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 First Amendment to the 2021 Joint Integrated Resource Plan.	Docket No. 22-03___

VOLUME 2 OF 4

TESTIMONY

DESCRIPTION **PAGE NUMBER**

DAVID HARRISON, JR.

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

First Amendment to the
2021 Joint Triennial Integrated Resource Plan (2022-2041)
Docket No. 22-03___

Prepared Direct Testimony of

David Harrison, Jr.

I. INTRODUCTION

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

A. My name is David Harrison, Jr. I am an economist and Managing Director at NERA Economic Consulting ("NERA"), an international firm of economists. Established in 1961, NERA has earned wide recognition for its work in energy, environmental economics and regulation, antitrust, public utilities regulation, transportation, health care, international trade and other topics. The work is performed by more than 500 professional staff members qualified in economics, statistics, mathematics, computer applications, and business administration. NERA operates in numerous offices across North America, Europe, and the Pacific Rim. My business address is 99 High Street, Boston, Massachusetts. I am filing testimony on behalf of Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and together with Nevada Power, the "Companies" or "NV Energy").

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

A. I received a Ph.D. in Economics from Harvard University, where I was a Graduate Prize Fellow. I also hold a B.A. magna cum laude in Economics from Harvard College, where I was a member of Phi Beta Kappa, and a M.Sc. in Economics from the London School of Economics, where I was the Rees Jeffreys Scholar.

Before joining NERA, I was an Associate Professor at the John F. Kennedy School of Government at Harvard University, where I taught economics, energy and environmental policy, benefit-cost analysis, and other subjects. I was a member of the Faculty Steering Committee of the Energy and Environmental Policy Center at Harvard University, and a member of the Advisory Board of the Interdisciplinary Program in Health at the Harvard School of Public Health.

I earlier served as a Senior Staff Economist on the President's Council of Economic Advisors, where my areas of responsibility included energy and environment, natural resources, occupational health and safety, and transportation. I also have worked at the U.S. Department of Transportation, the U.S. Department of Housing and Urban Development, and the National Bureau of Economic Research. My full curriculum vita is provided in **Exhibit Harrison-Direct-1**. I received a Ph.D. in Economics from Harvard University, where I was a Graduate Prize Fellow. I also hold a B.A. magna cum laude in Economics from Harvard College, where I was a member of Phi Beta Kappa, and a M.Sc. in Economics from the London School of Economics, where I was the Rees Jeffreys Scholar.

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II. TESTIMONY OBJECTIVES

3. Q. WHAT ARE THE PURPOSES OF YOUR TESTIMONY?

A. I have been asked by the Companies to offer my expert opinion in six areas related to the environmental costs and economic impacts of the two resource cases—which are referred to as the Preferred Plan and the Alternate Plan—that are included in the First Amendment to the 2021 Joint Integrated Resource Plan ("Amendment"): (1) future national regulation of carbon dioxide ("CO_2") emissions from power plants, including the possibility of a "price" that would be placed on the Companies' CO_2 emissions, as well as the implications of CO_2 regulations on the prices of fuels used by the Companies; (2) external environmental costs for air emissions, including damage-based monetary values for conventional and toxic emissions; (3) external environmental costs based on monetary estimates of the social cost of carbon ("SCC") for CO_2 emissions as required by the August 2018 Order of the Commission in Docket No. 17-07020 to implement Senate Bill 65 (2017) ("August 2018 Order"); (4) external monetary costs of the Companies' water consumption, based upon water use that is not included in the Present Worth Revenue Requirement ("PWRR") for the cases; (5) qualitative assessments of the potential external environmental costs for land use as well as other potential environmental costs not included in the above categories; and (6) the net economic benefits (i.e., economic impacts) to the Nevada economy. I also provide a summary of conclusions regarding the analyses, including information on the implications of my environmental cost estimates for the Present Worth of Social Costs ("PWSC"), which are equal to the sum of PWRR and environmental costs that are not internalized as private costs to the Companies. The results of my analyses are discussed in detail in a report I prepared in collaboration with NERA colleagues ("NERA Report"), which is provided in Technical Appendix Item ECON-9.

4. Q. PLEASE INDICATE HOW YOUR TESTIMONY RELATES TO THE REQUIREMENTS FOR INTEGRATED RESOURCE PLAN SUBMISSIONS.

A. My testimony relates to two major categories of requirements for integrated resource plans ("IRPs"), one related to assessing environmental costs and one related to assessing the "net economic benefits" of alternative cases. The Nevada Administrative Code ("NAC") requires Nevada electric utilities to rank their cases on the basis of the PWRR and the PWSC. As noted, the PWSC of an IRP case is defined as the sum of the PWRR plus "environmental costs that are not internalized as private costs to the utility."[1] Environmental costs are defined by the Commission

[1] NAC § 704.937

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as "costs, wherever they may occur, that result from harm or risks of harm to the environment after the application of all mitigation measures required by existing environmental regulation or otherwise included in the resource plan."[2] The environmental costs "must be quantified for air emissions, water and land use."[3]

Section 704.9357 of the NAC requires the Companies to assess the "net economic benefits" of resource plans reflecting "both the positive and negative changes." Section 704.9357 of the NAC specifies that benefits to be calculated include in-state expenditures related to capital, supplies, wages, fees, and taxes associated with the resource plans. Greater expenditures would produce positive economic impacts. The regulation does not include any specific language on how to assess the potential negative impacts of higher electricity rates.

5. Q. PLEASE PROVIDE AN OVERVIEW OF THE ALTERNATIVE CASES AND THE MAJOR ELEMENTS THAT DIFFERENTIATE THEM?

A. This Amendment includes two resource cases for meeting electricity demand and state renewable energy requirements over the next 30 years (from 2022 to 2051) as well as a Base Case used in the economic impact analysis. Each case meets or exceeds the current Renewable Portfolio Standard ("RPS") in every year, meets the new 16 percent planning reserve margin ("PRM") for each utility and includes most of the same generation and transmission resources.

The following are the names and brief summaries for the two cases in the Amendment as well as a Base Case used in the economic impact assessments.

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[2] NAC § 704.9359
[3] *Id.*

- **Base Case**. This case matches the final approval and directives from the 2021 Joint IRP and adds: wet compression projects on the Clark peaker units; wet compression projects on Harry Allen units 3 and 4; and power augmentation on Clark Mountain units 3 and 4 at Tracy Station.
- **Preferred Plan.** This case includes all the projects included in the Base Case and adds: other turbine upgrades; a power purchase agreement ("PPA") contract for 25 megawatts ("MW") from a new geothermal project; and a 220 MW, two-hour grid-tied battery energy storage system ("BESS").
- **Alternate Plan.** This case includes all the projects included in the Base Case and adds: other turbine upgrades; a PPA contract for 25 MW from a new geothermal project; and a new peaker project at Silverhawk.

The NERA Report provides additional information on the specific generation units and transmission lines included in the Base Case and the two Amendment cases.

III. CARBON DIOXIDE PRICE SCENARIO

6. Q. PLEASE SUMMARIZE THE CARBON DIOXIDE PRICE SCENARIOS YOU HAVE DEVELOPED.

A. I developed several CO_2 price scenarios to reflect uncertainty regarding the potential future national regulation of CO_2 emissions from existing power plants under the Clean Air Act and the extent to which implementation of these regulations might impose a "price" on CO_2 emissions from power plants. One of the scenarios assumes that implementation would not lead to a CO_2 price, and three of the scenarios assume implementation would lead to a CO_2 price through a national cap-and-trade program for utility emissions. The three national CO_2 cap-and-trade scenarios for electric sector emissions are assumed to begin in 2027, with caps consistent with allowance prices that begin at $15 per metric ton ("Low CO_2 Price

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scenario"), \$25 per metric ton ("Mid CO_2 Price scenario"), and \$35 per metric ton ("High CO_2 Price scenario"). A cap-and-trade program has various well-recognized advantages over a regulatory approach that would mandate specific control technologies, including greater incentives to minimize the overall cost of achieving carbon emission reductions.

7. Q. WHICH CARBON DIOXIDE PRICE SCENARIO DID YOU USE FOR PURPOSES OF THIS SUBMISSION?

A. I used the Mid CO_2 Price scenario for the analyses in this submission. Thus, all of the results developed here assume that regulation of electric utility emissions would lead to a national cap-and-trade program that would begin in 2027 and result in allowance prices that start at \$25 per metric ton in 2027 and increase over time at a 5 percent real rate of interest. The NERA Report provides additional information on this scenario.

8. Q. HOW DID YOU DEVELOP ESTIMATES OF THE EFFECTS OF THE CARBON DIOXIDE SCENARIOS ON THE PRICES THAT THE COMPANIES WOULD PAY FOR FUELS?

