NV Energy's Fifth Amendment to its 2021 IRP, Docket No. 23-08015, the Company made substantial changes to its plans for the Valmy Steam Units. NV Energy proposed to convert Valmy Units 1 and 2 from coal to gas by June 1, 2026, install selective catalytic reduction ("SCR") technology at both units, and extend the operating lives of those units from 2025 to 2049.[3] The converted Valmy Steam Units would be supplied with gas from the Pinyon Pipeline, a new gas pipeline that is currently being permitted and constructed to serve the site.[4]

In the Fifth Amendment to the 2021 IRP, the Company considered the possibility of installing two gas CTs at the Valmy site, but the preferred portfolio in that application did not include the Valmy CTs.[5]

13. Q Were all of the Company's requests for Valmy Units 1 and 2 in the Fifth Amendment to the 2021 IRP approved by the Commission?

A No. While the Commission approved NV Energy's plans to install SCR at the Valmy Steam Units, convert the units to gas, and amend the Supply Plan to operate the units through 2049,[6] the Commission did not approve the Company's other proposed capital investments to support continued operations of the Valmy

[3] Modified Final Order, 96 ¶ 207, 99 ¶ 215, Docket No. 23-08015 (Nev. Pub. Util. Comm'n Apr. 9, 2024) [hereinafter "Docket No. 23-08015 Final Order"].

[4] 5th Amendment to the 2021 IRP, Vol. 1, Exhibit ("Ex.") A – Narrative at 62.

[5] *Id.*, Vol. 1, Ex. A – Narrative at 148.

[6] Docket No. 23-08015 Final Order, 96 ¶ 207.

Steam Units through 2049, finding that the details of those additional investments were too uncertain at the time.[7]

14. Q Please describe the recent reliability must run ("RMR") decision for operation of the Valmy Steam Units.

A In July 2023, the Company issued an internal report which found that at least one Valmy steam unit must be kept online as an RMR unit at all times for system reliability.[8] RMR status is a determination made by NV Energy that indicates that for system reliability purposes, a unit must be kept running at all times.

There are only three generating units serving the Carlin Trend Load Pocket: the two Valmy Steam Units and the nearby TS Power Plant ("TSPP") owned by Newmont Mining Corporation. The Company's internal report states that if only one out of the three units are operational, an unplanned outage at that unit is expected to cause around 300 MW of load loss.[9] Therefore, the report states that one of the two Valmy Steam Units must be in RMR status when the TSPP is online. When the TSPP is offline, the report found that both Valmy Steam Units must be placed into RMR status in order to "manage risks associated with an undervoltage load shed condition impacting the Carlin Load Trend area."[10]

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[7] *Id.* at 96 ¶ 207, 99 ¶ 215.

[8] 5th Amendment to the 2021 IRP, Vol. 4, TRAN-5 at 1.

[9] *Id.*, Vol. 4, TRAN-5 at 5.

[10] *Id.*, Vol. 4, TRAN-5 at 1.

15. Q Please describe the Regional Haze Rule and the Good Neighbor Plan, and how they may impact the Valmy Steam Units.

A The U.S. Environmental Protection Agency's ("EPA") Regional Haze Rule requires states to reduce nitrogen oxide ("NO_X") emissions to improve visibility at parks and wilderness areas.[11] The EPA's Good Neighbor Plan regulates ground-level ozone, or smog, caused by NO_X emissions.[12] Both regulations may result in the need to reduce emissions at the Valmy Steam Units through emissions control technology or reduced generation at those units.

The Nevada Division of Environmental Protection ("NDEP") is currently revising Nevada's State Implementation Plan ("SIP") for the Regional Haze Rule's Second Planning Period.[13] The Good Neighbor Plan has been temporarily stayed and is not currently being implemented by the EPA in Nevada. NV Energy states that it is uncertain how various factors will "affect the timing of implementation of the Good Neighbor Plan in Nevada."[14] Regulatory uncertainty surrounding the Good Neighbor Plan and Regional Haze Rule increases the potential risks associated

[11] EPA's Regional Haze Rule, 40 C.F.R. § 51.308.
[12] Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023), *available at* https://www.govinfo.gov/content/pkg/FR-2023-06-05/pdf/2023-05744.pdf.
[13] *See* Nevada Power Co. d/b/a NV Energy and Sierra Pacific Power Co. d/b/a NV Energy Joint Application for Approval of 2024 Joint Triennial Integrated Resource Plan (Nev. Pub. Util. Comm'n May 31, 2024) [hereinafter "2024 IRP Application"], Vol. 3, Direct Testimony of Mathew Johns at 4.

[14] *Id.*, Vol. 8 at 24; *see also id.*, Vol. 3, Direct Testimony of Mathew Johns at 5.

with the installation of SCR at the Valmy Steam Units if a less expensive technology is ultimately required under those regulations.

IV. NV ENERGY'S PLAN FOR THE VALMY SITE IN THE 2024 IRP

16. Q Please describe NV Energy's proposals for CTs at the Valmy site in this IRP.

A In NV Energy's 2024 IRP application, the Company proposes to construct two new gas-fired simple-cycle CT units at the Valmy site, with a total capacity of 411 MW, in addition to associated transmission infrastructure.[15] The proposed Valmy CT units would have an in-service date of 2028 and an estimated cost of $573.3 million.[16] The proposed Valmy CT units would use the Pinyon Pipeline that is currently going through permitting and which will support the planned conversion of the existing Valmy Steam Units to gas.[17]

17. Q How does the Company support its proposal to install CTs at the Valmy site?

A The 2024 IRP includes a scenario that shows approximately $18 million in reduced 20-year system PWRR by adding the proposed Valmy CTs to the system.[18] The Company concludes that its preferred portfolio, which includes the proposed Valmy CTs, is the lowest-cost case out of the four combination cases studied in the IRP.[19] The Company asserts that the Valmy CTs have "fast start

[15] 2024 IRP Application, Vol. 8 at 175.

[16] *Id.*, Vol. 8 at 17-18, 21; *see also id.*, Vol. 3, Direct Testimony of John Lescenski at 6.

[17] *Id.*, Vol. 3, Direct Testimony of John Lescenski at 7.

[18] *Id.*, Vol. 8 at 231.

[19] *Id.*, Vol. 8 at 237.

and fast ramp capabilities" that would "enable the retirement of the 'must -run' requirement currently applied to Valmy Units 1 and 2."[20] The IRP also states that the proposed Valmy CTs reduce the Company's need to rely on the market to meet forecast peak capacity needs.[21]

18. Q Please describe how the Company's plans for the Valmy Steam Units have changed in the 2024 IRP.

A As discussed above, in the Fifth Amendment to NV Energy's 2021 IRP the Commission approved NV Energy's plans to convert the Valmy Steam Units to gas, to install SCR at the units to control NO_X, and to amend the supply plan to include continued operation of Valmy Units 1 and 2 on gas through 2049.[22] In the Fifth Amendment, the Valmy Steam Units were expected to be placed in RMR status to support reliability in the Carlin Trend load pocket.

In the 2024 IRP, NV Energy makes several changes to its expectations for the Valmy Steam Units. First, the Company assumes that the proposed Valmy CTs will allow the ongoing RMR requirement at the Valmy Steam Units to end after

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[20] *Id.*, Vol. 8 at 18.

[21] *Id.*, Vol. 8 at 248.

[22] Docket No. 23-08015 Final Order, 96 ¶ 207, 99 ¶ 215.

2028.[23] As a result, the IRP model generally operates the Valmy Steam Units on a seasonal basis.[24]

Second, the Company is now less certain about the type of NO_X emissions control technology it will install at the Valmy Steam Units and whether SCR is needed or lower-cost technology could be utilized. The Company states that given regulatory uncertainty associated with the Regional Haze Rule and Good Neighbor Plan, there may be "flexibility" in the Company's emissions control technology decision at the Valmy Steam Units.[25]

Finally, NV Energy has revised its cost estimates for gas conversion and SCR installation at Valmy Units 1 and 2. The Company's cost **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** compared to the cost estimates for gas conversion and SCR that the Company provided in 2023.[26]

19. Q Please summarize your concerns about the Company's planning regarding the Valmy Steam Units.

A The Company's plans for Valmy Units 1 and 2 present several risks to customers. First, there is the risk that the Company will not pursue the operational changes it has modeled in the IRP – i.e., the end of must-run status at the Valmy Steam Units –, and therefore will not achieve the benefits of the preferred portfolio. The

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[23] NV Energy Response to Sierra Club ("SC") Data Request ("DR") 2-03 and SC DR 4-12 (The Company's public responses to Sierra Club data requests referenced in this testimony are provided in Attach. RA-2).

[24] NV Energy Response to SC DR 2-02 (Attach. RA-2).

[25] 2024 IRP Application, Vol. 8 at 15.

[26] *Id.*, Vol. 8 at 15 (Confidential Table GEN-4).

Company has not actively studied whether, and under what conditions, it can achieve the benefits of ceasing the ongoing must-run requirement. The Company has not yet begun to work with co-owner Idaho Power to explore the possibility of seasonal operations at the Valmy Steam Units after their conversion to gas.

Second, the installation of SCR was approved by the Commission in the Fifth Amendment to NV Energy's 2021 IRP based on the assumption that ongoing RMR status was required at one or both Valmy Steam Units. However, in the 2024 IRP, the installation of the proposed Valmy CTs in 2028 is expected to allow an end to the RMR requirement at the Valmy Steam Units. As I will explain, the end of RMR status at the Valmy Steam Units may reduce the capacity factors of those units enough that SCR is no longer a cost-effective emissions control option.

Additionally, the cost estimates of SCR and gas conversion have changed since the Fifth Amendment to the 2021 IRP,[27] but the Company has not re-studied its decisions to convert the Valmy Steam Units to gas and install SCR at those units. There is a risk that those projects are no longer cost-effective.

Finally, the Company should re-evaluate its planned 2049 retirement date for the converted Valmy Steam Units. Circumstances have changed since the Commission approved a 2049 retirement date for Valmy Units 1 and 2 in the 5th amendment to the 2021 IRP. Among other changes, the proposed Valmy CTs would reduce the need to keep the Valmy Steam Units running over the long term. The Company should re-evaluate the potential to cost-effectively retire and replace Valmy Units 1 and 2 with clean resources such as solar and storage.

[27] *Id.*

I will discuss each of these concerns further and make recommendations in the sections that follow.

i. ***<u>Operational decisions at Valmy Units 1 and 2: RMR requirement and seasonal operation</u>***

a. RMR requirement at Valmy Units 1 and 2

20. Q What are the Company's stated expectations for RMR at the Valmy Steam Units going forward?

A In the 2024 IRP, the Company states repeatedly in the narrative and testimony that it can end the ongoing must-run requirements at the Valmy Steam Units after installation of the proposed Valmy CTs in 2028, units which the Company describes as having "fast-start" capabilities.[28]

The ending of must-run requirements at the Valmy Steam Units is one of the main arguments in support of the proposed Valmy CTs. In its study of IRP portfolios, the Company states that "only the case that adds CTs at Valmy has the benefit of eliminating the existing Valmy steamer must-run requirement."[29] Accordingly, in

[28] 2024 IRP Application, Vol. 8 at 175, 238, 288.

[29] *Id.*, Vol. 8 at 238.

the IRP model, the Valmy Steam Units are not operated as must-run units after 2028.[30]

The Company states that once the proposed Valmy CTs are operational, must-run operation will no longer be required at Valmy Units 1 and 2 under most system conditions.[31] The Company asserts that must-run operation may still be required under certain circumstances, including during outages at the proposed Valmy CTs or transmission outages.[32] In discovery, NV Energy has stated that it will not be necessary to further study reliability in order to cease the must-run requirement at the Valmy Steam Units.[33]

21. Q Please discuss the economics of the must-run requirement at the Valmy Steam Units.

A Continuing the ongoing must-run requirement at the Valmy Steam Units after the Valmy CTs are installed in 2028 would result in excess costs for customers **[BEGIN CONFIDENTIAL]** [redacted]

[30] NV Energy Response to SC DR 4-20 (Confidential Attachment "24-05041 - SC 4-20-Conf Attach 01.xlsx") (The Company's confidential responses to Sierra Club data requests referenced in this testimony are provided in Attach. RA-3).

[31] 2024 IRP Application, Vol. 8 at 18; NV Energy Response to SC DR 2-03 (Attach. RA-2).

[32] NV Energy Response to SC DR 2-03 (Attach. RA-2).

[33] NV Energy Response to SC DR 3-03 (Attach. RA-2).

[redacted] **[END CONFIDENTIAL]**.[34] In contrast, while operating on must-run status, the converted Valmy Steam Units would be expected to have variable operating and fuel costs that total about **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].** [35]

22. Q What steps has the Company taken to confirm that it will be able to realize the benefits of ending the ongoing must-run requirement at the Valmy Steam Units?

A In discovery, NV Energy stated that "[t]he Companies have not performed a study of the specific conditions under which must-run operations at the Valmy steam units would or would not be required after the proposed Valmy CTs are in service."[36] It is concerning that NV Energy has been unable to produce any study or report confirming its plan to end the ongoing must-run requirement at the Valmy Steam Units.

When asked in discovery to provide studies showing that the proposed Valmy CTs will allow must-run to end at Valmy Units 1 and 2 under most system

[34] NV Energy Confidential Workpaper, "2024 IRP – F&PP Figures," Tab PF-4 (Attach. RA-7).

[35] NV Energy Response to SC DRs 4-16 (Confidential Attachment "24-05041 - SC 4-16-Conf Attach 01"), 4-22 (Confidential Attachment "24-05041 - SC 4-22-Conf Attach 01") (Attach. RA-3).

[36] NV Energy Response to SC DR 4-12(a) (Attach. RA-2).

conditions, the Company did not provide any analysis. Instead, the Company pointed generally to studies from the Fifth Amendment to the 2021 IRP.[37] In my review of those studies cited by the Company I did not find any specific evidence showing the Company's ability to end the must-run requirement at the Valmy Steam Units after the installation of the proposed Valmy CTs.

23. Q Why is it important for the Company to provide additional studies or reports showing that it can end must-run at the Valmy Steam Units once the Valmy CTs are in place?

A The Company is proposing to spend approximately $573.3 million on two gas CTs at the Valmy site. As shown in the 2024 IRP, the proposed Valmy CTs would reduce the Company's 20-year revenue requirement ("PWRR") by only about $18 million, indicating that the Valmy CTs would not create large net benefits for NV Energy's system.[38] The Company has claimed repeatedly that it will be able to end the ongoing must-run requirement at the Valmy Steam Units if it installs the proposed Valmy CTs, but has not offered any supporting studies or evidence.

Ending the ongoing must-run requirement at the Valmy Steam Units will be essential to realizing the expected benefits from the proposed Valmy CTs, including reduced greenhouse gas emissions from NV Energy's system. If the Company is not able to end the expensive must-run requirement at the Valmy

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[37] NV Energy Response to SC DR 4-12(b) (Attach. RA-2).

[38] 2024 IRP Application, Vol. 8 at 231.

Steam Units, the proposed Valmy CTs are likely to cause net system costs instead of net system benefits.

Of concern, the Company's internal decision report stated that there must be two generators running at all times in the Carlin Trend load pocket.[39] NV Energy should explain how the proposed Valmy CTs will replace must-run generation from the Valmy Steam Units, even if the Valmy CTs are not always online. Will the ability of the Valmy CTs to reach 200 MW of generation in approximately 10 minutes[40] be fast enough so that the Company does not risk losing load?

b. Seasonal Operation at the Valmy Steam Units

24. Q What does the Company's IRP modeling show about seasonal operation at the Valmy Steam Units?

A The Company acknowledges that its own IRP modeling finds that a shift to seasonal operations would be the lowest-cost option for customers: "the optimized economic dispatch in the production cost model inherently operates the repowered Valmy units seasonally in the Preferred Plan."[41] After the proposed Valmy CT units are installed in 2028, the IRP model chooses to allow **[BEGIN CONFIDENTIAL]** [redacted]

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[39] 5th Amendment to the 2021 IRP, Vol. 4, TRAN-5 at 1 (Attach. RA-5).

[40] 2024 IRP Application, Vol. 8 at 17.

[41] NV Energy Response to SC DR 2-02 (Attach. RA-2).

[redacted]

[END CONFIDENTIAL].