A. I used the N_{ew}ERA model, a model developed and maintained by NERA that includes a detailed electric sector model and related integrated fuel price and macroeconomic models, as explained in the NERA Report. The electric sector model (the primary model used for my analysis) is a detailed model of the electric and coal sectors. Each of the more than 17,000 electric generating units in the United States is represented in the model. The model minimizes costs while meeting all specified constraints, such as demand, peak demand, emissions limits, and transmission limits. The model is similar to the National Energy Modeling

System ("NEMS"), developed and maintained by the U.S. Energy Information Administration ("EIA") in the U.S. Department of Energy.

I used N$_{ew}$ERA to estimate the effects of the carbon dioxide allowance prices over time on fuel prices under the Mid CO_2 Price scenario. As requested by the Companies, I estimated changes in prices for Henry Hub natural gas and Rocky Mountain coal (Utah) and subbituminous coal (Southern Wyoming) and transmitted these price impacts to the Companies for use in their PROMOD runs. The NERA Report provides additional information on the estimation of these fuel price effects.

9. Q. PLEASE EXPLAIN HOW THE CARBON DIOXIDE SCENARIO AFFECTS NV ENERGY'S MODELING OF ITS ALTERNATIVE CASES AND ITS FINANCIAL PLAN.

A. The allowance prices under the Mid CO_2 Price scenario and the associated fuel price changes have been incorporated into the Companies' PROMOD runs and financial planning model. The prices of CO_2 emissions under the Mid CO_2 Price scenario are included in the costs to dispatch fossil-fuel generating units and thus affect the generation of various units under the different cases. In turn, I use the Companies' PROMOD projections along with other information to develop estimates of the environmental costs of the cases, including environmental costs related to conventional and toxic air emissions as well as environmental costs related to CO_2 emissions.

I also developed estimates of the value of free allowances that the Companies could receive under the potential cap-and-trade program modeled in the Mid CO_2 Price scenario in the NERA Report. The value of these free allowances reduces the net costs incurred by the Companies to comply with regulatory requirements. The net financial impact in a given year for the emissions from the Companies' generation depends on the level of emissions, the allowance price, and the number of emission allowances the Companies would receive for free under the assumed cap-and-trade program. The NERA Report provides information on the methods I used to estimate the numbers of free allowances received by the Companies over time. I understand that the potential allowance allocations are incorporated into the Companies' financial planning model.

IV. ENVIRONMENTAL COSTS FOR CONVENTIONAL AND TOXIC AIR EMISSIONS

10. Q. PLEASE SUMMARIZE THE METHODS YOU USED TO ESTIMATE ENVIRONMENTAL COSTS FOR CONVENTIONAL AND TOXIC AIR EMISSIONS.

A. I applied a "damage-function" framework to evaluate the environmental costs of air emissions for which sufficient data were available to estimate the potential damages related to health effects. The specific emissions in this category include nitrogen oxides ("NO_x"), volatile organic compounds ("VOC"), particulate matter ("PM"), mercury ("Hg"), and sulfur dioxide ("SO_2"). The national SO_2 cap set in the Acid Rain Trading Program is not expected to be binding—with allowance prices expected to be zero or close to zero—and, thus, SO_2 emissions are evaluated based on damage values rather than as covered by a binding cap-and-trade program as was appropriate in some earlier IRP analyses. The damage-function approach is a standard economic approach for assessing the environmental costs of air emissions when emissions are not capped. The damage values that I used for these emissions are primarily based on health effects associated with ambient PM (which depend on NO_x emissions and SO_2 emissions that operate as precursors for PM as well as emitted PM) and ground-level ozone (which is formed by NO_x and VOC emissions), as described in the NERA Report. To develop this information, I relied on data and methodologies recently developed and used by the U.S. Environmental Protection Agency ("EPA") as well as other information. I also estimated damage values for mercury from information developed by the EPA in its assessments of the final Mercury and Air Toxics Standards ("MATS") rule. As in prior assessments, I did not assess the validity of the EPA information used in these calculations.

11. Q. PLEASE SUMMARIZE OTHER SOURCES OF INFORMATION YOU USED TO DEVELOP THESE ENVIRONMENTAL COST ASSESSMENTS.

A. I relied on information provided by the Companies regarding the various resource cases. This information included emission rates for relevant facilities, forecasted annual generation and heat input for relevant facilities (based on the PROMOD dispatch modeling results), and other information as described in the NERA Report. The information provided by the Companies relates to both Nevada Power and Sierra, because the two systems were modeled jointly, and thus the joint plans involve emissions related to both the Nevada Power and Sierra systems. I supplemented the information from the Companies with relevant information from public sources; for example, as noted above, in estimating health effects and dollar values for various emissions, I relied on data and methodologies developed by the EPA.

12. Q. PLEASE SUMMARIZE YOUR ESTIMATES OF THE ENVIRONMENTAL COSTS OF CONVENTIONAL AND TOXIC AIR EMISSIONS.

A. **Table Harrison Direct-1** presents the estimated environmental costs related to conventional and toxic air emissions, including differences for the Alternate Plan relative to the environmental costs of the Preferred Plan. The tables include costs for emissions related to pollutants subject to the National Ambient Air Quality Standards ("NAAQS") and the MATS rule. Based on the NAAQS, I have included emissions of NO_x, VOC, PM, carbon monoxide ("CO"), and SO_2. Damage values for VOC emissions are zero because air quality modeling results indicate that, given ambient climatic conditions, changes in VOC emissions do not affect ozone concentrations in Nevada (which are driven at the margin by NO_x emissions). CO is not monetized because the required air quality modeling data are not available. Note that CO emissions estimates are provided in the NERA Report. Based on their inclusion in the MATS rule, emissions of mercury and hydrogen chloride ("HCl") are also included. HCl is not monetized because the EPA did not develop the relevant information in the MATS regulatory impact analysis; however, HCl emission projections are provided in the NERA Report. Note that the MATS rule uses PM emissions as a proxy for non-mercury metallic air toxics; however, since PM emissions are included based upon the NAAQS, this element of the MATS rule does not lead to estimates of additional environmental costs. The NERA Report provides additional information on the methods used to develop environmental costs for these pollutants. I do not expect that including costs for other pollutants, if they could be estimated, would have any significant effect on my estimates of the environmental costs of conventional and toxic air emissions.

Table Harrison Direct-1. Present Values of Environmental Costs for Conventional Air Emissions and Toxics, 2022-2051 (2022$ Millions)

	Preferred	Alternate	Difference (Alternate - Preferred)
NOx	$1.32	$1.33	$0.01
PM	$56.56	$57.16	$0.60
VOC	$0.00	$0.00	$0.00
CO	--	--	--
SO2	$2.33	$2.32	-$0.01
Mercury	$0.00	$0.00	$0.00
HCl	--	--	--
Total	**$60.21**	**$60.81**	**$0.60**

Notes: All values are present values as of 2022 in millions of 2022 dollars for the period 2022-2051 using nominal annual discount rates of 7.14 percent for Nevada Power and 6.75 percent for Sierra. Real annual discount rates were converted to nominal annual values using inflation rate information, as provided by the Companies.
Total may differ from the sum of the rows due to independent rounding.
"-" denotes that the environmental costs of the air emissions are not monetized. The costs of VOC emissions are zero because of evidence that these emissions do not contribute to urban ozone, the relevant damage category. The costs of mercury emissions round to zero when reported in millions, as present values are less than $1000 for both Amendment cases.
Source: NERA calculations as explained in text.

In addition to the potential health costs associated with conventional air emissions and toxics, there are also potential non-health costs. As noted in the NERA Report, non-health damages are expected to be small relative to the health damages, and thus I would not expect their omission to have a major effect on the environmental cost results, particularly the comparative results for the two cases.

13. Q. PLEASE COMMENT ON DIFFERENCES IN ENVIRONMENTAL COSTS RELATED TO CONVENTIONAL AND TOXIC AIR EMISSIONS FOR THE ALTERNATE PLAN RELATIVE TO THE PREFERRED PLAN.

A. These results indicate that the Alternate Plan has greater conventional and toxic air emissions costs than the Preferred Plan by about $600,000.

V. SOCIAL COSTS OF CARBON FOR CARBON DIOXIDE EMISSIONS

14. Q. PLEASE DESCRIBE THE METHODOLOGY YOU USED TO DEVELOP ESTIMATES OF THE SOCIAL COST OF CARBON FOR CARBON DIOXIDE EMISSIONS.

A. The August 2018 Order requires that environmental costs include estimates of the "social cost of carbon" and prescribes a methodology for their calculation. The regulations state that "environmental costs to the State associated with operating and maintaining a supply plan or demand-side plan must be quantified for air emissions, water and land use and the social cost of carbon as calculated pursuant to [NAC § 704.937(5)]."[4] The analyses I developed comply with these regulatory requirements.

I developed estimates of carbon dioxide emissions over time under the various cases using information from modeling done by the Companies and from other sources. The NERA Report provides information on the trajectories of carbon dioxide emissions for the two Amendment cases and on the differences in emissions trajectories between the Alternate Plan and the Preferred Plan.

[4] NAC § 704.9359.

Subsection 5 of the August 2018 Order requires that "the social cost of carbon must be determined by subtracting the costs associated with emissions of carbon internalized as private costs to the utility pursuant to subsection 3 from the net present value of the future global economic costs resulting from the emission of each additional metric ton of carbon dioxide. The net present value of the future global economic costs resulting from the emission of an additional ton of carbon dioxide must be calculated using the best available science and economics such as the analysis set forth in the 'Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis' released by the Interagency Working Group on Social Cost of Greenhouse Gases in August 2016."[5] As discussed in the NERA Report, I used the most recent estimates of the Interagency Working Group that were provided in February 2021.

The Interagency Working Group provides estimates of the present value of future global economic costs from an additional ton of carbon dioxide for three discount rates—2.5 percent, 3 percent, and 5 percent—using the average of the damages distribution it calculated from modeling results. It also provides a fourth set of global economic costs based on the 3 percent discount rate and the 95th percentile of the damages distribution, which it notes are designed "to represent the higher-than-expected economic impacts from temperature change further out in the tails of the [global economic cost] distribution" (Interagency Working Group 2021, p.

[5] There is some potential confusion in use of the term "social cost of carbon." The term is used by the Interagency Working Group, as well as many commentators, to refer to estimates of the present value of the future global economic cost of an additional ton of CO_2 emissions emitted in a given year. In contrast, the Commission in its August 2018 Order refers to the "social cost of carbon" as the *difference* between this present value and the costs internalized as private costs (in this case the allowance prices). NERA adopts the terminology of the August 2018 Order in its current report (although its previous reports have used "social cost of carbon" to refer to the values developed by the Interagency Working Group). The NERA Report provides information on the methodology used by the Interagency Working Group to develop its estimates and on the wide range of estimates that are provided in the February 2021 interim report, which updates the results from the August 2016 report for inflation.

10). These four sets of values cover a very large range and, indeed, the full range of values reported by the Interagency Working Group is much greater than these four sets of estimates.

I used the values of future allowance prices under the Mid CO_2 Price scenario as measures of the costs of CO_2 emissions that are internalized as private costs to the utility; this approach is consistent with the Companies' use of these prices in the PROMOD modeling. In compliance with the August 2018 Order, I calculated the social cost of carbon in each year as the Interagency Working Group February 2021 values minus the allowance price. I used the Interagency Working Group values for a 3 percent discount rate and the average of the damages distribution. The NERA Report provides costs of CO_2 emissions using the other Interagency Working Group sets of values.

15. Q. PLEASE SUMMARIZE YOUR ESTIMATES OF THE SOCIAL COSTS OF CARBON DIOXIDE EMISSIONS FOR THE FIVE RESOURCE CASES.

A. **Table Harrison Direct-2** shows the CO_2 costs (as present values) for the two Amendment resource cases using the 3 percent discount rate and average damage values for future global economic costs and the projected allowance prices under the Mid CO_2 Price scenario. Also included in the table is the difference between the Alternate Plan and the Preferred Plan. Results using the other three Interagency Working Group sets of values are provided in an Appendix to the NERA Report.

Table Harrison Direct-2. Present Values of Social Costs of Carbon, 2022-2051 (2022$ Millions)

Preferred	Alternate	Difference (Alternate - Preferred)
$5,291	$5,344	$53

Notes: All values are present values as of 2022 in millions of 2022 dollars for the period 2022-2051 based on the methodology outlined above.

Source: NERA calculations as explained in text.

16. Q. PLEASE COMMENT ON THE DIFFERENCES IN SOCIAL COSTS OF CARBON DIOXIDE EMISSIONS IN THESE CASES.

A. The social costs of carbon are greater for the Alternate Plan than for the Preferred Plan by about $53 million.

17. Q. PLEASE COMMENT ON THESE ESTIMATES OF THE SOCIAL COST OF CARBON AND THEIR RELATIONSHIP TO OTHER ENVIRONMENTAL COSTS.

A. I have in prior testimonies for IRPs noted that the global values developed by the Interagency Working Group are not comparable to the other environmental costs for several reasons: (a) the Interagency Working Group values are more uncertain partly because they are based upon impacts in the distant future; (b) the Interagency Working Group values are based on different discount rates than the discount rates used to calculate the present value of the other environmental costs; and (c) the Interagency Working Group values are based upon global damages rather than U.S. damages.

VI. ASSESSMENT OF EXTERNAL ENVIRONMENTAL COSTS OF WATER USE COSTS NOT INCLUDED IN THE PWRR

18. Q. PLEASE SUMMARIZE YOUR METHODOLOGY FOR ESTIMATING THE EXTERNAL ENVIRONMENTAL COST OF WATER USE.

A. I estimated the potential external environmental costs of water use based upon the value of water use that is not included in the PWRR using plant-specific information on water consumption and water ownership from the Companies. I developed proxies for existing and future Companies' plants based on historic information on agricultural, municipal, and groundwater values in Nevada. The additional costs of water are based upon water use from wells owned by the Companies and do not include water that is leased or purchased, since the value of leased or purchased water is presumed to be included in the PWRR. In addition, no additional water costs are calculated for power purchased by the Companies through contracts or spot market transactions because I assume that all water costs are included in the prices that the Companies pay, and thus, are included in the PWRR. Similarly, no additional water costs are calculated for any PPA because I assume that the costs of any water that is used by third-party electricity generators—whether these are actual costs to the generators or opportunity costs of using their own water supply—will be included in the product rate paid by the Companies, and thus, in the PWRR. The methodology and data I used are described in the NERA Report.

19. Q. PLEASE SUMMARIZE YOUR ESTIMATES OF THE EXTERNAL ENVIRONMENTAL COSTS OF WATER USE FOR THE TWO RESOURCE CASES.

A. **Table Harrison Direct-3** shows the estimated external environmental costs of water use (i.e., the added costs beyond those already included in the PWRR) for the two resource cases.

Table Harrison Direct-3. Present Values of External Environmental Water Costs, 2022-2051 (2022$ Millions)

Preferred	Alternate	Difference (Alternate - Preferred)
$10.7	$10.6	-$0.1

Notes: All values are present values as of 2022 in millions of 2022 dollars for the period 2022-2051 using nominal annual discount rates of 7.14 percent for Nevada Power and 6.75 percent for Sierra. Real annual values were converted to nominal annual values using inflation rate information, as provided by the Companies.
Source: NERA calculations as explained in text.

20. Q. PLEASE COMMENT ON DIFFERENCES IN WATER ENVIRONMENTAL COSTS AMONG THE CASES.

A. The Alternate Plan has smaller external water costs than the Preferred Plan by about $100,000 due to the Alternate Plan's somewhat smaller generation at facilities that use water from wells owned by the Companies.

VII. ASSESSMENT OF OTHER ENVIRONMENTAL COSTS

21. Q. DID YOU CONSIDER THE COSTS OF OTHER POTENTIAL ENVIRONMENTAL IMPACTS?

A. Yes, I also considered potential environmental costs related to land use, solid waste disposal and water quality in Nevada. I concluded that any cost differences were likely to be highly site-specific and not likely to be significant relative to the estimated environmental costs.

VIII. ASSESSMENT OF TOTAL ENVIRONMENTAL COSTS

22. Q. PLEASE SUMMARIZE YOUR ASSESSMENT OF THE TOTAL MONETIZED ENVIRONMENTAL COSTS OF THE ALTERNATIVE CASES.

A. **Table Harrison Direct-4** summarizes my estimates of the total monetized costs for the two resource cases and the differences for the Alternate Plan relative to the Preferred Plan, expressed as present values.

Table Harrison Direct-4. Present Values of Total Monetized Environmental Costs, 2022-2051 (2022$ Millions)

	Preferred	Alternate	Difference (Alternate- Preferred)
Conventional Air Emission Costs	$60.2	$60.8	$0.6
Additional Water Costs	$10.7	$10.6	-$0.1
Social Costs of Carbon	$5,291.4	$5,344.1	$52.7
Total Environmental Cost	$5,362.3	$5,415.5	$53.2

Notes: All values are present values as of 2022 in millions of 2022 dollars for the period 2022-2051. For conventional air emissions and water cost present values are calculated using nominal annual discount rates of 7.14 percent for Nevada Power and 6.75 percent for Sierra. The social cost of carbon values are based upon a 3 percent annual discount rate used to calculate global environmental costs.
Source: NERA calculations as explained in text.

23. Q. PLEASE COMMENT ON THE DIFFERENCES IN TOTAL MONETIZED ENVIONMENTAL COSTS AMONG THE CASES.

A. These results indicate that the total monetized environmental costs are lower for the Preferred Plan than for the Alternate Plan by about $53.2 million, with the difference due primarily to the lower social cost of carbon for the Preferred Plan than for the Alternate Plan.