25. Q Should the Company begin planning for seasonal operation at Valmy Units 1 and 2 now?

A Yes. Seasonal operation of the Valmy Steam Units may help reduce costs even more than presented in the Company's preferred portfolio, since it may allow for

[42] NV Energy Response to SC DR 4-20 (Confidential Attachment "24-05041 - SC 4-20-Conf Attach 01") (Attach. RA-3).

[43] *Id.*

a reduction in capital costs that were not included in the IRP modeling.[44] The Company places two of its other gas-fired plants, Tracy Unit 3 and Clark Units 5–10, in reserve shutdown during the off-season.[45] The fact that the Company has chosen to place other gas units on its system into seasonal reserve shutdown indicates that it may be prudent to operate the converted Valmy Steam Units seasonally as well. The Company should look into the possibility of reducing costs for customers by operating the Valmy steam units seasonally.

26. Q What has the Company done to evaluate and/or prepare for seasonal operation at Valmy Units 1 and 2?

A Although the IRP model operates the Valmy Steam Units seasonally, the Company did not perform any further analysis or begin any preparation for seasonal operation of the Valmy steam units.[46]

The Valmy Steam Units would be placed into extended reserve shutdown by draining the boiler and placing them in a "hot air layup" to prevent corrosion. These steps can create cost savings by reducing wear and tear and preventing "pressure part failures."[47]

Despite this, the Company has not had discussions with Valmy co-owner Idaho Power about the potential to place the Valmy Steam Units into seasonal reserve

[44] *See* NV Energy Response to SC DR 5-06 (Attach. RA-2).

[45] NV Energy Response to SC DR 4-01 (Attach. RA-2).

[46] NV Energy Response to SC DRs 2-02, 4-10, 5-06 (Attach. RA-2).

[47] NV Energy Response to SC DR 4-09 (Attach. RA-2); NV Energy Response to SC DR 5-06 (Attach. RA-2).

shutdown.[48] This is concerning because without the collaboration of Idaho Power the Company will not be able to place the units in extended reserve shutdown. The Company states that it "has not taken any steps, nor does it intend to take any steps at this time to prepare for potential seasonal operations."[49]

The Company should have provided detailed analysis of the benefits, obstacles, and potential next steps toward placing the Valmy Steam Units into seasonal reserve shutdown. Given that the IRP model shows that the Valmy Steam Units are expected to be needed only on a seasonal basis, the Company should work to realize the savings that can be achieved by placing the units into an extended shutdown during those months.

ii. ***NV Energy's NO_X reduction technology decision***

27. Q How have the Company's plans for emissions control technologies at the Valmy Steam Units changed since the Fifth Amendment to the 2021 IRP?

A While the Company has not definitively stated that it will change its plans to install SCR at the Valmy Steam Units, in the 2024 IRP application the Company explains that it is currently evaluating its options for NO_X emissions reduction, including SCR and other technologies.[50]

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[48] NV Energy Response to SC DR 4-06 (Attach. RA-2).

[49] NV Energy Response to SC DR 4-03 (Attach. RA-2).

[50] 2024 IRP Application, Vol. 8 at 15.

28. Q Why are NV Energy's plans for SCR at the Valmy Steam Units being re-evaluated in this IRP?

A Future NO_X reduction requirements at the Valmy Steam Units are uncertain because of regulatory uncertainty in the Regional Haze Rule and Good Neighbor Plan. The Company has recently re-submitted its Regional Haze analysis and is awaiting a decision from NDEP and EPA.[51]

Additionally, the U.S. Circuit Court of Appeals for the Ninth Circuit has granted a temporary stay of the Good Neighbor Plan's requirements in Nevada. NV Energy asserts that it is unclear when the Good Neighbor Plan may eventually be implemented in Nevada.[52]

The Company asserts that in its recently updated Regional Haze "four-factor analysis," selective non-catalytic reduction ("SNCR") was shown to be a cost-effective emissions control technology for continued operations of the Valmy Steam Units until 2049.[53] NV Energy expects that if NDEP and EPA agree that SNCR can be used as the standard for Regional Haze compliance, then other technologies including or flue gas recirculation ("FGR") or SCR could also be used for compliance, depending on the outcome of litigation around the Good Neighbor Plan.[54]

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[51] *Id.*; *see also id.*, Vol. 3, Direct Testimony of Mathew Johns at 4.

[52] *Id.*, Vol. 8 at 24; *see also id.*, Vol. 3, Direct Testimony of Mathew Johns at 5.

[53] *Id.*, Vol. 8 at 15.

[54] *Id.*

Given this regulatory uncertainty, NV Energy indicates that in the 2024 IRP there is "flexibility" in the Company's emissions control technology decision at the Valmy Units 1 and 2.[55] The Company appears to be planning to defer a decision about emissions control technology for the Valmy Steam Units until there is certainty on further emissions reduction requirements under the Good Neighbor Plan.[56]

29. Q How might NV Energy eventually be able to comply with the Good Neighbor Plan?

A If the Good Neighbor Plan were to be implemented as envisioned in the EPA's original Federal Implementation Plan ("FIP"), emissions reductions consistent with the installation of SCR would be required at Valmy Units 1 and 2.[57] However, even if the Good Neighbor Plan requires emissions reductions consistent with the installation of SCR, the Company may be able to comply using some combination of less-expensive technology and reduced generation at the Valmy Steam Units.

The emissions requirements of the Good Neighbor Plan are based on NO_X allowance allocations. Therefore, the need to reduce NO_X emissions can be met in part through reduced operation of the Valmy Steam Units, such as through removing the ongoing must-run requirement and implementing seasonal operations, instead of solely through investment in emissions control

[55] *Id.*

[56] *See id.,* Vol. 3, Direct Testimony of Mathew Johns at 7.

[57] 2024 IRP Application, Vol. 8 at 25.

technology.[58] A generator's emissions during the Good Neighbor Plan's "ozone season" from May through September must be consistent with the installation of NO_X reduction technology, compared to baseline emissions levels. But that level of emissions reduction may be achieved simply by running the units less. Given the Company's expectation in the 2024 IRP that it can end the ongoing must-run requirement at the Valmy Steam Units, the Company must re-evaluate its investment in NO_X emissions reduction technology. An expensive technology like SCR may not be necessary if the Valmy Steam Units can meet regulatory requirements in part or entirely through reduced generation.

iii. <u>Gas conversion and SCR installation cost update</u>

30. Q Please describe the change in cost of the Valmy gas conversion and SCR installation.

A In the 2024 IRP, the Company updated its cost estimate for SCR installation and gas conversion at the Valmy Steam Units. The cost estimates for SCR and gas conversion **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[59]

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[58] NV Energy's Response to SC DR 3-06, Docket No. 23-08015 (provided in Attach. RA-6).

[59] 2024 IRP Application, Vol. 8 at 15 (Confidential Table GEN-4).

31. Q Has the Company considered the effects of the change in costs on the economics of the Valmy Steam Units?

A In the 2024 IRP, the Company did not provide an updated analysis comparing the economics of its plans for the Valmy Steam Units to alternatives, in light of the change in project costs and other relevant factors.

32. Q What are the risks of moving forward without re-evaluating the Company's plans at the Valmy Steam Units?

A If the Company moves forward with its plans with no further analysis, it risks incurring **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[60] This is a substantial risk that should cause the Company to reconsider and re-evaluate its plans.

iv. ***<u>2049 retirement date for Valmy Units 1 and 2</u>***

33. Q What justification has NV Energy provided for extending the retirement date of the Valmy Steam Units to 2049, given the changes in the planning environment since the Fifth Amendment to the 2021 IRP?

A To my knowledge, NV Energy has conducted no updated analysis that provides adequate support for the planned 2049 retirement date for the Valmy Steam Units in the 2024 IRP. There has been no updated retirement analysis despite significant changes since the Fifth Amendment to the 2021 IRP. When asked in discovery for analysis supporting the 2049 retirement date for the Valmy Steam Units, the

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[60] *See* 2024 IRP Application, Vol. 8 at 15 (Confidential Table GEN-4).

Company did not provide any new analysis. Instead, the Company pointed generally to the 2023 Valmy LSAP and other sections of the Fifth Amendment to the 2021 IRP in Docket No. 23-08015.[61] As shown in my testimony in that earlier docket, the Company's 2023 LSAP only looked at four scenarios for Valmy Units 1 and 2, and it only considered two potential retirement dates: 2025 or 2049.[62]

Studying a range of retirement dates, ideally through an optimized endogenous retirement scenario, is a resource planning best practice. A thorough, updated retirement analysis of Valmy Units 1 and 2 should look at a range of different retirement dates, and it should allow a capacity expansion model to select the optimal retirement dates.

v. ***Valmy Steam Units: Recommendations***

34. Q Given your concerns noted in the sections above, what are your recommendations regarding the Valmy Steam Units?

A NV Energy should comprehensively re-evaluate and provide additional support for its plans regarding Valmy Units 1 and 2. This reevaluation should include (1) supporting evidence showing the Company's ability to end the ongoing must-run requirement at both Valmy Steam Units, (2) an evaluation of optimal NO_X reduction technologies at each Valmy unit, (3) an evaluation of the benefits of

[61] NV Energy Response to SC DR 4-05 (Attach. RA-2).

[62] Direct Testimony of Rose Anderson on behalf of Sierra Club, Docket No. 23-08015 at 16 (Attach. RA-4); 5th Amendment to the 2021 IRP, Vol. 3, GEN-3 (LSAP) at 19-20 (Attach. RA-5).

switching the Valmy Steam Units to seasonal operations, and (4) a study of optimal retirement dates for the Valmy Steam Units.

My specific recommendations are as follows:

- NV Energy should provide a detailed technical explanation confirming that the proposed Valmy CTs will enable the Company to cease the ongoing must-run requirement at both Valmy Steam Units and enable the Company to realize the reductions in cost and pollution at those units as shown in the 2024 IRP preferred portfolio.

- Before the Commission grants approval of cost recovery for the proposed Valmy CTs in a rate case, NV Energy should be required to provide a detailed technical explanation and analysis confirming that it will be able to realize the expected cost and pollution reduction benefits at the Valmy Steam Units by removing the must-run requirement during normal system conditions (when no local generation or transmission is experiencing an outage).

- NV Energy should provide a detailed narrative explanation and analysis of the benefits, obstacles, and potential next steps toward implementing seasonal operations at Valmy Units 1 and 2 as part of its next IRP amendment or before both units are converted to gas in 2026, whichever is sooner.

- Because costs and circumstances have changed since the approval of NV Energy's plan to retire the Valmy Steam Units in 2049, the Company should continue to consider the possibility of retiring the Steam Units earlier than 2049, especially if it installs the proposed Valmy CTs. An updated retirement analysis that considers a variety of potential retirement dates for Valmy Units 1 and 2 should be provided in the Company's next IRP update.

V. LARGE CUSTOMER LOAD FORECAST AND THE NEED FOR THE PROPOSED VALMY CTS

35. Q Is there any circumstance where the proposed Valmy CTs would not be required to end must-run at the Valmy Steam Units?

A Yes. If NV Energy's forecast of load growth does not materialize, then there may be an option to end the must-run requirement at the Valmy Steam Units without installing the proposed Valmy CTs.

Before the recent increase in the major project load forecast in the 2024 IRP, the 2023 Valmy Must Run Study indicated that NV Energy's system would be reliable without must-run at Valmy Units 1 and 2 after the installation of GreenLink West, and even more reliable after the installation of GreenLink North (without any new CTs).[63] Further, the study found that the retirement of Valmy Units 1 and 2 would be possible after the installation of the GreenLink West transmission project: "With adequate generation support and additional transmission to offset significant load growth, the transmission system can withstand the retirement of Valmy."[64]

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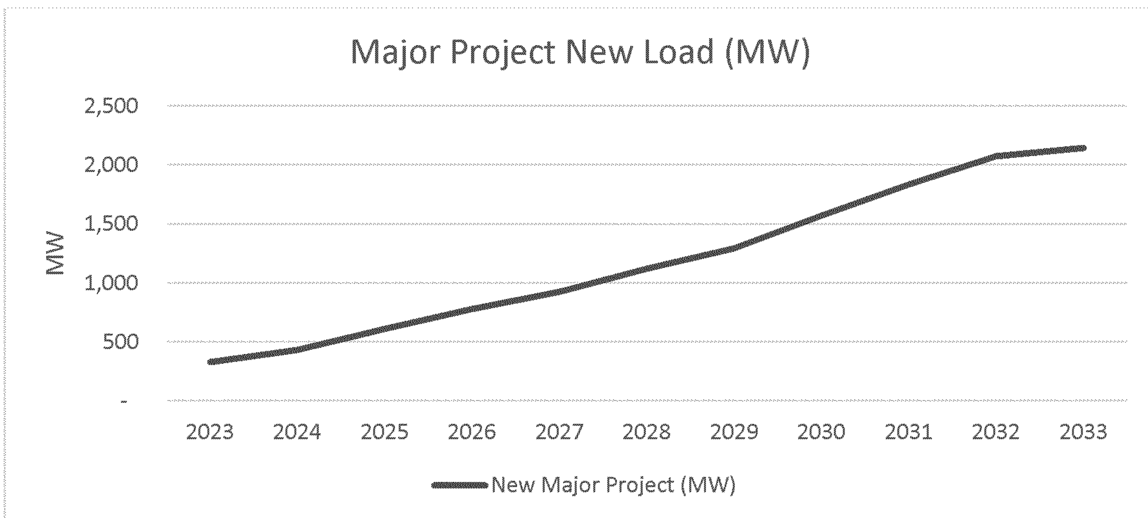
[63] 5th Amendment to the 2021 IRP, Vol. 4, TRAN-1 at 14, 108 (Attach. RA-5).

[64] *Id.*, Vol. 4, TRAN-1 at 17.

36. Q Please describe the Company's near-term large customer load forecast in the IRP.

A Large customer load is a substantial factor in the Company's load growth projections.[65] In NV Energy's 2024 IRP load forecast, "major projects" such as data centers represent about 611 MW of new load by 2025 and 1,575 MW of new load by 2030.[66] About 75 percent of the major project load growth in the IRP is attributed to data centers.[67]

Figure 2. NV Energy major project new load forecast (MW)



Source: 2024 IRP Application, Vol. 6, App. LF-1 at 83.

[65] *See* 2024 IRP Application, Vol. 2, Direct Testimony of Timothy Pollard at 18.

[66] *Id.*, Vol. 6, App. LF-1 at 66.

[67] *Id.*, Vol. 6, App. LF-1 at 32.

37. Q Please provide context for NV Energy's large customer industrial load forecast in this IRP.

A NV Energy is not unique in its load growth position: many utilities are similarly facing unprecedented projections of future load growth in their service territories. Data center load driven by the rise of artificial intelligence, coupled with increasing manufacturing load, have become drivers of large increases in projected future resource needs in jurisdictions across the country, including in Arizona, Virginia, Georgia, and Texas,[68] and now in Nevada. Some utilities have started taking steps to manage uncertainty about the level of the potential new load. For example, some utilities are weighting prospective load depending on how far that load has advanced in the development process, or are only including in their resource plans customers that have begun construction.

38. Q What is the Company's level of certainty about its near-term large customer load forecast?

A The Company's major projects load forecast is highly uncertain. The Company developed the forecast by taking existing large customer requests and discounting them based on whether they are in the study phase or have a signed agreement, with study phase projects discounted more than signed agreements.[69] The Company does not describe in detail its methodology but instead explains that it

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[68] John D. Wilson and Zach Zimmerman, *The Era of Flat Power Demand is Over*, GridStrategies (Dec. 2023), *available at* https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf.

[69] *See* 2024 IRP Application, Vol. 2, Direct Testimony of Timothy Pollard at 19; *id.*, Vol. 6 at 10.

discounts large customers' requests based on the Company's expectations about the probability of the load materializing.[70]

This methodology relies on the Company's subjective judgement about how likely new customers are to eventually accept service at the levels requested. The Company discounts the load requests from customers in the study phase by 85.4 percent and from those with signed agreements by 48.5 percent, on average.[71] In 2026, about 200 MW of the forecast new load from major projects is based on customers that were in the study phase at the time of the load forecast, without a signed agreement.[72]

39. Q How is the level of risk in the 2024 IRP different from load forecasts in past IRPs?

A The Company's "major project" new load forecast represents a 9 percent increase in NV Energy's peak load by 2026.[73] This large forecasted increase places customers at risk of paying for overbuild if the Company builds new infrastructure to support projected load growth and then that load does not materialize or is less than expected. In comparison, the increase in the Company's entire load forecast in the Fifth Amendment to the 2021 IRP was only 3.4% percent in the first two years of the load forecast.[74]

[70] *Id.*, Vol. 6, App. LF-1 at 30-31.