24. Q. PLEASE SUMMARIZE YOUR CONCLUSIONS ON THE NON-MONETIZED COSTS OF THE TWO AMENDMENT CASES

A. I concluded that any differences in environmental costs related to land use, solid waste and water quality between the two Amendment cases were not likely to be significant relative to the estimated environmental costs.

IX. ECONOMIC IMPACTS

25. Q. PLEASE SUMMARIZE THE CURRENT REGULATIONS RELATED TO EVALUATING THE ECONOMIC IMPACTS OF INTEGRATED RESOURCE PLANS IN NEVADA.

A. Section 704.9357 of the NAC requires the Companies to assess the "net economic benefits" of resource plans reflecting "both the positive and negative changes." Section 704.9357 of the NAC specifies that benefits to be calculated include in-state expenditures related to capital, supplies, wages, fees, and taxes associated with the resource plans. Greater expenditures would lead to positive economic impacts. The regulation does not include any specific language on how to assess the negative economic impacts of higher electricity prices.

26. Q. WHAT MODEL DID YOU USE TO ESTIMATE ECONOMIC IMPACTS FOR THIS ANALYSIS?

A. My analysis uses the REMI model to provide comprehensive estimates of economic impacts for the alternative resource plans, including the positive effects of expenditures in Nevada as well as the potential negative effects of greater electricity rates under more expensive plans. I note in particular the choice of REMI over IMPLAN because REMI is capable of modeling all potential negative effects of higher electricity rates while IMPLAN is not. The NERA Report provides more detail on the distinctions between these two models.

27. Q. PLEASE SUMMARIZE THE SOURCES OF INFORMATION YOU USED TO ASSESS THE ECONOMIC IMPACTS OF THE RESOURCE PLANS.

A. I relied on several sources of information as discussed in the NERA Report, including information provided by the Companies, as well as data from the U.S. EIA. As described in the NERA Report, the Companies provided information on construction costs, fuel costs and annual operating and maintenance costs for the two Amendment cases and for one additional case that we assume to be consistent with the REMI baseline ("Base Case") as well as information on the electricity revenue that would be collected from residential, commercial and industrial customers under the two Amendment cases and the Base Case. I used detailed cost data from EIA for renewable projects to assess the economic impacts in Nevada of the Companies' renewable PPAs. I also used information from the U.S. government on the expenditure profiles of other types of electricity generation units to develop specific inputs for the REMI modeling. Note that my analysis is based primarily upon the costs and revenue requirements related to the Companies' bundled customers and does not include effects related to its customers who only purchase transmission services ("transmission-only" customers), as the PWRR cost information is based on bundled customers. The only exception is that the costs and revenue requirements include those related to provision of 90 MW of additional reserve capacity for transmission-only customers, which are also included in the PWRR.

I used the above information to develop inputs for the REMI modeling. The REMI inputs include estimates of the direct expenditures in the two Amendment cases, including construction, fuel and annual operating and maintenance expenditures, as well as estimates of electricity revenue requirements for various customer classes under the cases. As noted below, these inputs are calculated relative to the Base Case for input to the REMI model.

28. Q. PLEASE SUMMARIZE THE BASELINE OR REFERENCE SCENARIO YOU USED AND THE MEASURES YOU USED TO DETERMINE ECONOMIC IMPACTS.

A. REMI modeling includes a reference or "baseline" forecast. The Base Case developed by NV Energy is assumed to be consistent with the REMI baseline forecast. Because the Base Case is presumed to be included in the REMI baseline, the inputs to the REMI model are not the absolute values for expenditures and revenue requirements under the two cases but rather the *differences* between expenditures and revenue requirements for each of the two Amendment cases relative those in the Base Case.

I first develop the REMI model results, which provide estimates of the growth of the Nevada economy under the various cases. Then I develop tables that compare the *differences* in REMI model results among the cases. As with the environmental costs, I calculate the differences between the Alternate Plan and the Preferred Plan to compare the impacts of the two Amendment cases. Note that using the Preferred Plan to compare REMI model *results* for the Alternate Plan is not inconsistent with using the Base Case as the reference scenario for the purpose of developing the REMI model *inputs*.

I characterize the Nevada "economic impacts" in four impact categories: (1) gross state product, (2) personal income, (3) state and local tax revenue, and (4) employment. As discussed in the NERA Report, state and local tax revenue is calculated by NERA based on Federal Tax Administration assumptions, and the other three impact categories come directly from the REMI model.

29. Q. PLEASE SUMMARIZE THE EXPENDITURES INFORMATION USED AS INPUTS TO YOUR ECONOMIC IMPACTS ANALYSIS.

A. Table Harrison Direct-5 shows the average annual expenditures in Nevada under the three cases, including the two Amendment cases and the Base Case. The table includes construction expenditure, fuel expenditures, and non-fuel operating and maintenance ("O&M") expenditures. Only expenditures that occur in Nevada are included in these calculations because of the focus on estimating the economic impacts in Nevada. As discussed in the NERA Report, these values exclude certain categories of expenditures, such as market purchases, because those expenditures are assumed to flow to power producers outside Nevada (and thus not generate positive economic impacts in Nevada).

Table Harrison Direct-5. Average Annual Total Expenditures, 2022-2051 (2022$ Millions)

	Base	Preferred	Alternate
Construction	$1,476	$1,481	$1,479
Fuel	$349	$343	$347
O&M	$372	$377	$379
Total	**$2,197**	**$2,201**	**$2,205**

Notes: All values are average annual values over the period from 2022 to 2051 in millions of 2022 dollars. Dollar year conversions are based on inflation rate information, as provided by the Companies.
Source: NERA calculations as explained in text.

Table Harrison Direct-6 shows the differences in average annual expenditures for the economic impact analysis over the period from 2022 to 2051 for the two Amendment cases relative to the Base Case (which as noted is the case assumed to be consistent with REMI's reference case). The table also shows the differences between the Alternate Plan and the Preferred Plan. Note that these average annual values over the 30-year period do not reflect differences in timing of expenditures over the 30-year period, although these differences in timing are included in the REMI modeling.

Table Harrison Direct-6. Average Annual Total Expenditures, Relative to the Base Case, 2022-2051 (2022$ Millions)

	Base	Preferred	Alternate	Difference (Alternate - Preferred)
Construction	-	$5	$3	-$2
Fuel	-	-$6	-$2	$4
O&M	-	$5	$7	$2
Total	**-**	**$4**	**$8**	**$4**

Notes: All values are average annual values over the period from 2022 to 2051 in millions of 2022 dollars. Dollar year conversions are based on inflation rate information, as provided by the Companies.
Source: NERA calculations as explained in text.

30. Q. PLEASE SUMMARIZE THE REVENUE REQUIREMENTS INFORMATION USED AS INPUTS TO YOUR ECONOMIC IMPACTS ANALYSIS.

A. **Table Harrison Direct-7** shows the average annual electricity revenue requirements for 2022-2051, apportioned by customer class (based on the methodology described in the NERA Report that combines information of Nevada Power and Sierra).

Table Harrison Direct-7. Average Annual Electricity Revenue by Customer Class, 2022-2051 (2022$ Millions)

	Base	Preferred	Alternate
Residential	$1,082	$1,085	$1,087
Commercial	$532	$534	$534
Industrial	$242	$243	$243
Total	**$1,856**	**$1,863**	**$1,865**

Notes: All values are average annual values over the period from 2022 to 2051 in millions of 2022 dollars. Dollar year conversions are based on inflation rate information, as provided by the Companies.
Source: NERA calculations as explained in text.

Table Harrison Direct-8 shows the differences in average annual values of electricity revenue for each of the two Amendment cases relative to the Base Case, as well as the differences between the Alternate Plan and the Preferred Plan. The differences relative to the Base Case in each year are the values that are included in the REMI modeling, based on detailed information that reflects the direct impacts on the three sets of customers. As with the expenditures, these average values do not reflect differences in timing, although timing differences are included in the REMI modeling.

Table Harrison Direct-8. Average Annual Electricity Revenue by Customer Class, Relative to the Base Case, 2022-2051 (2022$ Millions)

	Base	Preferred	Alternate	Difference (Alternate - Preferred)
Residential	-	$3	$5	$2
Commercial	-	$2	$3	$1
Industrial	-	$1	$1	$0
Total	**-**	**$7**	**$9**	**$2**

Notes: All values are average annual values over the period from 2022 to 2051 in millions of 2022 dollars. Dollar year conversions are based on inflation rate information, as provided by the Companies.
Source: NERA calculations as explained in text.

31. Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ECONOMIC IMPACTS ANALYSIS.

A. **Table Harrison Direct-9** provides estimates of the differences in economic outcome measures for selected years in Nevada for the two Amendment cases relative to the Base Case and the differences in economic outcome measures for the Alternate Plan relative to the Preferred Plan. The relative economic impacts of the two Amendment cases vary over the selected years and over the 30-year period from 2022-2051, reflecting the different timing of construction and other major initial changes in economic activity.