[71] *Id.*, Vol. 6, App. LF-1 at 31.

[72] *Id.*, Vol. 6, App. LF-1 at 30-31.

[73] NV Energy's forecast peak load in 2024 is 8,388 MW and major projects are forecast to add 782 MW of peak load by 2026; 2024 IRP Application, Vol. 6, App. LF-1 at 2, 66.

[74] Fifth Amendment to the 2021 IRP, Vol. 1, Ex. A – Narrative at 18.

40. Q What are the risks of planning for sudden increases in industrial load?

A The major risk of planning for sudden industrial load increases is that the Company could install new generation, transmission, and distribution assets to serve substantial new industrial load requests in the IRP, and then the new load growth could fail to materialize or could be significantly lower than projected. And because the industrial load contracts are so large, just a few inaccuracies in the forecast can create large variances. In this scenario, existing customers might be forced to pay for overbuilt projects that did not turn out to be necessary, or NV Energy could be required to absorb the costs of some investments if the Commission disallows cost recovery.

41. Q What steps does NV Energy take to reduce risks to all customers through its agreements with industrial customers?

A NV Energy has explained in discovery that it has "abnormal risk" agreements and provisions that apply to some large customers when they request a load increase.[75] NV Energy's abnormal risk agreements reduce the risks associated with investment in local transmission and distribution facilities immediately required to support a customer's request. However, the abnormal risk agreements do not reduce risk associated with the large amount of new generation and transmission investments required to serve the expected large customer load growth in long-term planning.

NV Energy's abnormal risk agreements reduce risks specific to individual contracts. They reduce risk by, among other measures, requiring a security for the amount of the utility's investment needed to implement the load request,

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[75] NV Energy Response to SC DRs 2-04, 4-15 (Attach. RA-2).

implementing a phased approach to transmission buildout, and implementing "reduction of service" charges if the applicant's load turns out to be lower than expected.[76]

However, the larger bulk electric system risks do not appear to be mitigated by the Company's abnormal risk agreements. The Company is planning on almost 1000 MW of new peak load from large industrial customers by 2027 and over 1500 MW by 2030.[77] This will require the Company to rapidly acquire new generation resources at a cost to customers, as shown by the installation of over 10,000 MW of new installed capacity by 2035 in the Company's preferred plan.[78]

42. Q What alternative cases or sensitivities does the Company include in the IRP to study the risk of over-building if its load forecast is too high?

A The Company developed a low load forecast in the 2024 IRP. The low load forecast includes "[r]emoval of all loads from those major projects currently in the Study Phase."[79] This lower industrial load forecast removes some of the uncertain industrial load, yet the largest portion of the large industrial load forecast is associated with signed agreements, and this portion of the load forecast is still included in the low load forecast.[80]

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[76] NV Energy Response to Sierra Club DR 2-04 (Attach. RA-2).

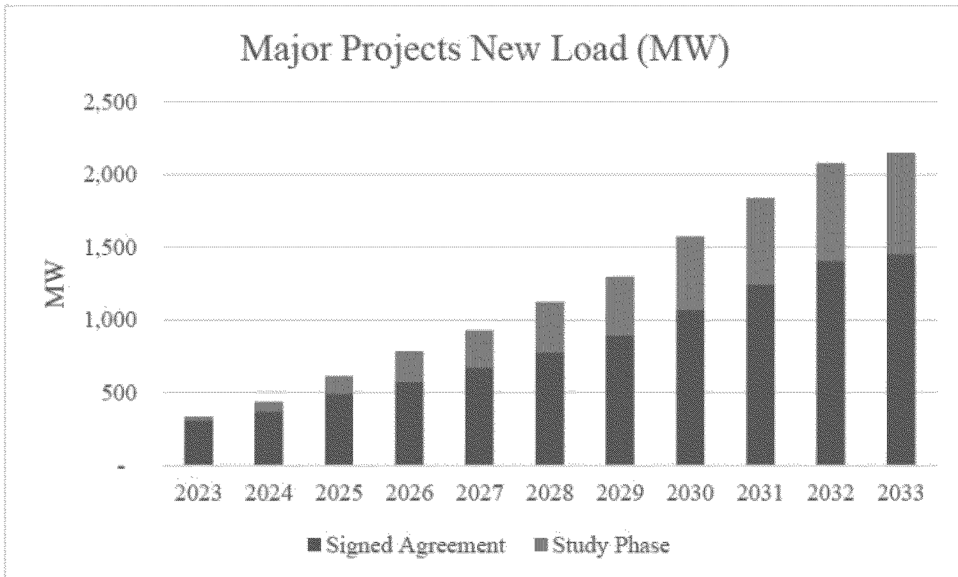
[77] 2024 IRP Application, Vol. 6, App. LF-1 at 66.

[78] *Id.*, Vol. 8 at 254.

[79] *Id.*, Vol. 6, App. LF-1 at 70.

[80] *Id.*, Vol. 6, App. LF-1 at 71.

Figure 3. NV Energy major projects new load (MW)



Source: 2024 IRP, Vol. 6, App. LF-1 at 83.

The low load forecast is only about 400 MW lower than the base load forecast in 2030, indicating that at least 1,100 MW of the 1,500 MW of new major project load is also included in the low load forecast.[81]

43. Q What alternative cases or sensitivities should the Company have included in the IRP?

A The Company should perform a thorough study of large customer load uncertainty in the IRP. This should include a low load forecast where the majority of major project industrial load does not materialize.

In addition to studying its chosen portfolios under a low load forecast, the Company should have developed at least one portfolio of resources based on a low load forecast without substantial new industrial load growth. This would

[81] *Id.*, Vol. 6., App. LF-1 at 71.

make the IRP a more useful planning tool by informing what NV Energy should do if the highly uncertain large customer load growth does not materialize or is lower than projected.

Finally, the Company should study the resources that would serve the Carlin Trend load pocket at the lowest cost in a variety of low load forecast scenarios.

44. Q What do you recommend with respect to the Company's load forecasts and their effects on the Company's plans for Valmy?

A The Company should notify the Commission immediately if any near-term large customer new load requests in Northern Nevada are cancelled or reduced. If the reduction in the load forecast is significant, it may justify further study of the Company's plans at the Valmy site, including the proposed Valmy CTs and investments in the Valmy Steam Units.

The Commission should direct NV Energy to provide alternate portfolios showing optimal resource plans if uncertain industrial load does not materialize. This should include the assessment of whether, under a lower industrial load forecast, the Company could both avoid the proposed Valmy CTs and end the must-run requirement at the Valmy Steam Units once the Greenlink West and Greenlink North transmission projects are in service.

45. Q Does this conclude your testimony?

A Yes.

AFFIRMATION

STATE OF NEVADA)
: ss.
CARSON CITY)

Pursuant to the requirements of NRS 53.045(1) and NAC 703.710, I, Rose Anderson, swear that I am the person identified in the attached Direct Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

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

Executed on: October 18, 2024 */s/ Rose Anderson*

ATTACHMENT RA-1

Rose Anderson Resume

Rose Anderson, Principal Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 617-812-1573
randerson@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Principal Associate*, September 2023 – Present.

- Provide research and analysis on integrated resource planning.
- Assess the economics of energy resources compared to alternatives and market purchases.
- Write expert testimony on power plant economics and integrated resource planning.

Oregon Public Utility Commission, Salem, OR. *Senior Economist,* October 2019 – September 2023; *Senior Renewables Analyst,* May 2018 – October 2019, *Utility Analyst,* September 2016 – May 2018.

Senior Economist:

- Prepared written comments and testimony.
- Lead OPUC staff review of utility Integrated Resource Plans (IRP) and resource acquisition proceedings.
- Evaluated utility production cost and capacity expansion modeling.
- Mentored OPUC staff regarding resource economics and best practices for review of utility filings.

Senior Renewables Analyst:

- Prepared written comments and testimony.
- Lead staff review and critical analysis of utility IRPs.
- Analyzed IRP modeling assumptions.
- Developed Excel model of rate impacts.

Utility Analyst:

- Reviewed and analyzed utility rate filings and workpapers for compliance.
- Prepared testimony in rate case and power cost filings.
- Reviewed utility production cost modeling inputs/outputs/workpapers.
- Lead and participated in review of power cost filings.

McCullough Research, Portland, OR. *Research Associate*, June 2013 – January 2015.

- Acquired, cleaned, and analyzed energy data sets in MS SQL and Excel.
- Researched nuclear energy and presented findings in a report.
- Analyzed bidding data from the MISO market.

EDUCATION

University of California, Davis. Davis, California
Master of Science in Agricultural and Resource Economics, 2016

University of Puget Sound, Tacoma, Washington
Bachelor of Arts in International Political Economy, 2007

PUBLICATIONS AND PRESENTATIONS

Florida Public Service Commission (Docket No. 20240025-EI): Direct Testimony of Rose Anderson on behalf of Sierra Club. June 11, 2024.

Public Utilities Commission of Nevada (Docket No. 23-08015): Direct Testimony of Rose Anderson on behalf of Sierra Club. December 19, 2023.

Oregon Public Utility Commission (Docket No. LC 79): Final Comments regarding NW Natural's 2021 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. March 30, 2023.

Oregon Public Utility Commission (Docket No. LC 79): Opening Comments regarding NW Natural's 2021 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. December 30, 2022.

Oregon Public Utility Commission (Docket No. LC 77): Final Comments and Staff Report regarding PacifiCorp's 2021 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. February 11, 2022.

Oregon Public Utility Commission (Docket No. LC 77): Opening Comments regarding PacifiCorp's 2021 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. December 3, 2021.

Oregon Public Utility Commission (Docket No. UM 2059): Staff Report regarding PacifiCorp's Application for Approval of its 2020 Request for Proposal. On behalf of Oregon Public Utility Commission Staff. October 6, 2021.

Oregon Public Utility Commission (Docket No. UM 2059): Comments regarding PacifiCorp's Application for Approval of its 2020 Request for Proposal. On behalf of Oregon Public Utility Commission Staff. August 19, 2021.

Oregon Public Utility Commission (Docket No. LC 70): Comments regarding PacifiCorp's Application for Approval of its 2019 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. August 18, 2021.

Oregon Public Utility Commission (Docket No. LC 71): Staff Report regarding The Third Update to NW Natural's 2018 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. July 12, 2021.

Oregon Public Utility Commission (Docket No. LC 71): Opening Comments regarding The Third Update to NW Natural's 2018 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. May 14, 2021.

Oregon Public Utility Commission (Docket No. UM 2059): Comments regarding PacifiCorp's Application for Approval of its 2020 Request for Proposal. On behalf of Oregon Public Utility Commission Staff. December 8, 2020.

Oregon Public Utility Commission (Docket No. UM 2059): Comments regarding PacifiCorp's Application for Approval of its 2020 Request for Proposal. On behalf of Oregon Public Utility Commission Staff. December 4, 2020.

Oregon Public Utility Commission (Docket No. UM 2005): Presentation of Rose Anderson on Integrated Resource Planning. On behalf of Oregon Public Utility Commission Staff. June 11, 2020.

Oregon Public Utility Commission (Docket No. LC 70): Comments regarding PacifiCorp's Application for Approval of its 2019 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. April 29, 2021.

Oregon Public Utility Commission (Docket No. LC 70): Report regarding PacifiCorp's Application for Approval of its 2019 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. April 17, 2020.

Oregon Public Utility Commission (Docket No. UM 2059): Report regarding PacifiCorp's Application for Approval of its 2020 Request for Proposal. On behalf of Oregon Public Utility Commission Staff. April 1, 2020.

Oregon Public Utility Commission (Docket No. LC 70): Comments regarding PacifiCorp's Application for Approval of its 2019 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. March 6, 2020.

Oregon Public Utility Commission (Docket No. LC 70): Comments regarding PacifiCorp's Application for Approval of its 2019 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. March 4, 2020.

Oregon Public Utility Commission (Docket No. LC 70): Comments regarding PacifiCorp's Application for Approval of its 2019 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. January 10, 2020

Oregon Public Utility Commission (Docket No. LC 70): Comments regarding PacifiCorp's Application for Approval of its 2019 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. October 25, 2019.

Oregon Public Utility Commission (Docket No. LC 71): Final Comments regarding NW Natural's 2018 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. December 31, 2018.

Oregon Public Utility Commission (Docket No. LC 70): Staff Report for the December 28, 2018 Special Public Meeting. On behalf of Oregon Public Utility Commission Staff. December 13, 2018.

Oregon Public Utility Commission (Docket No. LC 71): Opening Comments regarding NW Natural's 2018 Integrated Resource Plan. On behalf of Oregon Public Utility Commission Staff. October 15, 2018.

Oregon Public Utility Commission (Docket No. UE 230): Report of Rose Anderson on PGE's schedule 145 update request. On behalf of Oregon Public Utility Commission Staff. December 14, 2017.

Oregon Public Utility Commission (Docket No. UE 315): Report of Rose Anderson regarding PacifiCorp's request for revised rates. On behalf of Oregon Public Utility Commission Staff. December 9, 2016.

McCullough, R., Oursland, G., Anderson, R. *Nuclear Winter*. Electricity Policy. December 2014.

McCullough, R., Vatter, M., Anderson, R., Heimensen, J., Long, S., May, C., Nisbet, A., Oursland, G. *Economic Analysis of the Columbia Generating Station*. December 2013.

TESTIMONY

Oregon Public Utility Commission (Docket No. UE 420): Opening Testimony of Rose Anderson regarding PacifiCorp's 2024 Transition Adjustment Mechanism. On behalf of Oregon Public Utility Commission Staff. June 23, 2023.

Oregon Public Utility Commission (Docket No. UE 399): Rebuttal Testimony of Rose Anderson regarding PacifiCorp's Request for a General Rate Revision. On behalf of Oregon Public Utility Commission Staff. August 11, 2022.

Oregon Public Utility Commission (Docket No. UE 399): Opening Testimony of Rose Anderson regarding PacifiCorp's Request for a General Rate Revision. On behalf of Oregon Public Utility Commission Staff. June 22, 2022.

Oregon Public Utility Commission (Docket No. UE 390): Rebuttal Testimony of Rose Anderson regarding PacifiCorp's 2022 Transition Adjustment Mechanism. On behalf of Oregon Public Utility Commission Staff. July 30, 2021.

Oregon Public Utility Commission (Docket No. UE 390): Opening Testimony of Rose Anderson regarding PacifiCorp's 2022 Transition Adjustment Mechanism. On behalf of Oregon Public Utility Commission Staff. June 09, 2021.

Oregon Public Utility Commission (Docket No. UE 374): Rebuttal Testimony of Rose Anderson regarding PacifiCorp's Request for a General Rate Revision. On behalf of Oregon Public Utility Commission Staff. July 24, 2020.

Oregon Public Utility Commission (Docket No. UE 374): Opening Testimony of Rose Anderson regarding PacifiCorp's Request for a General Rate Revision. On behalf of Oregon Public Utility Commission Staff. June 4, 2020.

Oregon Public Utility Commission (Docket No. UE 339): Opening Testimony of Rose Anderson regarding PacifiCorp's 2019 Transition Adjustment Mechanism. On behalf of Oregon Public Utility Commission Staff. June 11, 2018.

Oregon Public Utility Commission (Docket No. UE 333): Opening Testimony of Rose Anderson regarding Idaho Power's 2018 Annual Power Cost Update. On behalf of Oregon Public Utility Commission Staff. February 12, 2018.

Oregon Public Utility Commission (Docket No. UG 325): Opening Testimony of Rose Anderson regarding Avista's Request for a General Rate Revision. On behalf of Oregon Public Utility Commission Staff. July 20, 2017.

Oregon Public Utility Commission (Docket No. UE 319): Opening Testimony of Rose Anderson regarding Portland General Electric's Request for a General Rate Revision. On behalf of Oregon Public Utility Commission Staff. June 16, 2017.