Table Harrison Direct-9. Growth in Nevada Economy Relative to the Base Case, 2022-2051

	Nevada Economic Impact						
	2022	2023	2024	2025	2035	2045	205
Base							
Gross State Product (millions of 2022 dollars)	-	-	-	-	-	-	-
Personal Income (millions of 2022 dollars)	-	-	-	-	-	-	-
State & Local Tax Revenue (millions of 2022 dollars)	-	-	-	-	-	-	-
Employment (total jobs)	-	-	-	-	-	-	-
Preferred							
Gross State Product (millions of 2021 dollars)	42.0	114.0	15.0	5.0	-3.0	1.0	1.
Personal Income (millions of 2021 dollars)	26.0	70.0	5.0	1.0	-1.0	3.0	2.
State & Local Tax Revenue (millions of 2021 dollars)	2.60	7.00	0.50	0.10	-0.10	0.30	0.2
Employment (total jobs)	445	1,181	139	18	2	30	2
Alternate							
Gross State Product (millions of 2022 dollars)	15.0	105.0	48.0	9.0	-5.0	2.0	3.
Personal Income (millions of 2022 dollars)	9.0	66.0	26.0	0.0	-2.0	4.0	4.
State & Local Tax Revenue (millions of 2022 dollars)	0.90	6.60	2.60	0.00	-0.20	0.40	0.4
Employment (total jobs)	169	1,130	537	42	-8	44	3
Difference (Alternate - Preferred)							
Gross State Product (millions of 2022 dollars)	-27.0	-9.0	33.0	4.0	-2.0	1.0	2.
Personal Income (millions of 2022 dollars)	-17.0	-4.0	21.0	-1.0	-1.0	1.0	2.
State & Local Tax Revenue (millions of 2022 dollars)	-1.7	-0.4	2.1	-0.1	-0.1	0.1	0.
Employment (total jobs)	-276	-51	398	24	-10	14	1

Notes: The Base Case is assumed to be the REMI Baseline scenario; expenditure and electricity revenue inputs thus are modeled for the two Amendment cases in comparison to the Base Case and impacts on economic outcomes are measured relative to the Base Case. Employment values include full time and part time jobs.
Source: NERA calculations as explained in text.

Table Harrison Direct-10 provides estimates of the average annual economic impacts in Nevada over the 30-year period from 2022-2051 for the two Amendment cases relative to the Base Case as well as the differences in average annual impacts for the Alternate Plan relative to the Preferred Plan. These results indicate that both Amendment cases have positive economic impacts relative to the Base Case for all four economic impact measures. These results also indicate that the relative economic impacts of the two Amendment cases differ for the four impact categories. The estimated annual impacts are greater for the Alternate Plan than the

Preferred Plan for gross state product (by about $200,000) and for employment (by about 4 jobs). The estimated annual impacts are smaller for the Alternate Plan than the Preferred Plan for personal income (by about $100,000) and for state and local tax revenue (by about $10,000).

Table Harrison Direct-10. Average Annual Differences in Nevada Economic Impacts Relative to the Base Case, 2022-2051

	Base	Preferred	Alternate	Difference (Alternate - Preferred)
Gross State Product (millions of 2022 dollars)	-	3.4	3.6	0.2
Personal Income (millions of 2022 dollars)	-	2.4	2.3	-0.1
State & Local Tax Revenue (millions of 2022 dollars)	-	0.24	0.23	-0.01
Employment (total jobs)	-	48	52	4

Notes: The Base Case is assumed to be the REMI Baseline scenario; expenditure and electricity revenue inputs thus are modeled for the two Amendment cases in comparison to the Base Case and impacts on economic outcomes are measured relative to the Base Case. Employment values include full time and part time jobs.
Source: NERA calculations as explained in text.

X. CONCLUSION

32. Q. PLEASE PROVIDE ESTIMATES OF THE PWSC FOR THE CASES BASED UPON YOUR ESTIMATES OF ENVIRONMENTAL COSTS.

A. **Table Harrison Direct-11** provides estimates of the PWSC for the two Amendment cases. As I indicated in discussing the objectives of my testimony, PWSC is defined as the sum of the PWRR and the environmental costs. These results indicate that the PWSC is greater for the Alternate Plan than for the Preferred Plan by about $108.2 million.

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

Table Harrison Direct-11. Present Worth of Societal Costs, 2022-2051 (2022$ Millions)

	Preferred	Alternate	Difference (Alternate- Preferred)
PWRR	$27,745.2	$27,800.2	$55.0
Conventional Air Emission Costs	$60.2	$60.8	$0.6
Additional Water Costs	$10.7	$10.6	-$0.1
Social Costs of Carbon	$5,291.4	$5,344.1	$52.7
PWSC	$33,107.5	$33,215.7	$108.2

Notes: All values are present values as of 2022 in millions of 2022 dollars for the period 2022-2051. For conventional air emissions and water cost present values are calculated using nominal annual discount rates of 7.14 percent for Nevada Power and 6.75 percent for Sierra. The social cost of carbon values are based upon a 3 percent annual discount rate used to calculate global environmental costs.
Source: NERA calculations as explained in text.

33. Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE NET ECONOMIC BENEFITS OF THE CASES BASED UPON YOUR ESTIMATES OF ECONOMIC IMPACTS.

A. Both the Preferred Plan and the Alternate Plan have positive impacts on the Nevada economy relative to the Base Case for all four economic impact measures. The economic impacts are larger for the Alternate Plan than the Preferred Plan for two impact measures and smaller for two impact measures.

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

A. Yes, it does.

NERA
Economic Consulting

David Harrison, Ph.D.
Managing Director

National Economic Research Associates, Inc.
99 High Street, 16th Floor
Boston, Massachusetts 02110
+1 617 927 4500 Fax +1 617 927 4501
Direct dial: +1 617 927 4512
david.harrison@nera.com

David Harrison
Managing Director

Dr. David Harrison is a Managing Director at NERA Economic Consulting and co-head of NERA's global environment practice. He has extensive experience evaluating the economic effects of a wide range of policies and programs as a consultant, academic and government official.

Dr. Harrison has extensive experience over more than two decades evaluating the costs and benefits of air quality regulations under the Clean Air Act and other social regulatory policies, including various health and safety regulations. This experience includes evaluating the potential environmental benefits/damages associated with air emissions taking into account information on emissions, air quality concentrations, population exposure, and dose-response relationships. The various cost-benefit and cost-effectiveness studies have been done for a large number of sectors, including electricity, automobile, trucking, marine, chemical, iron and steel, petroleum, pulp and paper, small utility engines, small handheld equipment, snowmobiles, construction equipment, and others. He and his colleagues have worked closely with company officials and collaborated with various technical consultants in the development of information on these programs. The results of these analyses have been presented to company officials, government agencies, and the media.

Dr. Harrison has been active in the development and economic assessment of climate change policies around the world. He participated in the development or evaluation of major greenhouse gas programs and proposals in the United States, including those in California, the Northeast, the Midwest and various federal initiatives, as well as programs in Europe and Australia. He and his colleagues assisted the European Commission and the UK government with the design and implementation of the European Union Emissions Trading Scheme and national European programs related to climate change, renewable policies, and energy efficiency policies. He also has directed numerous projects for individual companies and trade associations—including those in electricity, oil and gas, refining, petrochemical, pulp and paper, cement, iron and steel, chemical, aluminum and other sectors—to evaluate the potential effects of climate change policies. Dr. Harrison and his colleagues have used NERA's proprietary energy-macroeconomic model (NewERA) to evaluate the potential economic impacts of a U.S. carbon tax and to evaluate the potential economic impacts of federal regulations on carbon dioxide emissions from existing power plants. He has lectured frequently on climate change and related topics at numerous conferences in the United States and abroad.

Dr. Harrison has directed benefit-cost analyses for numerous electric power plants under Section 316(b) of the Clean Water Act and other regulations related to water quality. These have included facilities on the major water bodies, including the Atlantic Coast, the Great Lakes, the Pacific Coast, and various rivers. The power plants have included numerous nuclear and fossil units. These assessments have included estimates of the potential impacts on electricity cost and reliability using detailed electricity market models in various electricity regions of the United States. Dr. Harrison has testified regarding these cost-benefit assessments in numerous state workshops and administrative hearings. He also has assisted the Utility Water Act Group (UWAG), the Edison Electric Institute (EEI) and individual utilities in their evaluation of the EPA 316(b) regulations as well as of EPA effluent guideline regulations. He has presented the results of these assessments to senior EPA and OMB officials. Dr. Harrison was a co-signer of an Amicus Brief submitted to the Supreme Court of the United States regarding the comparison of benefits and costs under Section 316(b) of the Clean Water Act.

Dr. Harrison has directed numerous studies of the local and state economic impacts of policies and programs, including those related to transportation (airports, highways, airlines), housing and tourism activities, energy (power plants, natural gas pipelines and others), remediation (Superfund and other environmental remediation), manufacturing and mining activities (including mining, chemical, petrochemical, automotive, and many others), and large commercial and retail developments. He has developed estimates of the cumulative national and global contributions of these local and state contributions. The local and state analyses have used state-of-the-art model developed by Regional Economic Models, Inc. (REMI) and IMPLAN, as well as customized models developed by NERA based upon available data. These economic impact projects have been developed for numerous metropolitan areas within the U.S. and the rest of the world, for virtually all states in the U.S. as well as for individual countries in Africa, Europe, and the Caribbean. The results of these studies have been presented to numerous public and private groups as well as to the media.

On the national level, in addition to developing estimates of the cumulative national impacts on local economies, Dr. Harrison has worked with colleagues to develop macroeconomic assessments of the impacts of major national policies and programs on the U.S. and state economies. Assessments have included studies of the U.S. Environmental Protection Agency's (EPA's) Clean Power Plan to reduce carbon dioxide emissions, EPA's potential regulations for ambient air quality standards for ozone, EPA's proposed effluent guidelines, cumulative effects of EPA air, coal combustion residuals, and cooling water regulations, and a potential carbon tax, all of which were based upon the use of the NewERA model, NERA's integrated electricity, energy and macroeconomic model.

Before joining NERA, Dr. Harrison was an Associate Professor at the John F. Kennedy School of Government at Harvard University, where he taught microeconomics, energy and environmental policy, cost-benefit analysis, transportation policy, regional economic development, and other courses for more than a decade. He also served as a Senior Staff Economist on the U.S. government's President's Council of Economic Advisors, where he had responsibility for environment and energy policy issues. He is the author or co-author of two books on environmental policy and numerous articles on various topics in professional journals.

Dr. Harrison received a Ph.D. in Economics from Harvard University, where he was a Graduate Prize Fellow. He holds a B.A. *magna cum laude* in Economics from Harvard College, where he was a member of Phi Beta Kappa, and a M.Sc. in Economics from the London School of Economics, where he was the Rees Jeffreys Scholar.

Education

Harvard University
Ph.D., Economics, 1974
M.A., Economics, 1972

London School of Economics and Political Science
M.Sc., Economics, 1968

Harvard University
B.A., Economics, *magna cum laude,* 1967

Professional Experience

National Economic Research Associates, Inc.
1988- *Managing Director, Senior Vice President, Vice President.* Directs projects in the economics of the environment, energy, transportation, regional economic development and other areas.

Putnam, Hayes & Bartlett, Inc.
1987-1988 *Senior Associate*. Directed projects in the economics of energy, antitrust, and other areas.

Dun & Bradstreet Technical Economic Services
1985-1987 *Director of Product Development*. Directed economic studies in energy, transportation, and industrial location.

John F. Kennedy School of Government, Harvard University
1980-1985 *Associate Professor*. Areas of instruction: microeconomics; benefit-cost analysis; environment; energy; natural resource economics; urban economics; public finance; transportation; law and economics. Participant, Harvard Faculty Project on Regulation. Faculty Steering Committee, Energy and Environmental Policy Center. Principal investigator in research grants.

President's Council of Economic Advisors

1979-1980 *Senior Staff Economist*. Worked with other White House staff and agency officials on domestic issues. Areas of responsibility included energy, environment and transportation. Principal staff on the Regulatory Analysis Review Group. Principal White House staff for the review of Administration policy regarding the automotive industry.

Department of City and Regional Planning, Harvard University

1974-1979 *Assistant and Associate Professor*. Areas of instruction: microeconomics; statistics; econometrics; transportation; environment; urban development; and housing policy. Participant, MIT-Harvard Joint Center for Urban Studies. Faculty Chairman, Concentration in Land Use and Environment.

National Bureau of Economic Research

1974 *Research Associate*. Co-author of benefit-cost study of automotive air pollution prepared by the National Academy of Sciences for the Committee on Public Works, U.S. Senate.

U.S. Department of Transportation

1973-1974 *Economist*. Performed economic studies of transportation issues, including urban mass transportation, automobile emission and safety programs, and highway finance.

Department of Economics, Harvard University

1970-1974 *Teaching Fellow and Assistant Head Tutor*. Areas of instruction: microeconomics; macroeconomics; econometrics; transportation; public finance; environmental policy; and housing policy.

The Urban Institute

1971 *Research Economist*. Participated in econometric studies as participant in the Program on Local Public Finance.

U.S. Department of Housing and Urban Development

1969 *Economist*. Participated in economic evaluations of HUD infrastructure programs, primarily the water and sewer grant program.

Honors and Professional Activities

Summa cum Laude, Senior Honors Thesis, Harvard University.

Phi Beta Kappa, Harvard University.

Rees Jeffreys Scholar in the Economics of Transport, London School of Economics.

Graduate Prize Fellowship, Harvard University.

Member, American Economic Association.

Member, Association of Environmental and Resource Economists.

Member, International Association of Energy Economists.

Member, Public Policy for Surface Freight Transportation Study, Transportation Research Board, National Research Council.

Member, Advisory Committee, Massachusetts Department of Environmental Quality Engineering.

Member, Peer Review Panel, National Acid Precipitation Assessment Program.

Member, Public Health and Socio-Economic Task Force, South Coast Air Quality Management District (Los Angeles).

Member, Marketable Permits Advisory Committee, South Coast Air Quality Management District (Los Angeles).

Member, Socioeconomic Technical Review Committee, South Coast Air Quality Management District (Los Angeles).

Member, Harvard Graduate Society Council.

Member, RECLAIM Advisory Committee (Los Angeles).

Member, Board of Trustees, Cambridge Health Alliance (Harvard Medical School Teaching Hospital).

Participant, Aspen Institute Dialogue on Climate Change.

Member, U.S. Government Accountability Office Expert Panel on International Greenhouse Gas Emissions Trading.

Consultant to the following public and private organizations:

U.S. Environmental Protection Agency; U.S. Department of Transportation; Massachusetts Port Authority; Organization for Economic Cooperation and Development (OECD, Paris); European Commission Directorate-General Environment; Civil Aeronautics Board; Italian Ministry of Environment; Massachusetts Department of Environmental Protection; UK Department of Transport; UK Department for Environment, Food and

Rural Affairs, UK Department of Trade and Industry, City of Chicago Department of Aviation; Conference Board of Canada; South Coast Air Quality Management District; Massachusetts Department of Environmental Management; and numerous state and local governments, trade associations, and private firms.

Reviewer for the following professional journals:

American Economic Review; Review of Economics and Statistics; Journal of Political Economy; Journal of Environmental Economics and Management; Journal of Urban Economics; Journal of Regional Science; Journal of Policy Analysis and Management; and Public Policy.

I. Publications

A. Books

Who Pays for Clean Air. Cambridge, MA: Ballinger Publishing Company, 1975.

The Automobile and the Regulation of Its Impact on the Environment (co-author). Norman, OK: Oklahoma University Press, 1975.

B. Articles and Published Reports

The Challenge of Measuring Pipelines' GHG Footprints, Law360, May 2020.

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Climate Change Risks and Opportunities: How Companies Can Develop Information to Comply with SEC Guidance Regarding Climate Change Disclosure (with Andrew Foss), NERA Economic Consulting, February 2010.

A Victory for Economic and Environmental Rationality: Supreme Court Allows Cost-Benefit Analysis in Setting Important Clean Water Act Standards, NERA Economic Consulting, May 2009.

What Every Company Should Do to Prepare for a Mandatory US Greenhouse Gas Cap-and-Trade Program, in *Climate Policy Economics Insights*, NERA Economic Consulting, March 2009.

Now the Hard Work: How to Get the "Biggest Bang for the Buck" from the Federal Economic Stimulus Package, NERA Economic Consulting*,* February 2009.

Evaluation of Borrowing as a Method to Contain Costs in a Greenhouse Gas Emissions Cap-and-Trade Program (with Albert Nichols), Electric Power Research Institute, December 2008.

"Using Emissions Trading to Combat Climate Change: Programs and Key Issues" (with Per Klevnas, Albert Nichols and Dan Radov) in *Environmental Law Reporter*, June 2008.

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"Assessing the Financial Consequences to Firms and Households of a Downstream Cap-And-Trade Program to Reduce U.S. Greenhouse Gas Emissions" in *A Climate Policy Framework: Balancing Policy and Politics*, John A. Riggs, ed., Washington, DC: The Aspen Institute, 2004.

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IV. Presentations

A. Climate Change

"National Carbon Policies: Looking Backward and Looking Forward," presented at LSI Conference on Combating Climate Change in the Pacific Northwest, Seattle, Washington, June 6, 2018.

"Energy and Economic Impacts of the Clean Power Plan," presented to the American Coalition for Clean Coal Electricity, November 2015.

"A Carbon Dioxide Standard for Existing Power Plants: Impacts of the NRDC Proposal," presented to the American Coalition for Clean Coal Electricity, March 2014.