Resume updated September 2023

ATTACHMENT RA-2

NV Energy’s Public Responses to Sierra Club Data Requests in Docket No. 24-05041

NV Energy Response to SC DR 2-02

NV Energy Response to SC DR 2-03

NV Energy Response to SC DR 2-04

NV Energy Response to SC DR 3-01

NV Energy Response to SC DR 3-03

NV Energy Response to SC DR 4-01

NV Energy Response to SC DR 4-03

NV Energy Response to SC DR 4-04

NV Energy Response to SC DR 4-05

NV Energy Response to SC DR 4-06

NV Energy Response to SC DR 4-07

NV Energy Response to SC DR 4-09

NV Energy Response to SC DR 4-10

NV Energy Response to SC DR 4-12

NV Energy Response to SC DR 4-15

NV Energy Response to SC DR 5-05

NV Energy Response to SC DR 5-06

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	07-31-2024
REQUEST NO:	SC 2-02	**KEYWORD:**	seasonal operations valmy; reduce costs evaluation conversion new CTs
REQUESTER:	Woolsey	**RESPONDER:**	Heath, Brandon (NV Energy)

REQUEST:

Reference: Seasonal operations at Valmy

Question: Has NV Energy evaluated the potential to reduce costs through seasonal operation of the existing Valmy steam units after their conversion to gas and after the addition of the proposed new CTs at Valmy? If so, please provide all studies, workpapers, and findings associated with this evaluation.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

NV Energy did not evaluate nor impose seasonal operation limitations on the repowered Valmy steamer units after the new Valmy CTs are in service. However, the optimized economic dispatch in the production cost model inherently operates the repowered Valmy units seasonally in the Preferred Plan as can be seen in the PLEXOUT workpaper.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	07-31-2024
REQUEST NO:	SC 2-03	**KEYWORD:**	must-run operations valmy; conversion new CTs
REQUESTER:	Woolsey	**RESPONDER:**	Lescenski, John

REQUEST:

Reference: Must-run operations at Valmy

Question: Will the Company cease must-run operations at the existing Valmy steam units after they have been converted from coal to gas and after the proposed new Valmy CTs are in service? Are there any circumstances that would preclude the company from ending must-run designation at the existing Valmy units after the coal-to-gas conversion is complete and after the proposed new CTs are online? If so, please describe those circumstances.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

The Companies expect that the Valmy Simple Cycle Units will be able to allow the existing Valmy steam units cease must-run operations under most system conditions. System conditions such as outages on the peaking units or outages on the transmission system could result in must-run conditions for the existing steam units, but no specific circumstances have been identified at this time.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	07-31-2024
REQUEST NO:	SC 2-04	**KEYWORD:**	commercial industrial load growth; LF-3 LF-4 vol 6 p56-57
REQUESTER:	Woolsey	**RESPONDER:**	Pollard, Tim

REQUEST:

Reference: Commercial and industrial load growth

Question: Please refer to the Company's projections of substantial near-term load growth from large Commercial and Industrial (C&I) customers in Tables LF-3 and LF-4 on pages 56-57 of Volume 6 of the Application. Please discuss what steps NV Energy has taken to reduce risks to other customer classes, including residential customers, and what assurances the company has received from these C&I customers that expected near term load growth will materialize.

a. Does the Company have any signed agreements with the large C&I customers causing the majority of the near-term load growth? If so, please describe the agreements and their terms.

b. Has the Company received or requested any payments or financial commitments from the large C&I customers? Reference AEP Ohio's recent application for example: https://www.utilitydive.com/news/aep-ohio-data-center-crypto-rates-puc/716150/

c. What steps has NV Energy taken to reduce risks to customers associated with building new resources to serve large, uncertain C&I customer load growth in the near term?

RESPONSE CONFIDENTIAL (yes or no): No

ATTACHMENT CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: Five (Zipped)

RESPONSE:

The interconnection of all new load customers to the electric grid follows the current Rule 9 tariff. This tariff includes a line extension agreement, which defines specific terms of service and cost responsibilities for both the utility and the customer.

a) Yes. The types of agreements signed and their standard terms are described in attachment 24-05041 – SC 2-04-Attach 1 templates.

b) Yes. The financial responsibilities of connecting a customer to the electric grid for both the utility and customer are defined in the current Rule 9 tariff interconnection agreements.

c) The current tariff and agreements include protections to reduce risk for current ratepayers. The Company implements, in an ongoing effort, several strategies to mitigate risk through the following measures:
- applying abnormal risk provisions to the applicable agreements,
- requiring a security for up to 100% of the utility investment,
- requiring an advance subject to potential refund,
- implementing a phased approach to construct transmission infrastructure over time as the load materializes,
- establishing agreement milestones to ensure the Applicant and Company are progressing together,
- implementing reduction of service charge provisions in case an Applicant's load is short, and
- for those customers already in service, obtaining annual updated load forecasts to advise transmission planning studies so models reflect actual loads and revised customer stated load forecasts, so supplemental phases/projects are only triggered when required. In addition, the Company is now imposing an increase to the reduction of service charge provisions and expanding the advance subject to potential refund provisions for large transmission projects to further minimize risk to the current ratepayers.

Further, the retail load forecast mitigates the customer provided Rule 9 ramp-up schedule peak loads to account for historically experienced delays, likely reductions in service levels, and expected load factor considerations to forecast estimated loads that the utility is required to serve as part of the overall system. Please see Section 3.D in Technical Appendix LF-1 for more information on this process.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	08-23-2024
REQUEST NO:	SC 3-01	**KEYWORD:**	load forecast SC 2-04(c); industrial large customers
REQUESTER:	Woolsey	**RESPONDER:**	Pollard, Tim

REQUEST:

Reference: Load Forecasts

Question: See NV Energy's response to Sierra Club DR 2-04(c). Does NVE obtain annual load forecasts from all of its industrial customers or only certain large customers? If only some large customers provide load forecasts, please explain which ones.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

No, annual load forecasts are not requested from all industrial customers. Load absorption schedules are typically requested for new large projects to be served at higher voltages requiring a High Voltage Distribution agreement, or for customers who may require multiple feeders and new substation transformers for their large project. Further, Rule 9 section A.23.a.4 requires large customers to provide a load schedule with the Project's Estimated Full Build-Out Peak Load requirements.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	08-23-2024
REQUEST NO:	SC 3-03	**KEYWORD:**	must run operations valmy steam units CTs
REQUESTER:	Woolsey	**RESPONDER:**	Pottey, Charles (NV Energy)

REQUEST:

Reference: Must-Run Operations at Valmy

Question: Please explain the steps the Company will take to cease must-run operations of the Valmy steam units after conversion of the coal-fired units to gas and the installation of CTs at the Valmy site.

a. Will a new system reliability study be required?

b. Will any regulatory requirements need to be met in order to cease must-run at Valmy? If so please list and explain the requirements.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

After the addition of the two combustion turbines with fast-start capabilities, the existing Valmy units must-run procedures can be retired, under most operating conditions. It is the fast-start nature of the combustion turbines that allows the must-run requirement to be lifted.

a. A new system reliability study is not expected to be required.

b. No regulatory requirements are currently expected to be needed to cease must-run operations at Valmy.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	09-12-2024
REQUEST NO:	SC 4-01	**KEYWORD:**	SC 3-04(a); thermal generating units seasonal operation 2020-2024
REQUESTER:	Woolsey	**RESPONDER:**	Lescenski, John

REQUEST:

Reference: Valmy steam units – seasonal operations

Question: See NV Energy's response to SC DR 3-04(a). Please list all NV Energy thermal generating units that have been operated seasonally in each year from 2020 to 2024.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

During the years 2020 to 2024, Clark 5-10 and Tracy 3 have been put in reserve shutdown during the off season.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	09-12-2024
REQUEST NO:	SC 4-03	**KEYWORD:**	SC 2-02; valmy steam units seasonal operation after gas conversion
REQUESTER:	Woolsey	**RESPONDER:**	Lescenski, John

REQUEST:

Reference: Valmy steam units – seasonal operations

Question: Please refer to the Company's response to SC DR 2-02. Please provide a narrative description of:

a) any steps that NV Energy has taken, or plans to take, to assess whether it should implement seasonal operation at the Valmy steam units after conversion to gas, and

b) any steps that NV Energy has taken, or plans to take, to prepare for potential seasonal operation.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

NV Energy has not taken any steps, nor does it intend to take any steps at this time to prepare for potential seasonal operations. The Plant Operations and Maintenance teams are prepared to operate the units in support of the bulk energy system, however, they are called upon to operate.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	09-12-2024
REQUEST NO:	SC 4-04	**KEYWORD:**	SC 2-02; PLEXOUT repowered valmy steam units seasonal operation
REQUESTER:	Woolsey	**RESPONDER:**	Williams, Kimberly

REQUEST:

Reference: Valmy steam units – seasonal operations

Question: Please refer to the Company's statement in response to SC DR 2-02 that "[t]he optimized economic dispatch in the production cost model inherently operates the repowered Valmy units seasonally in the Preferred Plan as can be seen in the PLEXOUT workpaper." Did the Company's modeling quantify approximately how much the Company could save by operating the repowered Valmy steam units seasonally (as in the Preferred Plan) as opposed to a scenario where the repowered Valmy steam units are operated year-round?

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

The production cost model optimally dispatches the given portfolio with the given inputs in all cases and plans. The Companies did not purposefully create a suboptimal dispatch of the Preferred Plan in order to assess the relative benefits of the optimal dispatch of that plan.

However, the Alternate Plan, due to the lack of the Valmy CTs, requires the continuing must-run of the Valmy steamers and therefore a comparison between the Preferred and Alternate Plans would be a comparison between a plan in which the repowered Valmy steamers inherently operate seasonally and one in which they operate year-round.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	09-12-2024
REQUEST NO:	SC 4-05	**KEYWORD:**	valmy steam units retirement 2049 other dates
REQUESTER:	Woolsey	**RESPONDER:**	Lescenski, John

REQUEST:

Reference: Valmy steam units - retirement

Question: Please provide a description and workpapers, in electronic Excel format, for any analysis performed by the Company supporting:

a) a 2049 retirement date for the Valmy steam units,
b) any other retirement date for the Valmy steam units.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

This retirement date and LSAP for the 2049 retirement date was supported and approved by the Commission in Docket No. 23-08015. Please see that Docket for the requested information, specifically: Supply Side Narrative, F. New Generation Projects, A. Valmy Natural Gas Conversion and Technical Appendix GEN-3.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	09-12-2024
REQUEST NO:	SC 4-06	**KEYWORD:**	idaho power discussion valmy steam units seasonal shutdown gas conversion
REQUESTER:	Woolsey	**RESPONDER:**	Lescenski, John

REQUEST:

Reference: Valmy steam units – seasonal operations

Question: Has NV Energy discussed or communicated with Idaho Power about the potential for seasonal shutdown of Valmy units 1 & 2 after the units' conversion to gas? If so, please describe the discussions or communication(s) and their results.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

NV Energy regularly meets with its partner and discusses current plant operations and future operations projections. Idaho Power has been informed that the units are currently being operated under a must-run condition and that condition could change if NV Energy constructs new CTs at the Valmy site. Both Idaho Power Company and NV Energy can operate the units on an as needed basis as they have since the partnership began in 1979.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	09-12-2024
REQUEST NO:	SC 4-07	**KEYWORD:**	idaho power valmy seasonal operation economic analysis
REQUESTER:	Woolsey	**RESPONDER:**	Lescenski, John

REQUEST:

Reference: Valmy steam units – seasonal operations

Question: To the Company's knowledge, has Idaho Power performed any analysis of the economics of seasonal operation at Valmy? Has NV Energy requested Idaho Power perform such analysis?

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

NV Energy is not aware of any specific analysis that may have been completed by Idaho Power regarding the economics of seasonal operation of its share of the Valmy Units. Idaho Power regularly gets out of the units during the off-season periods and does not operate its share whether NV Energy is operating the units or not.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	09-12-2024
REQUEST NO:	SC 4-09	**KEYWORD:**	SC 3-04(b) valmy steam units seasonal operation, process draining shutdown
REQUESTER:	Woolsey	**RESPONDER:**	Lescenski, John

REQUEST:

Reference: Valmy steam units – seasonal operations

Question: See NV Energy's response to SC DR 3-04(b). Please provide further detail on the process of draining and shutting down the units for seasonal operation. Please include financial and engineering/mechanical reasons for draining the plant, as well as a description of the draining and shutting down process.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

In the winter, if a unit is expected to be shut off for more than a week, the unit will be drained to prevent freeze issues. In warmer times of the year, if a unit is expected to be shut off for more than 30 days under normal conditions where freezing is not an issue, it will be drained.

Per operating procedures, Valmy steam units are flashed dried during draining, by draining the boiler while the unit is still hot. The units are then placed in a hot air layup. Depending on ambient air temperature and humidity, a fan is used to blow dry air through the waterside of the boiler. Electric air heaters are used on the fireside to warm surfaces and dry out the waterside. The layup prevents corrosion in the boiler, preserving the integrity of the boiler and preventing costs associated with premature pressure part failures.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	09-12-2024
REQUEST NO:	SC 4-10	**KEYWORD:**	SC 3-04(c) valmy steam units seasonal operation fuel cost savings variables
REQUESTER:	Woolsey	**RESPONDER:**	Lescenski, John

REQUEST:

Reference: Valmy steam units – seasonal operations

Question: Please refer to the Company's responses to SC DR 3-04(c) and SC DR 2-02.

a) Would avoided fuel costs be the primary category of cost savings associated with seasonal operations of the Valmy steam units?

b) Would there be any other variable cost savings associated with seasonal operations?

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

Fuel costs would be the primary cost savings associated with seasonal operations. Other lesser cost savings may be realized as a result of lower operations, such as lower chemicals use.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	09-12-2024
REQUEST NO:	SC 4-12	**KEYWORD:**	SC 2-03; valmy must-run operations, conditions study analysis
REQUESTER:	Woolsey	**RESPONDER:**	Pottey, Charles (NV Energy)

REQUEST:

Reference: Valmy – must-run operations

Question: Please refer to the Company's response to SC DR 2-03.

a) Has the Company performed a study of the conditions under which must-run operations at the Valmy steam units would or would not be required after the proposed Valmy CTs are in service?

b) Please provide all studies, analyses, modeling, or data which supports NV Energy's statement that "[t]he Companies expect that the Valmy Simple Cycle Units will be able to allow the existing Valmy steam units cease must-run operations under most system conditions. System conditions such as outages on the peaking units or outages on the transmission system could result in mustrun conditions for the existing steam units, but no specific circumstances have been identified at this time."

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

a) The Valmy must-run requirement is based on the need for voltage support in the Carlin Trend area and the need to be able to rapidly ramp up generation to reduce system imports following certain contingencies. If the Valmy units are offline, it can take up to 24 hours or more to bring them online. Following a contingency, operations generally must rebalance the system within 15 minutes to prepare the system for the next contingency. The Companies have not performed a study of the specific conditions under which must-run operations at the Valmy steam units would or would not be required after the proposed Valmy CTs are in service. However, detail studies concerning the operational issues in the Valmy and Carlin Trend area have been prepared. Copies of these studies concerning the Valmy must-run requirement were provided in Commission Docket No. 23-08015, NPC/SPPC 5th IRP Amendment, Volume 4, Technical Appendixes TRAN-1 Valmy Must Run-2023 and TRAN-5 Valmy Must Run KDR.

b) Studies concerning the Valmy must-run requirement were provided in Commission Docket No. 23-08015, NPC/SPPC 5th IRP Amendment, Volume 4, Technical Appendixes TRAN-1 Valmy Must Run-2023 and TRAN-5 Valmy Must Run KDR. Based on these studies NV Energy anticipates that, under most conditions, the quick start CTs would be sufficient to remove the Valmy must-run requirement. However, even with the addition of these quick start CTs, there could be system conditions that still require the operation of the Valmy units depending on the amount of load growth, resource additions and contingencies experienced.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	09-12-2024
REQUEST NO:	SC 4-15	**KEYWORD:**	SC 3-02 large customer abnormal risk agreements
REQUESTER:	Woolsey	**RESPONDER:**	Potts, Kelly (NV Energy)

REQUEST:

Reference: Large customer abnormal risk agreements

Question: Please refer to the Company's response to SC DR 3-02. Of the customers responsible for the increase in the industrial load forecast in the first five years of the IRP planning timeframe:

a) How many of those customers are there?

b) What percentage of those customers have signed an abnormal risk agreement?

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

a) A combination of 43 signed agreement and study phase major projects were considered in the industrial load forecast.

b) All signed customer agreements have abnormal risk provisions. While some of the agreements may not specifically identify "Abnormal Risk", all of the agreements meet the "Large Project" threshold. Rule 9, A.23 – Service to Large Projects and Rule 9, A.24 – Abnormal Risk Projects have the same requirements and the necessary provisions have been included in 100 percent of the customer agreements.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	09-30-2024
REQUEST NO:	SC 5-05	**KEYWORD:**	SC 4-01 seasonal operations clark 5-10 tracy 3 reserve shutdown off season, econ
REQUESTER:	Woolsey	**RESPONDER:**	Lescenski, John

REQUEST:

Reference: Seasonal operations

Question: See the Company's response to SC DR 4-01. Please explain the Company's reasons for placing Clark Units 5-10 and Tracy Unit 3 in reserve shutdown during the off season. Please include:

a. a narrative explanation of any economic benefits from the seasonal reserve shutdown,
b. any policy, operational, or other considerations that contribute to the decision to operate the units seasonally.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

The decision to put the units in reserve shutdown is based on system needs. If a unit is not expected to operate for a period of time that exceeds a normal shutdown, the decision may be made to put it in a reserve shutdown mode. Depending on the duration of the expected shutdown, different actions are taken based on the type of unit and time of year, as discussed in the Companies' response to Sierra Club DR 4-09 in this Docket.

a. The primary economic benefit of seasonal reserve shutdown is reduction in fuel costs and wear and tear on the units when the unit is not operating

b. No specific policy, operational or other considerations contribute the decision to operate units seasonally, other than what was explained above. When the units are not expected to operate for a period of time, they can be put in a reserve shutdown.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	09-30-2024
REQUEST NO:	SC 5-06	**KEYWORD:**	SC 4-10(b) valmy seasonal shutdown, O&M cost savings, capital cost savings
REQUESTER:	Woolsey	**RESPONDER:**	Lescenski, John

REQUEST:

Reference: Seasonal operations

Question: See NV Energy's response to SC DR 4-10(b) discussing variable cost savings associated with seasonal operations. Please identify, with specificity, any potential fixed O&M cost savings or capital cost savings associated with seasonal shutdown of Valmy.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

Since Fixed O&M costs are by nature fixed, they do not change whether the unit is operating or in reserve. Some capital cost savings may be realized by reducing wear and tear on the equipment that is not running for a period of time, but the Companies have not developed any estimates for potential capital cost savings associated with seasonal shutdowns

ATTACHMENT RA-3

NV Energy's Confidential Responses to Sierra Club Data Requests in Docket No. 24-05041

NV Energy Response to SC DR 4-16 (Confidential Attachment "24-05041 - SC 4-16-Conf Attach 01")

NV Energy Response to SC DR 4-20 (Confidential Attachment "24-05041 - SC 4-20-Conf Attach 01")

NV Energy Response to SC DR 4-22 (Confidential Attachment "24-05041 - SC 4-22-Conf Attach 01")

These files are marked confidential and will be made available for those parties who have signed the protective agreement.

ATTACHMENT RA-4

Direct Testimony of Rose Anderson in Docket No. 23-08015
(excerpt without attachments)

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the fifth amendment to its 2021 Joint Integrated Resource Plan)	Docket No. 23-08015

DIRECT TESTIMONY OF ROSE ANDERSON

ON BEHALF OF SIERRA CLUB

DECEMBER 19, 2023

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RA-4:	North American Electric Reliability Corporation, PRC-010-1 – Undervoltage Load Shedding
RA-5:	Excerpt of Federal 'Good Neighbor Plan' for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 33,654, 33,654–36,666, 36,754–36,844 (June 5, 2023)
RA-6:	NV Energy Response to Staff Data Request 01

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q Please state your name and occupation.

A My name is Rose Anderson. I am a Principal Associate at Synapse Energy Economics. My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

2. Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

3. Q Please summarize your work experience and educational background.

A At Synapse, I review planning assumptions and modeling in utility integrated resource plans.

Before joining Synapse, I performed economic analysis at the Oregon Public Utility Commission and at McCullough Research, an energy economics consulting firm.

A copy of my current resume is attached as Attachment RA-1.

4. Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

5. Q Have you testified previously before the Nevada Public Utilities Commission?

A No.

6. Q What is the purpose of your testimony in this proceeding?

A I evaluate the proposals of Nevada Power Company and Sierra Pacific Power Company (together, "NV Energy" or "the Company") to make significant changes to its plans for Valmy Generating Station ("Valmy") Units 1 and 2 and Tracy Generating Station ("Tracy") Units 4 and 5 as part of the Company's application for approval of the Fifth Amendment to its 2021 Joint Integrated Resource Plan ("IRP"). Specifically, I analyze the Company's proposal to convert Valmy Units 1 and 2 from coal to gas, install selective catalytic reduction ("SCR") technology to control nitrogen oxide ("NO_X") emissions, and to make capital investments to operate the repowered units until 2049. I also review the Company's proposal to install SCR at Tracy Units 4 and 5 and make capital investments to extend the operations of those units until 2049. I evaluate the support provided for these proposals in the Company's application and discuss alternatives that the Company did not consider. I recommend further analysis before moving forward with the Company's plans.

7. Q How is your testimony structured?

A In Section 3, I discuss the Company's proposal for the Valmy plant. In Section 4, I discuss the Company's proposal for Tracy Units 4 and 5.

8. Q What documents do you rely upon for your analysis, findings, and observations?

A My analysis relies primarily upon the application for the Fifth Amendment to the 2021 IRP filed by the Company, as well as the Company's responses to discovery requests.

II. FINDINGS AND RECOMMENDATIONS

9. Q Please summarize your findings.

A My primary findings are:

1. The Company's application does not provide adequate support for its proposal to convert Valmy Units 1 and 2 to gas, install SCR, and run the units through 2049. In particular, the Company does not adequately analyze alternatives to the Valmy proposal that could meet identified needs in the Carlin Trend load pocket potentially at a lower cost, and with better adherence to the cost causation principle of ratemaking.

2. Based on the studies provided with this application, Valmy is needed for reliability in the Carlin Trend load pocket only before Greenlink West and Greenlink North are both in place, expected in 2028.[1] The Company is requesting to spend $82 million in ratepayer dollars on Valmy to provide support to Carlin Trend load pocket that likely is only needed for a few years.

3. It appears that the investment in Valmy to support Distribution Only Service ("DOS") customers in the Carlin Trend load pocket may not follow the cost-causation principle of ratemaking. The Company's Valmy proposal would incur costs in support of DOS customers that these customers would not pay for directly through their NV Energy tariff.[2] The Company's application did not address whether Valmy proposal costs would be included in DOS customers' Federal Energy Regulatory Commission ("FERC") Open Access Transmission Tariff ("OATT") with NV Energy.[3]

[1] Greenlink West is currently planned for service in May 2027 and Greenlink North is expected in December 2028. *See* NV Energy Response to Sierra Club Data Requests ("SC DR") 4-01, 4-02 (The Company's responses to Sierra Club data requests referenced in this testimony are provided in Attachment ["Attach."] RA-2).

[2] Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the Fifth Amendment to the 2021 Joint Integrated Resource Plan [hereinafter "Application"], Vol. 1 at 251.

[3] Sierra Club has sent a data request to NV Energy regarding the contribution of Carlin Trend DOS customers to the cost of the Company's Valmy proposal via the OATT. The Company's response to that request is pending.

4. The Company's economic analysis for Tracy Units 4 and 5 is inadequate to support the Company's proposal to install SCR at the plant and extend the plant's operating life until 2049. The marginal expected benefits of the project do not outweigh the risks. In addition, the Company does not need to make a decision regarding SCR and continued operation at Tracy Units 4 and 5 at this time, since must-run generation is not required at these units. The NO_X emissions reductions necessary for compliance with the U.S. Environmental Protection Agency's ("EPA)" new Good Neighbor Plan can be facilitated through reduced generation at Tracy 4 and 5.

10. Q Please summarize your recommendations.

A Based on my findings, I offer the following recommendations:

1. The Commission should find the portion of the Company's application that proposes conversion from coal to gas, SCR installation, and operation until 2049 at Valmy Units 1 and 2 to be inadequate. The Company has not provided enough support for this plan.

2. The Company should update its Valmy analysis to more comprehensively evaluate its options. These options should include reducing the operating timeframe, installing selective non-catalytic reduction ("SNCR") instead of SCR, and making investments in only one Valmy unit.

3. The Commission should find the portion of the Company's application that proposes SCR installation at Tracy Units 4 and 5 to be inadequate.

4. The Company should not proceed with SCR installation and capital expenses for continued operation of Tracy Units 4 and 5 at this time. There is not an urgent need to install SCR, since the Company should be able to manage the EPA's expected new NO_X emissions reduction requirements through reduced dispatch at Tracy Units 4 and 5. The economic analysis of SCR installation and operation of Tracy through 2049 showed a very small expected benefit, while the increased carbon emissions and associated risks of this approach would be substantial.

III. VALMY UNITS 1 AND 2

11. Q Please describe the current Valmy plant.

A Valmy is a 522 megawatt ("MW") power plant located west of Battle Mountain, Nevada, with two coal-fired steam units.[4] The plant is co-owned by NV Energy and Idaho Power. NV Energy owns a 50 percent share of the plant's generating capacity, i.e. 261 MW.[5] The units were built in 1981 and 1985 and are 42 and 38 years old, respectively.[6]

12. Q Prior to the current application, what was the Company's plan for retirement of Valmy?

A The Company's pre-application planned retirement date for Valmy Units 1 and 2 is in 2025.[7] The Title V air quality permit for Valmy Units 1 and 2 imposes a federally enforceable retirement date of December 31, 2028.[8]

13. Q Why has NV Energy filed this update and proposed modifications for Valmy Units 1 and 2?

A In Docket No. 16-07001, the Commission directed the Company to update its 2018 Valmy retirement study, called the Life Span Analysis Process ("LSAP").

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[4] Application, Vol. 1 at 63.
[5] *Id.* at 63, 64 n.24.
[6] *Id.* at 64 (Table GEN-1).
[7] *Id.*
[8] *Id.* at 67.

14. Q What is NV Energy requesting in this docket related to Valmy Units 1 and 2?

A NV Energy is requesting approval of its proposal to spend $20.4 million to convert Valmy Units 1 and 2 from coal to gas and spend $30 million to install SCR technology at both units. It is also asking to spend $32.25 million to extend the operating lives of those units until 2049.[9] Specifically, the Company proposes to convert Unit 1 from coal to gas by December 31, 2025, and to convert Unit 2 from coal to gas by June 1, 2026.[10] The total cost of the project, shared between Idaho Power and NV Energy, would be $165 million. NV Energy's 50 percent share would be $82.6 million.[11]

15. Q What materials does the Company provide in support of its proposal regarding the Valmy plant?

NV Energy provided the following materials in this application in support of its Valmy proposal:

1. A narrative explanation of the proposal in Volume 1,
2. Testimony explaining the proposal in Volume 2,
3. An updated 2023 transmission system reliability Study (Valmy Must Run Requirement Study),
4. A study on resource economics of certain options for Valmy (Valmy LSAP 2023 Update),

[9] Application, Vol. 1 at 90 (Table GEN-4). Table GEN-4 was redacted in the original application, but the Company later made Table GEN-4 public on December 4, 2023.
[10] *Id.* at 88.
[11] *Id.* at 89.

5. An earlier 2018 LSAP analysis for Valmy, and

6. A 2023 Key Decision Report explaining the Company's Valmy proposal.

In the supporting materials, NV Energy evaluates many scenarios of transmission system reliability, as well as a few scenarios on the economics of replacing or repowering Valmy. But none of these studies provide sufficient support for the Company's proposal. For example, the 2023 Valmy Must Run Study finds that, "[w]ith adequate generation support and additional transmission to offset significant load growth, the transmission system can withstand the retirement of Valmy." [12] Thus, the study does not provide adequate support for the Company's plans to run Valmy through 2049. I will describe and assess these materials in the sections below in more detail.

16. Q Please describe the support for the Valmy proposal that NV Energy provides in the narrative in Volume 1 of its application.

A In the narrative in Volume 1 of the application, NV Energy relies heavily on the studies filed with the application (items 3 through 6 above) to support its Valmy proposal. In addition, the narrative provides general support for the Valmy proposal, including:

- A "need for voltage support and available around-the-clock generation in the Carlin Trend load pocket," and for "operating or quick-start generation" located at or near Valmy until Greenlink West is in service, citing the 2023 Must Run Study provided with the application;[13]

[12] Application, Vol. 4 at 19.
[13] Application, Vol. 1 at 12, 32.

- Cancellation of the Hot Pot and Iron Point projects previously intended to help replace Valmy;[14]

- The Good Neighbor Plan's strict limits on the amount of NO_X that can be emitted at Valmy during the ozone season from May through September. NV Energy states that these restrictions will phase in during 2026 and 2027, with a 50 percent reduction of the 2021 emissions rate for each unit required in 2026 and a "fully controlled emission rate of 0.05 lb/MMBtu, commensurate with SCR retrofits" beginning in 2027;[15]

- Recent issues with coal supply procurement and ongoing coal fuel supply risk;

- The Company's carbon reduction goals;[16] and

- Economic analysis of portfolios that include either Valmy coal to gas conversion or replacement of Valmy with two combustion turbines.[17]

17. Q Does NV Energy provide adequate support for the Company's Valmy proposal in the narrative?

A No. The narrative summarizes other studies provided with the Company's filing (items 3 through 6 listed above) and relies on these studies to support the Company's assertion that the only viable options for Valmy are (1) the Company's proposal to repower Valmy, install SCR, and run Valmy through 2049; or (2) an option to replace Valmy with two

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[14] *Id.* at 32.
[15] *Id.* at 69.
[16] *Id.* at 34.
[17] *Id.* at 149–150.

combustion turbines by summer 2027. The economic analysis in the narrative begins with these restrictive assumptions.[18] However, the Valmy studies that the narrative references do not completely support this interpretation; they could also be consistent with a variety of other plans not considered in the narrative, as I will explain.

In the narrative, the Company asserts that under Good Neighbor Plan requirements, NO_X-reducing equipment will be required at Valmy to maintain must-run status during the ozone season, but it does not provide analysis to support this claim or assess whether SNCR would be adequate. According to the Nevada Regional Haze State Implementation Plan ("SIP"), the cost of SNCR is one-tenth the cost of SCR for Valmy.[19]

The Company states elsewhere in the narrative that it is "reasonably anticipated" that coal-fired must-run operation at Valmy could likely be sustained through the 2026 ozone season without SCR installation.[20] In the 2027 ozone season however, NO_X restrictions would no longer allow must-run coal operation at Valmy.[21] Thus, it appears possible that the Company's schedule for gas conversion and SCR at Valmy could be pushed back one year from completion in May 2026 to completion in May 2027 to facilitate further study of alternatives.[22]

The Valmy Must Run Study indicates that the transmission system can withstand the retirement of Valmy, but not until Greenlink West is completed or additional generation is added to the system.[23] If the Company can bring additional transmission and generation online as expected, then the usefulness of SCR and capital projects for

[18] *Id.* at 175–183.
[19] Nev. Div. of Env't Prot. and Nev. Dep't of Conservation & Nat. Res., *Regional Haze SIP For the Second Planning Period* at 5-12 (Aug. 2022), *available at* https://ndep.nv.gov/uploads/air-plan_mod-docs/All_SIP_Chapters.pdf, excerpt attached as Attach. RA-3.
[20] Application, Vol. 1 at 70.
[21] *Id.*
[22] *See id.* at 92.
[23] Application, Vol. 4 at 19.

continued operation at Valmy could be greatly reduced during the three year period from 2026 through 2028.

Finally, the economic analysis provided in the narrative appears to greatly undervalue the potential to reduce portfolio costs by selling renewable energy in market transactions. The Company apparently assumes that any renewable energy not needed for retail customers is curtailed, instead of being sold at market. The Company refers to this energy as "dump energy."[24] In the later years of one portfolio, "dump generation" reaches almost 16,000 GWh a year and accounts for 32 percent of the total amount of renewable generation.[25] This unrealistically reduces the ranking of renewable energy portfolios in the application. In actual operations, the Company should sell this energy to the market to reduce costs for customers.

18. Q Please describe the support for the Valmy proposal that NV Energy provided in testimony in Volume 2 of the application.

A In the prefiled testimony in Volume 2 of the application, NV Energy provides general reasoning in support of the Valmy proposal but does not provide new analysis. In the testimony, the Company points to the other studies included with the application for support.