"Offsets in Potential EPA GHG Tradable Performance Standard for Existing Power Plants: Preliminary Assessment," Presentation to the Electric Power Research Institute Environment & Renewable Program Advisory Meeting, Kansas City, Missouri, September 24, 2013.

"The Interactions of Complementary Policies with a GHG Cap-and-Trade Program: The Case of Europe," presentation at the EPRI-IETA Joint Symposium, San Francisco, April 16, 2013.

"Incentives for International Sectoral Crediting Mechanisms," presented at the Workshop on New Market Mechanisms organized by the International Emissions Trading Association and Enel S.p.A., Brussels, October 13, 2011.

"The Copenhagen Conference: International Climate Policy and Implications for US Policy," presented at the Fenway Colleges Climate Change Teach-In, Washington, DC, February 25, 2010.

"U.S. Greenhouse Gas Cap-and-Trade Programs and Cost Containment," presented at the EUEC 2010 Energy & Environment Conference, AZ, Phoenix, February 1, 2010.

"Financial Implications of a US Cap-and-Trade Program for Sectors and Companies," presented at 2nd Annual Carbon Trading Summit, New York City, January 13, 2010.

"Lessons Learned from the European Union Emissions Trading Scheme," presented to California State Senate Select Committee on Climate Change and AB 32 Implementation, Sacramento, CA, January 7, 2010.

"Greenhouse Gas Emissions Cap-and-Trade Program: Key Design Elements," presented at the IETA Fall 2009 Symposium, Washington, DC, November 3, 2009.

"Compliance Flexibility in Domestic Greenhouse Gas Cap-and-Trade Programs," presented to the 9th Annual Workshop on Greenhouse Gas Emissions Trading sponsored by the Electric Power Research Institute, the International Energy Agency, and the International Emissions Trading Association, Paris, September 14, 2009.

"Allocation Decisions in the European Union Emissions Trading Scheme," presented to the California Economic and Allocation Advisory Committee, July 1, 2009.

"Economic Analysis of Waxman-Markey Climate Bill (ACES)," presented as part of Environmental Markets Association Webinar, June 4, 2009.

"Climate Policy Risks for Electric Utilities: Economic Modeling to Assist Utilities in Responding to Climate Change Programs," presented at the Utility Rate Case Conference organized by Law Seminars International, Las Vegas, NV, February 6, 2009.

"Cost-Containment in a U.S. Greenhouse Gas Cap-and-Trade Program," presented at the EEI Fall 2008 Legal Conference, Boston, October 30, 2008.

"Climate Change and Electricity Prices: What Should Electricity Companies Do," presented at the EUCI Conference on Electricity, Chicago, September 30, 2008.

"The EU Energy and Climate Package: Interactions between EU Policies and Targets and Implications for CO2 Price Uncertainty," presented at the IEA/IETA/EPRI 8th Annual Workshop on Greenhouse Gas Emissions Trading, Paris, September 23, 2008.

"European Union Emissions Trading Scheme: Overview and Implications for the U.S.," presented at the Second Carbon Trading Summit, New York, NY, June 24, 2008.

"Carbon Emissions Trading and Allocation: Complexities of Policy Choices," presented at the IETA/AIGN Workshop, Canberra, Australia, March 5, 2008.

"Climate Change: What Every Company Should Do to Get Ready for a Mandatory Emissions Trading Program," presented at NERA Economic Consulting Workshop, Sydney, Australia, March 4, 2008.

"Workshop on Carbon Emissions Trading: EU and US Experience and Implications for IP/Australia," presented before International Power, Melbourne, Australia, March 3, 2008.

"Design Elements for Potential Canadian GHG Cap-and-Trade Program," presented at the Cap and Trade Working Group Retreat, Toronto, Ontario, January 31, 2008.

"Allocation in the EU ETS: What Have We Learned?" presented at the MIT workshop on EU ETS, Washington, DC, January 24, 2008.

"Emissions Trading: Background, Prior Programs and Implications for a U.S. Carbon Cap-and-Trade Program," presented at ALI-ABA Course on Clean Air: Law, Policy and Practice, Washington, DC, November 9, 2007.

"Overview of the European Union Emissions Trading Scheme for Carbon Dioxide," presented at EEI's 2007 Fall Legal Conference, Napa, California, October 4, 2007.

"Evaluating the Financial Impacts of Potential Carbon Cap-and-Trade Programs on Electricity Companies: What Every Electricity Company Should Do to Get Ready for Mandatory Climate Change Policy," presented at the Carbon Constraint Conference, Chicago, September 13, 2007.

"EU ETS Allocation Options: Reconciling Complexities and Simplicity/Transparency," presented before the IETA-CEPS Climate Change Conference, Brussels, Belgium, June 26, 2007.

"Overview of Allocation Methodologies and Principles," presented before the European Climate Change Programme working group on emissions trading, Brussels, Belgium, May 21, 2007.

"Allocation Choices for a Carbon Trading Program," presented at the Carbon Expo, Cologne, Germany, May 3, 2007.

"Allocation Choices and International Considerations," presented to Senate staff members, Washington, DC, February 2, 2007.

"Carbon Financial Analyses for Electricity Companies," presented at the Electric Utilities Environmental Conference, Tucson, Arizona, January 23, 2007.

"Carbon Emissions and State Electric Utility Regulation," presented at the Electric Utilities Environmental Conference, Tucson, Arizona, January 22, 2007.

"European Union Emissions Trading Scheme for Carbon Dioxide: Lessons and Implications," presented at North America and The Carbon Markets Conference hosted by Point Carbon and Pew Center on Global Climate Change, Washington, DC, January 18, 2007.

"Policy Design Side By Side: What Elements Matter," presented at North America and the Carbon Markets Conference hosted by Point Carbon and Pew Center on Global Climate Change, Washington, DC, January 17, 2007.

"European Union," presented at North America and the Carbon Markets Conference hosted by Point Carbon and Pew Center on Global Climate Change, Washington, DC, January 17, 2007.

"Carbon Markets, Linking, and Cost Containment," presented at the IEA/IETA/EPRI 6th Annual Emissions Trading Workshop, Paris, France, September 27, 2006.

"Auctioning Experience in Other Sectors and Implications for Designing a Carbon Auction," presented at the IETA Workshop on Allocation Methodologies, Paris, France, September 25, 2006.

"European Carbon Markets and Implications for a US Carbon Constrained Future," presented at Preparing for a Carbon Constrained Future Conference hosted by Electric Utility Consultants, Inc., Arlington, Virginia, June 28, 2006.

"Overview of the European Union Emissions Trading Scheme," presented to staff of the Senate Committee on Energy and Natural Resources, Washington, DC, June 16, 2006.

"Policies to Address Potential EU ETS Impacts on Power Prices and Industrial Competitiveness," presented at the CEPS/IETA Climate Change Conference, Brussels, Belgium, May 30, 2006.

"Learning from Experience: First Year of the European CO_2 Emissions Trading Scheme," presented to New Prospects for Climate Change Regulation Panel organized by Harvard Law School, March 10, 2006.

"Carbon Policies and Electric Utility Rate Cases," presented at the Managing the Modern Utility Rate Case Conference organized by Law Seminars International, Las Vegas, NV, February 14, 2006.

"Beyond Cost: Carbon Markets, Electricity Prices and 'Windfall Profits,'" presented to Electric Utilities Environmental Conference, Tucson, AZ, January 23, 2006.

"European CO_2 Emissions Trading Scheme: First Year Accomplishments and Implications," presented at an International Emissions Trading Association side event at the 11th Conference of the Parties to the Kyoto Protocol, Montreal, December 5, 2005.

"Allocation Choices for a U.S. Carbon Dioxide Emissions Trading Scheme," presented to National Commission on Energy Policy, Workshop on Allowance Allocation, Washington, DC, September 30, 2005.

"Carbon Markets, Electricity Prices and Windfall Profits: Emerging Information on the European Union Emissions Trading Scheme" presented to IEA-IETA-EPRI Emissions Trading Workshop, Paris, September 27, 2005.

"U.S. State-level Climate Regimes: Lessons from the U.S. and Europe, presented to Fourth Annual Green Trading Summit, New York, NY, May 2, 2005.

"Overview of Allocation Choices: Alternatives and Implications," presented to Stakeholder Workshop, Regional Greenhouse Gas Initiative, Boston, MA, October 14, 2004.

"Emissions Trading: Concepts, Experience, Lessons, and Implications Greenhouse Gas Programs," presented to Iberdrola, Cambridge, MA, March 25, 2004.

"How CEPCO Can Gain from CO_2 Trading," presented to Chubu Electric Power Co., Inc., Nagoya, Japan, November 25, 2003.

"The Rise of Emissions Trading in Air Quality and Climate Change Policy," presented to EPRI Environmental Sector Council, San Antonio, Texas, September 12, 2003.