19. Q Please assess the support for the Valmy proposal in the testimony of Ryan Atkins.

A Ryan Atkins refers to the Must Run Study to support claims that there are "two feasible options support the retirement of coal generation at Valmy and to support the continuing

[24] Application, Vol. 1 at 163.
[25] Application, Vol. 5 at 13–14.

need for a firm dispatchable resource: the refueling of Valmy to burn natural gas or the construction of new natural gas-fired peaking units at the Valmy site."[26]

The Must Run Study does find that generation at Valmy is required "until Greenlink West is complete or additional generation is added to Sierra's system."[27] However, this conclusion does not support the Company's proposal for SCR or capital projects for continued operation at Valmy. In fact, the Must Run Study concludes, "[w]ith adequate generation support and additional transmission to offset significant load growth, the transmission system can withstand the retirement of Valmy."[28]

20. Q Please assess the support for the Valmy proposal in the testimony of Matthew Johns.

A Matthew Johns generally describes the impacts that the Regional Haze Rule, Good Neighbor Plan, and Clean Air Act regulations may have on the Company's coal and gas generation. Johns does not provide any concrete analysis showing that SCR or gas conversion at Valmy is required to support compliance with these regulations.[29]

21. Q Please assess the support for the Valmy proposal in the testimony of John Lescenski.

A John Lescenski describes the Company's updated 2023 LSAP and explains that it finds conversion to gas and operation through 2049 to be the Company's preferred plan. However, as I will explain below, the 2023 LSAP considers only four resource options and should not be considered a rigorous study of the Company's options.

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[26] Application, Vol. 2 at 11–12.
[27] Application, Vol. 4 at 19.
[28] *Id.*
[29] Application, Vol. 2 at 55–56.

22. Q Please assess the support for the Valmy proposal in the testimony of Charles Pottey.

A Charles Pottey relies on the 2023 Must Run Study to support "the need for the existing Valmy area generation must-run procedure" until Greenlink West is completed, when "the must-run procedure may be able to be suspended subject to load growth and planned outages."[30] While this may be an accurate description of the Must Run Study, neither Pottey's testimony nor the Must Run Study actually demonstrate a need to limit the Company's options to either Valmy repowering with SCR or replacement of Valmy with two combustion turbines. Nor do they support running Valmy through 2049.

23. Q Please assess the support for the Valmy proposal in the testimony of Kimberly Williams.

A Kimberly Williams describes the 2023 Must Run Study as requiring "generation at or near Valmy that must be online or able to start quickly in the event of a transmission outage, and able to continue to generate until the outage is corrected."[31] Williams notes that even after the in-service date of Greenlink West, transmission reliability issues could continue to create the need for must-run generation at Valmy to avoid potential load shedding.[32] However, Williams does not mention that, in the Must Run Study, the addition of Greenlink North resolves the identified reliability violations, even in the absence of Valmy and Newmont Mining Company's TS Power Plant ("TSPP") as I will discuss further below.

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[30] *Id.* at 143:20-21, 144:13-14.
[31] *Id.* at 173:17-19.
[32] *Id.* at 173–174.

24. Q Please describe the 2023 Valmy Must Run Study and its findings.

The 2023 Must Run Study is an update to the transmission studies in the 2018 Valmy LSAP. In the updated study, the Company evaluates transmission system reliability under peak summer load conditions in 2025, before the Greenlink West transmission project is in service, assuming that Valmy and Newmont TSPP are both offline. The Company includes the addition of approximately 537 MW of forecasted high voltage distribution ("HVD") customer load, representing load forecasts from currently contracted customers.[33]

This study represents the system in a state of peak stress. The Company models transmission outages during this stressed state to test transmission system reliability. The modeling includes P1 scenarios, which usually involve one major transmission system outage (N-1), and also P6 scenarios, which usually involve two transmission line outages (N-1-1).

In the study, NV Energy looks at four cases in 2025.[34] The Company's modeling identifies some reliability issues, along with the solutions necessary to resolve them.[35] The solutions often require additional generation to be added near Valmy or Tracy. The Company concludes that in 2025, "[t]o fully support the contracted load for new customers, generation at Valmy will need to be retained or replaced with 24 hour dispatchable generation[]."[36]

[33] Application, Vol. 4 at 6.
[34] *Id.* at 11–12.
[35] *Id.* at 18.
[36] *Id.* at 14.

The Company considers an additional 2027 scenario, after Greenlink West is in service.[37] The Company finds that after Greenlink West is in service, P1 scenarios either result in no voltage violations, or they result in violations that can be managed with the installation of new capacitor banks.[38] In a P6 scenario where the loss of Greenlink West is followed by the loss of a second major line, "[l]oad shedding may be required." [39] However, it appears that this potential load shedding under the loss of two separate transmission lines may be in compliance with North American Electric Reliability Corporation ("NERC") standards, since it is associated with a NERC Under Voltage Load Shedding ("UVLS") operation.[40]

Importantly, the Company finds that all transmission system issues identified in Appendix C are resolved with the addition of Greenlink North.[41]

25. Q Does the 2023 Valmy Must Run Study provide adequate support for the Company's Valmy proposal?

A No. In this study, NV Energy finds that, under peak conditions, 24-hour dispatchable generation near Valmy is necessary for transmission system reliability before Greenlink West is in place.[42] However, the addition of Greenlink West resolves many of the identified reliability issues, and the further addition of Greenlink North resolves the

[37] *Id.* at 12.
[38] *Id.* at 15.
[39] Application, Vol. 4 at 15, 110.
[40] *See* NERC, PRC-010-1 – Undervoltage Load Shedding, *available at* https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-010-1.pdf (last visited Dec. 18, 2023), attached as Attach. RA-4.
[41] Application, Vol. 4 at 16 ("Following the completion of Greenlink North, the above P6 limitation would no longer be a valid concern.").
[42] *Id.* at 14.

remaining identified issue. Greenlink West is currently planned for service in May 2027 and Greenlink North is expected in December 2028.[43]

The Must Run Study provides insight into the grid in 2025 and 2027, but it does not support the Company's plans to run Valmy through 2049. As soon as Greenlink North is in service in 2028, the study indicates no further transmission system issues resulting from Valmy retirement.[44]

Further, the Valmy Must Run Study looks only at peak conditions. It does not assess whether 24-hour dispatchable generation at Valmy is necessary under normal load conditions. In the study, the Company concludes that Valmy should not be retired until Greenlink West is complete or additional generation is added to Sierra's system,[45] but the Must Run Study does not actually mention whether or when must-run status should be required at Valmy. Thus, while the study may indirectly provide support for placing one Valmy unit into must-run status during peak conditions to ensure that one unit is running at all times, it does not provide adequate support for placing Valmy units in must-run status during off-peak times of year.

The Must Run Study does not include consideration of whether SCR at Valmy would be required after the Good Neighbor Plan begins to require significant NO_X emissions reductions in 2026.[46] The study therefore cannot be used to support the Company's plans to install SCR at Valmy without further analysis, which the Company has not provided.

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[43] NV Energy Response to SC DRs 4-01, 4-02 (Attach. RA-2).
[44] *See* Application, Vol. 4 at 16.
[45] *Id.* at 19.
[46] *See* Federal 'Good Neighbor Plan' for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 33,654, 33,654–36,666, 36,754–36,844 (June 5, 2023), *available at* https://www.federalregister.gov/documents/2023/06/05/2023-05744/federal-good-neighbor-

26. Q Please describe the support for the Valmy proposal that NV Energy provided in the 2023 Valmy LSAP Update.

A The 2023 Valmy LSAP Update looks at the cost of four different Valmy scenarios, without assessing transmission system reliability. Two scenarios assess the cost of a portfolio that converts the existing Valmy units to gas, with different allocations between NV Energy and Idaho Power.[47] A third scenario assesses the cost of replacing Valmy with new simple cycle combustion turbines.[48] The fourth scenario assesses the cost of replacing Valmy with solar plus battery storage.[49]

The LSAP update finds that keeping Valmy online and converting the plant to gas with SCR is expected to be less expensive than either of the two other replacement scenarios considered. In comparison, the scenario that retires Valmy and replaces it with combustion turbines has similar costs to the repowering scenario.[50] The solar plus storage scenario appears significantly more expensive than the other options, however it is not clear whether the Company included a realistic estimate of the value of renewable energy market sales, or unrealistically assumed that any renewable energy generation in excess of retail load would be curtailed.[51]

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plan-for-the-2015-ozone-national-ambient-air-quality-standards, excerpt attached as Attach. RA-5.

[47] Application, Vol. 3 at 27.

[48] *Id.*

[49] *Id.* at 28.

[50] *Id.* at 30.

[51] *Id.*

27. Q Does the 2023 Valmy LSAP provide adequate support for the Company's Valmy plans?

A No. NV Energy evaluated only two alternative scenarios to the Valmy gas conversion, and these do not represent the full range of alternatives to the Company's plan. This study does not optimize a resource portfolio to find the lowest-cost alternative to continued operation of, and investment in, Valmy.

The study also does not assess whether SCR installation would be required to meet Good Neighbor Plan requirements.

If the Company excluded market sales revenues from the analysis, it would create a substantial bias against portfolios with renewable energy, resulting in excessively high costs for the solar plus storage scenario.

28. Q Please describe the 2023 Key Decision Report.

A In the Key Decision Report ("KDR"), NV Energy assesses four Valmy operational scenarios for transmission system reliability.[52] Based on these assessments, the KDR discusses the Company's decision to establish must-run conditions for Valmy units (a) when Newmont TSPP is online and (b) when Newmont TSPP is offline. When Newmont TSPP is online, the report recommends placing either Valmy Unit 1 or Valmy Unit 2 in Reliability Must Run ("RMR") status.[53] When Newmont TSPP is offline, the report recommends placing both units in RMR status.[54]

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[52] Application, Vol. 4 at 227–228.
[53] *Id.* at 221.
[54] *Id.*

29. Q Does the KDR provide adequate support for the Company's proposal?

A No. The KDR looks at the system before Greenlink West is in service. Therefore, it would appear that the KDR's findings regarding the need for must-run status at Valmy cannot be extrapolated beyond the in-service date of Greenlink West.

In addition, the KDR reports that a plan without Valmy 1 would be NERC-compliant, even though it would have "a high level" of customer risk.[55] The fact that the Company did not further evaluate a plan without Valmy 1, despite the savings that could be achieved by avoiding investment in Valmy 1, highlights that NV Energy is planning to a higher-than-necessary standard for Carlin Trend customers.

30. Q Please describe the 2018 Valmy LSAP in Volume 4 of the application.

A The 2018 LSAP was created by NV Energy to evaluate the potential to retire Valmy in 2025 and maintain system reliability. In the 2018 LSAP, NV Energy identifies the additional resources needed to support a 2025 Valmy retirement. In the study, the Company looks at ten main scenarios, including scenarios without Valmy and Newmont Mining Company's TSPP, high system import scenarios, and a scenario with 600+ MW of load growth in the Tracy area.[56]

In the 2018 LSAP, NV Energy evaluated these scenarios and found that the system impacts of 2025 Valmy retirement could be mitigated in each scenario with the appropriate combination of reactive support, new transmission, and new solar PV and battery energy storage.[57] In the most challenging scenario, Case 10, NV Energy assumed

[55] *Id.* at 227.
[56] *Id.* at 136–137.
[57] *Id.* at 137–148.

628 MW of load growth in the Tracy area, with Valmy and Newmont TSPP offline under peak summer conditions.[58] NV Energy finds that a new 345 kV line and the installation of a static VAR compensator ("SVC") at Valmy would resolve reliability issues.[59]

The study concludes that "[w]ith adequate reactive support and additional transmission to offset significant load growth, the transmission system can withstand the retirement of Valmy."[60]

31. Q Does the 2018 Valmy LSAP support the Company's Valmy proposal?

A The 2018 LSAP does not support the Company's proposal for gas conversion, SCR installation, and continued generation at Valmy through 2049. Quite the opposite, the 2018 LSAP finds that 2025 Valmy retirement can be supported by the right combination of investments in the transmission grid and planned new sources of generation.

Given that the 2018 LSAP has been available to the Company for several years, it is not clear why the Company has implemented "[a]lmost none" of the recommended investments in, or electrically close to, the Carlin Trend load pocket region of the transmission grid.[61]

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[58] Application, Vol. 4 at 146.
[59] *Id.* at 147.
[60] *Id.* at 160.
[61] *Id.* at 225.

32. Q What is your conclusion after reviewing the materials provided in support of the Company's plans for Valmy Units 1 and 2?

A While the materials summarized above provide useful information about a few potential Valmy retirement scenarios, they do not provide adequate support for the Company's proposal to spend $82.6 million on Valmy gas conversion, SCR, and continued operation through 2049.[62] In fact, the application materials show that with adequate new resources, the transmission system can be operated reliably without coal or gas generation at Valmy.

33. Q Besides the lack of support for the Company's Valmy proposal, what other concerns do you have about this approach to Valmy Units 1 and 2?

I am concerned that spending $82.6 million on gas conversion, SCR installation, and continued operations at Valmy Units 1 and 2 will make it more difficult for the Company to retire the units, and risks creating a stranded asset. The Company has not done sufficient analysis to show that the Company's proposal is a better option for retail customers than retiring Valmy once the system can be made reliable through other new transmission and generation investments. Locking ratepayers into more costs now will make accelerated depreciation and retirement at Valmy more expensive in the future. Additionally, adding to the Company's gas generation portfolio will expose customers to the increased fuel price risk associated with global markets for natural gas.

Another concern is that the Company is planning to support reliability for its DOS customers in the Carlin Trend load pocket by incurring expenses at the Valmy plant for which DOS customers will not pay a share proportionate to their contribution to cost causation. NV Energy is planning to a reliability standard that exceeds NERC requirements for Carlin Trend customers, citing safety concerns at underground mines.[63]

[62] *See* Application, Vol. 1 at 89.
[63] Application, Vol. 4 at 222, 227.

Approximately 71 percent of the energy currently delivered to Carlin Trend load pocket is for DOS customers who do not pay for expenses associated with electric generators in their NV Energy DOS rate.[64] The extent to which these customers may pay for some costs of upgrading Valmy through their FERC OATT for transmission service through NV Energy is unclear, but seems unlikely to fully reflect their contribution to cost causation at Valmy.[65]

34. Q Is there another approach to Carlin Trend reliability that you think would be fairer to retail ratepayers?

A The Company should carefully consider whether major investments in Valmy are necessary at this time, when a transmission solution to reliability issues at the Carlin Trend load pocket is only a few years away. The 2023 Valmy Must Run Study found that with Greenlink West and Greenlink North both in service, and with a few transmission system upgrades, the P1 events identified would be resolved and the P6 event identified would no longer be a valid concern.[66] Greenlink West is expected to be in service in May 2027, and Greenlink North in December 2028.[67]

To the extent that Carlin Trend customers have safety and reliability needs above the Company's normal standards for reliable transmission service, these customers should invest in backup generation or storage.

[64] NV Energy's Response to SC DR 3-24 (Attach. RA-2).
[65] Sierra Club has sent a data request to NV Energy regarding any contribution of Carlin Trend DOS customers to the cost of the Company's Valmy proposal via the OATT. The Company's response to that request is pending.
[66] *See* Application, Vol. 4 at 15–16, 110.
[67] NV Energy Response to SC DRs 4-01, 4-02 (Attach. RA-2).

35. Q Do you have suggestions for alternatives to the Company's Valmy proposal?

A The Company has a challenging task in ensuring reliability at the Carlin Trend load pocket during 2026 and 2027 before Greenlink West is in place and as the Good Neighbor Plan's strict NO_X reduction requirements go into effect. However, after Greenlink North is in place, the 2023 Must Run Study indicates there will no longer be a need for generation at Valmy to support NERC standards in the Carlin Trend load pocket.[68]

The Company's application has not shown any need to operate Valmy through 2049. Instead of operating Valmy through 2049, it may be best to seek options to operate Valmy only through 2027 or 2028, and avoid making investments in gas conversion, continuing operations, and SCR at Valmy. Capital expenditures for continued operation through 2049 are a substantial part of the Company's proposal at $32.25 million,[69] and the application has established no need for generation through 2049.

It is NV Energy's responsibility to adequately evaluate resource plans, and to identify a plan for Valmy that meets system reliability needs while both reducing costs and allocating costs fairly. While the Company needs to maintain a NERC-compliant transmission system, it is questionable whether the Company should go above and beyond NERC requirements to provide even greater reliability to Carlin Trend customers. There may be measures the Company can take, for a limited time until Greenlink North is in place, to ensure adequate reliability in the Carlin Trend load pocket without making major investments in the 40-year-old Valmy plant. NV Energy should perform further analysis to evaluate this possibility.

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[68] Application, Vol. 4 at 16.

[69] Application, Vol. 1 at 90 (Table GEN-4). Table GEN-4 was redacted in the original application, but the Company later made Table GEN-4 public on December 4, 2023.

During the challenging years before Greenlink North is in place, the Company should create savings for customers and maintain transmission system reliability through alternatives to gas conversion, continued operations, and SCR at Valmy. Some alternatives that NV Energy should consider include:

- Perform an update to the 2023 Valmy Must Run Study to assess whether the Valmy units could be placed on standby during off-peak months in 2026–2028. This could help reduce Valmy's NO_X emissions during the Ozone Season (May through September) enough to comply with the Good Neighbor Plan without SCR installation. The 2023 Must Run Study did not assess off-peak months.

- Study transmission system reliability after Greenlink West is in service, with the storage output at Sierra Solar Battery Energy Storage System held back intentionally to provide support for reliability needs 24 hours a day. This could provide several hours of lead time for the Company to implement load management or other changes to maintain transmission system reliability in the absence of Valmy, even before Greenlink North is in place.

- Retire one Valmy unit in 2025 or else place a unit on standby and avoid the cost of gas conversion and SCR at one Valmy unit.

- To maintain control of two sources of generation near Carlin Trend, negotiate a deal with Newmont for NV Energy to operate TSPP until Greenlink North is in place.[70]

- Assess the installation of SNCR instead of SCR to meet the requirements of the Good Neighbor Plan at a lower cost.

[70] NV Energy asserts that "[t]o mitigate reliability issues in the area, two sources of generation need to be under NV Energy control." *See* Application, Vol. 4 at 223.

- Enroll Carlin Trend customers in a demand response program that allows customers to receive substantial compensation for curtailment before Greenlink North is in place.

- Allow Carlin Trend DOS customers to install their own backup generation or local battery storage resources (of sufficient size and duration) to safely shut down mining operations in the event of load shedding before Greenlink North is in place, rather than the Company planning to an unnecessarily high standard of reliability for Carlin Trend DOS customers.

36. Q What is your recommendation regarding the Company's application with respect to Valmy?

A First, I recommend that the Commission find the portion of the Company's application that proposes gas conversion at Valmy, SCR installation, and operation of the plant until 2049 to be inadequate. The Company has not shown that this is the best option for customers.

Second, the Company should perform more analysis on Valmy alternatives. The Company has reported that the Valmy plant can likely satisfy a must-run requirement in 2026 without gas conversion or NO_X controls, while remaining within the Good Neighbor Plan's NO_X limitations.[71] This should allow enough time for the Company to perform more analysis before it makes a decision.

First, the Company should provide the Commission with a report showing the potential to avoid a portion of the capital costs associated with preparing the Valmy plant for continued operation through 2049, since Valmy will become less important for system reliability after Greenlink North is in place (expected in December 2028.) These capital

[71] Application, Vol. 1 at 70.

projects for continued operation comprise 40 percent of the Company's total proposed Valmy investment, so this step could reduce costs significantly.

Second, the Company should provide the Commission with a report on the potential to install SNCR instead of SCR at one or both Valmy units to minimize costs for customers while meeting Good Neighbor Plan and NERC reliability requirements.

Third, the Company should report on the potential for demand response, customer-sited backup generation or storage, negotiation with Newmont for operation of TSPP until new transmission is in place, and other options to avoid costs associated with long-term operation of the Valmy plant.

IV. TRACY UNITS 4 AND 5

37. Q Please describe Tracy Generating Station.

A Tracy Generating Station is a 773 MW gas-fired power plant located east of Reno, Nevada.[72] Tracy Units 4 and 5 are operated together as a gas-fired combined-cycle generator that provides 104 MW of capacity.[73] NV Energy owns 100 percent of Tracy Units 4 and 5. The units were built in 1996.[74]

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[72] *Id.* at 63.
[73] *Id.* at 64 (Table GEN-1); NV Energy Response to SC DR 5-06 (Attach. RA-2).
[74] Application, Vol. 1 at 64 (Table GEN-1).

38. Q Prior to this application, what was the planned retirement date for Tracy?

A NV Energy's pre-application planned retirement date for Tracy Units 4 and 5 is 2031.[75] The Title V air quality permit for Tracy Units 4 and 5 imposes a federally enforceable retirement date of December 31, 2031.[76]

39. Q Why has NV Energy filed this update and proposed modifications for Tracy Units 4 and 5?

A The Tracy LSAP states that the nearing retirement date and the Good Neighbor Plan's NO_X emissions limitations caused the need for an evaluation of the operating life for Tracy Units 4 and 5.[77]

40. Q What is NV Energy requesting in this docket related to Tracy Units 4 and 5?

A NV Energy is requesting to install SCR at Tracy Units 4 and 5 and to extend operations until 2049. This is 18 years beyond the previously planned 2031 retirement date. The expected cost of SCR installation at Tracy Units 4 and 5 is $12 million, and the expected cost of capital expenditures for continuing operation through 2049 is $41.5 million.[78] The Company's analysis predicts that this proposal will save customers approximately $18 million over 28 years, as compared to retiring Tracy Units 4 and 5 in December, 2031.[79]

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[75] *Id.*
[76] *Id.* at 67.
[77] *See* Application, Vol. 3 at 106–109.
[78] *See* Attachment to NV Energy Response to Staff DR 01, attached as Attach. RA-6.
[79] Application, Vol. 3 at 112–113.

41. Q Please describe the support for the Tracy Units 4 and 5 proposal provided in the Company's application.

A The application includes a narrative discussion in Volume 1, Testimony in Volume 2, and the Tracy LSAP in Volume 3.

42. Q Please describe the support for the Tracy Units 4 and 5 proposal provided in the Narrative.

A The narrative states that SCR and continued operation at Tracy Units 4 and 5 is marginally less expensive than retirement in 2031, citing the Tracy LSAP.[80] The narrative requests approval of the Company's proposal for Tracy Units 4 and 5 at this time.

43. Q Please describe the support for the Tracy proposal provided in the Tracy LSAP.

A The Tracy LSAP considers only two scenarios: retirement of Tracy Units 4 and 5 in 2031 or continued operation through 2049 with SCR installation. The study finds that installing SCR and running the units through 2049 is marginally less expensive by about $18 million over 28 years.[81]

44. Q Do you agree that approval of the Company's proposal for Tracy Units 4 and 5 should be approved now?

A No. The Commission should not approve the Company's proposal for Tracy Units 4 and 5 at this time. The economics of Tracy Units 4 and 5 have been shown to be marginal,

[80] Application, Vol. 1 at 184.
[81] Application, Vol. 3 at 113.

and there appears to be ample time for the Company to act carefully. The Company proposes for SCR construction to begin in October of 2027 and take only three months.[82] Retirement of Tracy Units 4 and 5 is not legally required until December 31, 2031.[83]

45. Q What are the risks of installing SCR at Tracy Units 4 and 5 now?

A Installing SCR at Tracy Units 4 and 5 at this time is unnecessary and risky because of the marginal economics of keeping the units online. If SCR is installed as planned, and then additional unexpected expenses occur or gas prices increase more than expected, it will be too late to avoid the cost of SCR installation and save that money for customers by retiring Tracy Units 4 and 5 in 2031 as planned. Should the economics of the units tilt strongly in favor of retirement after the installation of SCR, the cost of the SCR would become a stranded asset potentially borne by ratepayers.

Additional expenses could occur because of the age of the plant, or because of future carbon regulation. Although the EPA's proposed Clean Air Act Section 111(d) carbon rules likely will not apply to Tracy as a generator under 300 MW, the risk of further carbon regulation in the future is high. Customers will be more likely to benefit from investments in new, clean generation instead of investment in an older combined cycle generator that is "nearing the end of its design life."[84]

[82] Application, Vol. 1 at 94 (Table GEN-8).
[83] *Id.* at 67.
[84] Application, Vol. 3 at 109.

46. Q What alternatives for Tracy Units 4 and 5 should NV Energy have considered in this amendment?

A NV Energy has the option to meet Good Neighbor Plan requirements at Tracy Units 4 and 5 through reduced dispatch or installation of much less expensive SNCR technology. Either approach would avoid a significant capital outlay of $12 million for SCR.[85]

NV Energy should not perform capital upgrades for continued operation at Tracy Units 4 and 5 at this time. With a 2031 planned retirement date, there is plenty of time to carefully consider this decision and observe whether the units' economics improve or decline.

Regarding the Regional Haze Program, the Company has the option of including a plan for reduced dispatch and/or SNCR installation at Tracy Units 4 and 5 in an amended Nevada Regional Haze SIP. The Company could also retire the Tracy units in 2031 as currently required.

47. Q What do you recommend regarding Tracy Units 4 and 5?

A The Commission should find the portion of the Company's application that proposes SCR installation at Tracy Units 4 and 5 and continued operation of those units until 2049 to be inadequate. The marginal benefits shown do not outweigh the risks of a significant investment in Tracy Units 4 and 5.

NV Energy has not demonstrated that it is in the best interest of customers to install SCR at Tracy Units 4 and 5 at this time or to extend the units' operating lives to 2049. The units are 27 years old already.[86] If it becomes apparent before 2031 that operating the units until 2049 would result in unexpected costs, that could tilt the economic analysis in

[85] *See* Attachment to NV Energy Response to Staff Data Request 01 (Attach. RA-6).
[86] Application, Vol. 3 at 109.

favor of a 2031 retirement. The Tracy units could require unexpected repairs, or a future carbon policy could impact the units' economics.

48. Q Does this conclude your testimony?

A Yes.

AFFIRMATION

STATE OF NEVADA)
: ss.
CARSON CITY)

Pursuant to the requirements of NRS 53.045(1) and NAC 703.710, I, Rose Anderson, swear that I am the person identified in the attached Direct Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

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

Executed on: December 19, 2023 */s/ Rose Anderson*

ATTACHMENT RA-5

NV Energy's 5th Amendment to its 2021 IRP,

Docket No. 23-08015 (Excerpt)

Vol. 1, Exhibit A – Narrative at 18, 62, 148

Vol. 3, GEN-3 at 19-20

Vol. 4, TRAN-1 at 14, 17, 108

Vol. 4, TRAN-5 at 1, 5

FILED WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA - 8/25/2023

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the Fifth Amendment to the 2021 Joint Integrated Resource Plan.	Docket No. 23-08___

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SECTION 3. LOAD FORECAST

The load forecast for the Fifth Amendment to the 2021 Joint IRP is identical to the load forecast that was approved on March 23, 2023 by the Order in Docket No. 22-09006 by the Commission, accepting the stipulation approving the latest load forecast. The load forecast will be updated in the 2024 triennial IRP for both population and economics inputs, reflecting the stipulated agreement in Docket No. 22-09006, as well as new major project load additions.

Load Forecast Summary: Consistent with NAC § 704.923(2) and NAC § 704.9516(e), Table LF-1 is a summary of the forecasted peak loads and energy consumption from 2023 through 2042 from the load forecast approved in Docket No. 22-09006. It is important to note that NV Energy peak demands may be lower than the combined total of Sierra and Nevada Power due to diversity between the two systems. i.e., they do not necessarily peak at the same time.

TABLE LF-1
NATIVE ENERGY (GWH) AND ANNUAL PEAK (MW)

	Native Energy (GWh)			Peak (MW)		
Year	NVE	NPC	Sierra	NVE	NPC	Sierra
2023	32,651	22,514	10,136	7,950	6,131	1,966
2024	33,462	22,971	10,492	8,133	6,222	2,015
2025	34,145	23,346	10,799	8,217	6,319	2,068
2026	34,092	23,569	10,523	8,267	6,371	2,049
2027	34,594	23,780	10,814	8,293	6,430	2,099
2028	35,162	24,059	11,102	8,536	6,524	2,142
2029	35,639	24,314	11,324	8,608	6,591	2,184
2030	35,906	24,494	11,411	8,777	6,645	2,206
2031	36,157	24,669	11,488	8,770	6,693	2,234
2032	36,439	24,881	11,558	8,826	6,742	2,257
2033	36,669	25,047	11,622	8,894	6,794	2,275
2034	36,946	25,261	11,686	9,026	6,879	2,299
2035	37,227	25,480	11,747	9,061	6,918	2,318
2036	37,556	25,743	11,812	9,181	6,986	2,341
2037	37,806	25,937	11,869	9,281	7,050	2,362
2038	38,082	26,157	11,925	9,244	7,106	2,380
2039	38,362	26,379	11,982	9,377	7,174	2,394
2040	38,673	26,638	12,035	9,477	7,257	2,411
2041	38,912	26,830	12,082	9,679	7,333	2,429
2042	39,199	27,065	12,134	9,667	7,404	2,450
CAGR						
23-33	1.2%	1.1%	1.4%	1.1%	1.0%	1.5%
32-42	0.7%	0.8%	0.5%	0.9%	0.9%	0.8%

Notes:
(1) NVE Peak adjusted for diversity.
(2) Hourly value of Company coincident peak

the onsite landfill will be closed, and post-closure monitoring will commence per CCR regulations and state permit requirements.

The most recent decommissioning cost estimate was prepared for Valmy in 2018 and included in the 2022 Sierra electric depreciation filing (Docket No. 22-06015). Using this estimate as a basis for order of magnitude costs, it is expected that the cost to complete this partial decommissioning effort will range from $10 to $15 million total, with Sierra's share being 50 percent. A detailed estimate will be prepared as part of decommissioning planning. Post-closure landfill maintenance and monitoring and reporting will continue for a period of 30 years.

The costs for the retirement of coal operations at Valmy are not included in the project costs presented above and would be collected and recovered through a regulatory asset similar to the retirement of other coal facilities within the Companies' fleet. The undepreciated net book value for assets that are retired, and the related stranded inventory will also be included in the regulatory asset account.

Engineering and Design Development

As described in the LSAP, the project costs are based on the engineering study completed by Burns and McDonnell and the SCR costs are based on budgetary estimates provided by an SCR provider. As shown in the schedule that follows, Sierra intends to contract with an Owner's Engineer and complete the preliminary engineering and development of the Request for Proposal ("RFP") for the Engineering, Procurement and Construction ("EPC") in 2023.

Permits

As discussed in subsection B, Environmental Regulations Impacts, revision of the RHR SIP and Valmy Title V air permit modifications are being pursued in parallel with this filing. In the event the Valmy Natural Gas Conversion project is not approved by the Commission, the Companies anticipate that NDEP will re-file its RHR SIP revision and maintain the current Title V air permit with the legally enforceable retirement date of December 31, 2028.

Natural Gas Supply

The Valmy coal-to-gas conversion will require an interconnection to a new intrastate line in Humboldt County that will access supplies from the Ruby Pipeline. Pinyon Pipeline, LLC, a new pipeline affiliated with the Ruby Pipeline, has proposed a lateral that will supply natural gas to the Valmy Station to support this project. A proposed lateral and associated gas metering would be capable of delivering about 7,100 MMBtus hourly and 170,000 MMBtus daily, with guaranteed pressures of 650 psig and above.

analyzed in this project can be charged by the grid as opposed to by the PV unit only. In addition, this project contributes to both Companies' RPS and capacity needs. Ownership is split 60 percent to Nevada Power and 40 percent to Sierra.

- ***Iron Point.*** Replaces Base Case placeholder resources the updated RFP bid for the Iron Point project which consists of 250 MW of paired PV and BESS located in the Valmy area. This project has an in-service date of 2026 for both PV and BESS. The BESS analyzed in this project can be charged by the grid as opposed to by the PV unit only. In addition, this project contributes to both Companies' RPS and capacity needs. Ownership is split 60 percent to Nevada Power and 40 percent to Sierra.
- ***Hot Pot and Iron Point.*** A combination of the two projects listed above replaces Base Case placeholder resources. A different price for the PV generation was offered if both projects were taken. The in-service dates were to remain in 2026. Prices for the BESS were unchanged. These projects contribute to both Companies' RPS and capacity needs. Ownership is split 60 percent to Nevada Power and 40 percent to Sierra.

The L&R tables for the individual project screening are provided in Technical Appendix ECON-5. The redacted cost summaries and load balances from the production cost model runs are included in Technical Appendix ECON-4. The CER analysis for each case is part of Technical Appendices ECON-6 and ECON-7.

The PWRR results of the individual project screening analysis are shown in Figure EA-7 below.

FIGURE EA-7
RESULTS OF INDIVIDUAL PROJECT SCREENING

	20 Year PWRR 2024-2043 (million $)		28 Year PWRR 2024-2051 (million $)		20 Year PWRR Change vs Least Cost Case (million $)		28 Year PWRR Change vs Least Cost Case (million $)	
Base	$	22,031	$	28,488	$	147	$	265
Sierra Solar	$	22,073	$	28,531	$	189	$	308
Hot Pot	$	22,127	$	28,577	$	243	$	354
Iron Point	$	22,124	$	28,583	$	240	$	360
Hot Pot and Iron Point	$	22,403	$	28,887	$	519	$	664
Valmy BESS	$	21,948	$	28,354	$	64	$	131
2 Valmy CTs	$	21,884	$	28,223	$	-	$	-

Key findings of the individual projects screening are provided below.

- *Valmy 2-CTs* has the lowest PWRR. The case supplies a portion of the Companies' capacity need but none of the renewable credits. The dispatchable nature of the project provides

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December 31, 2025, both Sierra and IPCo retire their interests in the plants.

4.2 Option 1 - Retire both Valmy Units by 12/31/2025 and replace with 2 peaking units (similar to Silverhawk Peakers)

This alternative assumes that both of the Valmy units will operate on coal through December 31, 2025, as planned. This alternative does not include any significant investment in capital for the remaining life of the units. The units can be expected to continue operating as needed to support the transmission grid in addition to providing energy until their retirement. Upon retirement of both units on December 31, 2025, both Sierra and IPCo retire their interests in the existing units. The units would be replaced with a two-unit peaking plant similar to the proposed Silverhawk Peaking Plant that would be commercially operational by December 31, 2025. The combustion turbine units would be capable of operation on hydrogen if it is available at the plant in the future.

4.3 Option 2- Retire coal capability on both Valmy Units by 12/31/2025 and convert both of the units to run on natural gas only (with SCRs) through 12/31/2049 with Sierra continuing its 50% participation in both units.

This alternative assumes that both units will operate on coal through the summer 2025, then each unit would be converted to operate on natural gas with coal burning capability being retired at the plant by December 31, 2025. This alternative would include major investments in the existing plant (continuing operations capital), as well as a gas pipeline to be commercially available before December 31, 2025. The list of capital investments included in this option is included in Appendix D. The units can be expected to continue operating to support the transmission grid as necessary in addition to providing energy until their retirement on December 31, 2049.

4.4 Option 3- Retire coal capability on both Valmy Units by 12/31/2025 and convert both of the units to run on natural gas only (with SCRs) through 12/31/2049 with IPCo no longer participating and Sierra taking over 100% of both units.

This alternative assumes that both units will operate on coal through the summer 2025, then each unit would be converted to operate on natural gas with coal burning capability being retired at the plant by December 31, 2025. This alternative would include major investments in the existing plant (continuing operations capital), as well as a gas pipeline to be commercially available before December 31, 2025. The list of capital investments included in this option is included in Appendix D. Under this Option, Sierra would pay 100% of the costs of conversion and future operations and would receive 100% of the capacity from the units. The units can be expected to continue operating to support the transmission grid as necessary in addition to providing energy until their retirement on December 31, 2049.

4.5 Option 4- Retire coal capability on both Valmy Units by 12/31/2025 and replace with Solar/Battery Storage.

This alternative assumes that both of the Valmy units will operate on coal through December 31, 2025, as planned. This alternative does not include any significant investment in capital for the remaining life of the units. The units can be expected to continue operating as needed to support the transmission grid in addition to providing energy until their retirement. Upon retirement of both units on December 31, 2025, both Sierra and IPCo retire their interests in the existing units. The units would be replaced with a solar plant with Battery Energy Storage System ("BESS")

5.0 PLANNING ASSUMPTIONS

The following Planning Assumptions are used in the PROMOD analysis and are used in Sierra's business planning.

5.1 Must Run Requirements

Historically, transmission operations required that either Newmont's TS Power Plant ("TSPP") or Valmy be operational to maintain system stability. Actual events and simulations have shown inadequate MW resources (active power) resulting in unacceptable voltage levels and the potential for cascading outages under certain 345 kV and 120 kV line contingencies when no units are on-line in the Carlin Load Trend area. However, going forward because TSPP is not owned or operated by NV Energy, its output cannot be depended on to prevent cascading or for maintaining system voltage after January 2022. There will be no mechanism for the transmission operator to dispatch TSPP to maintain transmission reliability. Additionally, Newmont will likely only run their TSPP during periods of economic benefit, or when transmission capacity is scarce and lower cost energy cannot be delivered to the Newmont mining load.

NV Energy's Transmission Operations currently recommends placing the Valmy 1 **or** Valmy 2 into a Reliability Must-Run ("RMR") status starting November 1, 2022, until an active power replacement resource is in service at or near the same location. The recommendation is contingent on TSPP remaining online.

5.2 Labor

In the 2018 Valmy LSAP it was assumed that the Valmy units would operate on a seasonal basis with extended reserve shutdowns over the off-peak periods. With the changes to system support requirements for the units, the seasonal shutdowns did not materialize, and the units saw year-round operation. The plan for labor under the seasonal operations scenario was to allow for attrition and replace with contracted personnel that would support the plant during the summer peak period operation. The contracted personnel would only support the plant during plant operations and would

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all of the proposed capacitor banks proposed for the Carlin Trend area, the Carlin UVLS scheme will need to be re-studied to ensure that the current setpoint are still valid.

Following the completion of Greenlink North, the above P6 limitation would no longer be a valid concern.

Conclusion

Based on this assessment, it is clear that retirement of the Valmy plant and possible non-availability of the Newmont plant would result in several negative effects on Sierra's system.

a) Lack of generation internal to Sierra's system required to support the system for P1 events of various 345 kV lines

b) Increased challenges in performing transmission and generation maintenance.

c) Increased resource challenges specific to Tracy area load growth.

d) Lack of reactive support to maintain acceptable voltage levels in Northeastern Nevada

While reactive support in the form of capacitor banks is required to support voltages in the Carlin Trend area for certain contingencies, this study identifies the need for additional generation resources in Sierra's system in order to support contracted load growth until additional transmission (Greenlink West) can be built.

Several scenarios were studied in this analysis to ensure all combinations of both Valmy's and TSPP's retirements were addressed under single and multiple contingencies. With the system stressed to the full contracted load amounts, the surrounding interties into Sierra's system are not strong enough to support high import values without additional generation being able to respond to a loss of a major 345 kV line. These studies also assume that there are no existing outages in the system and all existing generaton is available to dispatch. Outages to existing transmission or generation assets make it even more difficult to operate the system and plan for additional contingencies without shedding load.

With adequate generation support and additional transmission to offset significant load growth, the transmission system can withstand the retirement of Valmy. Until Greenlink West is complete or additional generation is added to Sierra's system, Valmy generation should not be retired.

References

[1]. Standard TPL-001-5.1 — Transmission System Planning Performance Requirements, NERC, 7/1/2023.

[2]. "Glossary of Terms Used in NERC Reliability Standards", 2017, NERC, Updated April 4, 2017.

[3]. PUBLIC UTILITIES COMMISSION OF NEVADA, Application of Sierra Pacific Power Company d/b/a NV Energy for approval of its 2017-2036 Triennial Integrated Resource Plan and 2017-2019 Energy Supply Plan, Docket No. 16-07001, March, 2017.

[4]. "Reliability Criteria for Transmission System Planning", Rev 17, NV Energy, February 21, 2013.

[5]. "3345 – Consecutive Loss of Falcon – Robinson Summit and Humboldt - Midpoint", Rev 3.2, NV Energy, August 7, 2019.

[6]. "Procedure RC9310: Northern Nevada (NNEV) N-1-1 Mitigation Procedure", Rev 1.6, NV Energy, 07/28/2022

3. Detailed Contingency Analysis and Plots

3.1 CASE 5 Greenlink West

1. Case 5: Contingency analysis shows low voltages for various local load pockets for loss of the Fort Churchill 120/60 kV transformer or loss of the Millers 120 kV bus similar to what was identified in Case 1 (refer to Appendix A). These are all pre-existing local issues that do not have a bearing on this study.
   a. With the addition of Greenlink West, an additional source is added to the Reno load pocket and the TRI Center area. For the P1_L_3431 + P1_L_3422 contingency, the load shedding that was required in previous cases are no longer required. There were no reported violations for this contingency.
   b. For the P1_L_3428 + P1_L_3419 contingency, the voltage and frequency collapse previously seen in prior cases is no longer valid. With Newmont generation offline, 2 – 27 MVAR capacitor banks may be required at the Falcon 120 kV bus to support the voltage for loss of both lines.
   c. For a P6 event involving one segment of the Greenlink West 500 kV line, followed by the loss of either the #3419 or #3428 line, some system adjustments are required between contingencies. Loss of one of the Greenlink West 500 kV line segments would bring the system back to its current state. A reduction of the system import back to its existing value of 1275 MW is required to support the loss of the next major line (#3419 or #3428).
2. Case 5-1: Contingency analysis for Case 5-1 shows similar results to that seen in Case 5. At the maximum import limit, no additional voltage or overload violations are reported.

Key Decision Report

System Reliability – Valmy Reliability Must-Run

Description: The reliable operation of the transmission system in the Carlin Load Trend is based on a combination of generating and transmission equipment to control and maintain system stability. This Key Decision Report ("KDR") provides direction for the appropriate system configuration of resources in the Carlin Load Trend to manage risks associated with an undervoltage load shed condition impacting the Carlin Load Trend area while balancing fuel/coal supply risks for Valmy.

Owner: **Kim Whetzel – Dir., Grid Operations & Reliability**
Stakeholders: **Generation, Resource Optimization, Regulatory, Transmission, Transmission Planning**

Date: July 11, 2023

<u>Description of Key Decision:</u> Transmission operations require a reliable system over a broad spectrum of multiple layers of unplanned and feasible contingencies. Therefore, a minimum combination of local generation units and transmission elements need to be in service to maintain system stability in the Carlin Trend area. Both historical events and simulations have shown unacceptable voltage levels and the potential for cascading outages under certain transmission line contingencies with no local generation online. The key decision is to establish reliability must-run conditions for Valmy Unit 1 and Valmy Unit 2 based on system configurations. This recommendation balances fuel supply risk, system stability, and reliability with the cost of extending operations and emissions.

<u>Recommendations:</u> This KDR recommends placing the Valmy 1 **<u>or</u>** Valmy 2 into a Reliability Must-Run (RMR) status starting November 1, 2022, until an active power replacement resource is in service at or near the same location. The recommendation is contingent on Newmont's TS Power Plant (TSPP) remaining online.

Under this recommendation, when TSPP is in outage then Valmy 1 **<u>and</u>** Valmy 2 need to be in RMR status. Additionally, when any of the 345 kV or critical 120 kV lines are out of service for maintenance (or sustained forced outage) in the Carlin Trend, at least two of the following conditions must be met: Valmy 1 online, Valmy 2 online, TSPP online.

The recommendation would no longer be required once there is a set of local energy supply resources near Valmy and they are fully operational and reliable.

<u>Background:</u> The 522 MW North Valmy Generating Station ("Valmy") consists of two separate coal fired generation units connected to the 345 kV bus at Valmy substation. The generation plant is jointly owned by Sierra Pacific Power Company d/b/a NV Energy ("Sierra" or "NV Energy") and Idaho Power Company ("Idaho Power"). Idaho Power owns 50 percent of the output and associated transmission rights exporting north from Valmy to Idaho Power's system. NV Energy

Summary of Modeling

In 2018, NV Energy's Transmission Planning Department provided the completed LSAP to the Public Utility Commission (PUCN). The LSAP evaluated the transmission and generation investments that would be needed to retire the Valmy units by 2025. The analysis considered a scenario where no thermal generation or reactive capable generator was in operation in the Carlin Load Trend. The results, based on the TPL-001-4 P6 standard, indicated the current transmission system could not maintain reactive voltage in the Carlin Trend and that the approximate 360 MW of mining load would be at risk of a cascading voltage collapse with the loss of any 345 kV line connecting the area to import sources. To address the reliability concern, Transmission Planning recommended many options that NV Energy should deploy before the 2025 retirement date. Almost none of the transmission solutions and only a portion of the renewable energy projects have been put into the plans for implementation.

Transmission Planning's 2018 LSAP model was refreshed based on the current system design and evaluated based on a real time loss of reactive voltage support in the Carlin Load Trend (i.e., no Newmont, no Valmy 1 and Valmy 2 operational, but a Valmy 2 trip occurs and Valmy 1 has yet to start up). The analysis concluded there would be around 300 MW of load loss in the Carlin Trend area. The loss of load would be triggered by the under-voltage load shed (UVLS) remedial action scheme.

Operating Plan

Transmission Operations is governed by NERC TOP-001-5. Transmission Operators (TO) develop operating plans to comply with this standard. The RC0610 System Operating Limit Methodology guides the TO on how to determine System Operating Limits (SOL) and the TO determines what resources they will need in place to implement the plan. There may be multiple steps to a plan and the plan must cover the entire operating plan period for expected system conditions. Transmission operations applies an N-1-1 study plan to ensure adequate resources for the Carlin Trend. This is required because some sequences of unplanned forced outages can result in contingencies that require reduction to the TSPP generation source for mitigation. Then Transmission operations assesses the next possible contingency after the TSPP adjustment has been made. Post-contingency overloads and voltages are calculated in the Real-Time Contingency Analysis (RTCA) tool. In this case the Carlin Trend transmission operating studies require the addition of an active power (MW) resource to replace the reduced capacity of the TSPP and to push back on the overloaded lines and mitigate contingencies.

Historically and before adding the Bell Creek capacitor bank, NV Energy Transmission Operations needed two of the three steam-powered generation units in the Carlin trend to support load, voltage, and maintenance. This does not conflict with the planning analysis but from an operational perspective, the second unit is needed to mitigate some contingencies separately and to back up the first unit required by must-run. There are warm and cold startup delays associated with steam units. Valmy 1 or Valmy 2 can be chosen as the baseload unit in service which would be dispatched at minimum load (90 MW). When Humboldt-Rogerson 3419 line and Falcon-Robinson 3428 line are in service, NV Energy can remove Valmy 1 from the dispatch if TSPP is available. The Bell Creek caps maintain the voltage during an N-1-1 scenario but do not alleviate the overloads.

Scheduled maintenance outages of TSPP, Valmy 1 or Valmy 2 will only be allowable from September 15 through May 15. The system load will be too great between May 15 and September

ATTACHMENT RA-6

NV Energy Response to Sierra Club Data Request 3-06 in Docket No. 23-08015

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	23-08015	**REQUEST DATE:**	10-31-2023
REQUEST NO:	SC 3-06	**KEYWORD:**	valmy tracy operational changes comply environmental policy analysis
REQUESTER:	Woolsey	**RESPONDER:**	Johns, Mathew

REQUEST:

Reference: Valmy and Tracy

Question: Please provide all analyses that the Company has performed within the last three years regarding potential operational changes (not capital investments) at Valmy and Tracy that may help comply with final, proposed, or possible future environmental regulations including, but not limited to: regional haze rules and the federal Good Neighbor Plan for the 2015 ozone National Ambient Air Quality Standards (NAAQS). If the Company has not performed analysis of the potential to comply with environmental policy through operational changes instead of capital investments at these units, please explain why not.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

Please refer to the response Sierra Club Data Request 1-18, and the detailed discussion of these regulation and impacts to Valmy or Tracy 4/5 prepared as part of the Supply Plan – Generation.

As discussed in the Supply Plan – Generation narrative, technically feasible emission controls are being re-assessed as part of the Regional Haze Rule for both Valmy Units 1 and 2 and Tracy 4/5 in lieu of federally enforceable retirement dates of 2028 and 2031, respectively.

Under the federal Good Neighbor plan, if it becomes effective following the current stay in Nevada, Valmy Units 1 and 2 will be allocated fewer NOx allowances in 2026 based on a lower NOx emission rate and further reduction of NOx allowances in 2027 to a level commensurate with SCR controls. Without NOx emission controls, operation of Valmy Units 1 and 2 will become limited during the 2026 ozone season (May – September) and further constrained starting in 2027 to levels that would not be able to meet operational conditions, such as reliability must-run requirements required one or both units to be available.

For these reasons, operational changes alone would not meet the requirements identified in the filing as well as the regulations.

ATTACHMENT RA-7

NV Energy Confidential Workpaper “2024 IRP – F&PP Figures” (excerpt)

This file is marked confidential and will be made available for those parties who have signed the protective agreement.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the **PUBLIC AND REDACTED DIRECT TESTIMONY OF ROSE ANDERSON ON BEHALF OF SIERRA CLUB** in Docket No. 24-05041 by electronic mail to the following:

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By: *__/s/ Maddie Lipscomb______________*