"Greenhouse Gas Emissions Trading and Firm Risk Management Behavior", presented to the ARPEL-IPIECA Workshop, A Practical Approach to Identifying Emission Reduction Opportunities: Examples under the Kyoto Mechanisms in Latin America and the Caribbean, San Jose, Costa Rica, December 3, 2002.

"Initial Allocations in Various Systems of Emissions Trading" presented to the Exploring New Approaches in Regulating Industrial Installations (ENAP) Workshop on Emissions Trading for NO_X and SOx in Europe, The Hague, Netherlands, November 22, 2002.

"Overview of Alternative Allocations for European GHG Trading Program," presented to IEA-EPRI-IETA Workshop on Greenhouse Gas Emissions Trading, Paris, September 17, 2002.

"Evaluation of Alternative Allocations for European GHG Trading Program," presented to IEA-EPRI-IETA Expert Meeting: Allocation of GHG Objectives, Paris, September 16, 2002.

"Greenhouse Gas Emission Trading Programs," presented to Chubu Electric Company, Cambridge, MA, July 16, 2002.

"Evaluation of Alternative Allocations for European GHG Trading Program," presented to Chubu Electric Company, Cambridge, MA, July 16, 2002.

"Corporate Strategies and Practices for GHG Emission Reduction," presented to Chubu Electric Company, Cambridge, MA, July 15, 2002.

"Emission Trading: Concepts, Experience, and Lessons from Non-Greenhouse Gas Programs," presented to Chubu Electric Company, Cambridge, MA, July 15, 2002.

"Prospects for the EU Greenhouse Gas Trading Program," presented to EPRI Global Climate Change Research Seminar, Washington, DC, June 4, 2002.

"Evaluation of Alternative Allocations for European GHG Trading Program," presented to European Commission, Brussels, Belgium, November 13, 2001.

"Evaluation of Alternative Allocations for European GHG Trading Program," presented to ENVECO, Brussels, Belgium, November 13, 2001.

"CO_2 Permit Allocations: Evaluation of Alternatives for the EC," presented to the European Commission, Brussels, Belgium, March 5, 2001.

"Setting Baselines for Greenhouse Gas Trading: Lessons from Experience," presented to United Nations Framework Convention on Climate Change, Bonn, Germany, June 10, 2000.

"Setting Baselines for Greenhouse Gas Programs: Lessons from Experience," presented at the EPRI Global Climate Change Research Seminar, Washington, DC, May 18, 2000.

"Emissions Trading and Developing Countries: Implications of U.S. Experience and World Bank Role," presented at World Bank – Energy Week 2000, Washington, DC, April 13, 2000.

"Domestic GHG Trading: Assessing Impacts on Electric Utilities," presented to Electric Power Research Institute, Washington, DC, February 17, 2000.

"Energy-Environmental Policy Integration & Coordination (E-EPIC), U.S. Economic Growth & Health," presented to Electric Power Research Institute, Washington, DC, May 13, 1999.

"Priorities for the Development of GHG Trading Programs: Implications of the United States Experience," presented to the EPRI Global Climate Change Area Meeting, San Diego, California, January 26, 1999.

"Priorities for the Development of GHG Trading Programs: Implications of the United States Experience," presented to the Air & Waste Management Association Specialty Conference on Global Climate Change, Washington, DC, October 14, 1998.

"International Greenhouse Gas Trading," presented to the American Council for Capital Formation, Washington, DC, September 23, 1998.

"International Greenhouse Gas Emission Trading: Promise and Performance," presented to the EPRI Global Climate Change Research Seminar, Washington, DC, May 27, 1998.

"International Greenhouse Gas Trading: A 'Silver Bullet' Train?" presented to Sidebar Meeting, United Nations Framework Convention on Climate Change, Bonn, Germany, October 23, 1997.

"International Greenhouse Gas Trading," presented to the American Council for Capital Formation Conference on Global Warming, Washington, DC, September 24, 1997.

"International Greenhouse Gas Trading," presented to the National Association of Manufacturers, Washington, DC, September 17, 1997.

"International Greenhouse Gas Trading," presented to the American Automobile Manufacturers Association, Washington, DC, May 1, 1997.

"Emission Trading: Alternative Approaches, Experience and Implications for CO_2," prepared for the AAMA Climate Change Task Force, Washington, DC, September 27, 1996.

"Treatment of Greenhouse Gas Emissions in Electric Utility Resource Planning," prepared for the Third Conference on External Costs, *Internalization of Social Costs of Energy Conservation and Transportation in the United States and Europe for a Sustainable Development*, Ladenburg, Germany, May 29, 1995.

"Distributive Impacts of Economic Instruments for Greenhouse Gas Abatement," presented at the Air & Waste Management Association International Specialty Conference *Global Climate Change: Science, Policy and Mitigation Studies*, Phoenix, Arizona, April 6, 1994.

"New Approaches for Controlling Global Warming," presented to the Conference on Global Warming, Vermont Law School, South Royalton, Vermont, February 16, 1990.

B. Economic Impact Assessments

"Economic Assessments at Tier 2 Superfund Sites," presented at The 34th Annual International Conference on Soils, Sediments, Water and Energy, Amherst, Massachusetts, October 15, 2018.

"Economic Impacts of a 65 ppb National Ambient Air Quality Standard for Ozone," Webinar, (with Anne E. Smith), prepared for the Association of Air Pollution Control Agencies, March 2, 2015.

"Cumulative Energy Market Impacts of Various Environmental Regulations," presented at Law Seminars International, Utility Rate Case Issues and Strategies 2013, Las Vegas, Nevada, February 21, 2013.

"Financial Implications of a US Cap-and-Trade Program for Sectors and Companies," presented at 2nd Annual Carbon Trading Summit, New York City, January 13, 2010.

"Evaluating the Impact of Future E.U. Chemical Policy on the French Economy," presented to REMI Northeast Policy Analysis and Users' Conference, Boston, MA, January 31, 2006.

"Background on NERA Study 'Socioeconomic Effects of the Niagara Power Project and Local NYPA Presence'," presented to Niagara Power Project Relicensing Stakeholder Meeting, Niagara Falls, NY, November 13, 2003.

"Economic Benefits to the Chicago Region from the Whitecap Energy System," presented to the Illinois Department of Natural Resources, Springfield, Illinois, January 30, 2001.

"Fueling Electricity Growth for a Growing Economy," presented to Edison Electric Institute, Palm Springs, California, January 13, 2000.

"Economic Impact Analyses with REMI: Two Case Studies," presented to the REMI Seminar, Miami, Florida, October 6, 1997.

"Impacts on the Hawaii Economy of Alternative Resource Plans for Oahu," presented to the Hawaiian Electric Company IRP Advisory Group, Honolulu, Hawaii, July 24, 1997.

"Economic and Environmental Effects in Maine of the Maritimes & Northeast Pipeline Project," presented to the Maine Economic Development Council, Rockland, Maine, February 12, 1997.

"Economic and Environmental Effects of the Maritimes & Northeast Pipeline Project," presented to a media conference and Editorial Boards of the *Bangor Daily News*, the *Portland Press Herald,* and the *Kennebec Journal,* Bangor and Augusta, Maine, November 21, 1996.

"Assessing the Economic Impacts of Alternative HECO Resource Plans," presented to the PSP&ED Advisory Group of the Hawaiian Electric Company, Honolulu, Hawaii, July 3, 1996.

"The Lake Calumet Airport and Chicago's Economic Future," presented to the Lake Calumet Airport Advisory Committee, Chicago, Illinois, July 2, 1991.

"Socioeconomic Impacts of Proposed Rule 431.2," prepared for Southern California Edison and presented to the South Coast Air Quality Management District, Los Angeles, California, May 4, 1990.

"An Economist Looks at the Federal Regulation of Biotechnology," presented to the Conference on Emerging Issues in Biotechnology, sponsored by Boston University Law School, Boston, Massachusetts, March 2, 1990.

C. Air Quality

"Economic Impacts of a 65 ppb National Ambient Air Quality Standard for Ozone," Webinar, (with Anne E. Smith), prepared for the Association of Air Pollution Control Agencies, March 2, 2015.

"Cost-Effectiveness of Alternative Wood Stove New Source Performance Standards," (with Andrew Foss), presentation to the U.S. Environmental Protection Agency, Raleigh, NC, February 28, 2013.

"Potential Impacts of EPA Air, Coal Combustion Residuals, and Cooling Water Regulations," presented to the U.S. Environmental Protection Agency, November 21, 2011.

"Potential Impacts of EPA Air, Coal Combustion Residuals, and Cooling Water Regulations," presented to the U.S. Office of Management and Budget, November 8, 2011.

"Potential Impacts of EPA Air, Coal Combustion Residuals, and Cooling Water Regulations," presented to the U.S. Treasury Department, October 26, 2011.

"Potential Impacts of EPA Air, Coal Combustion Residuals, and Cooling Water Regulations," presented to the White House Office of Public Engagement, October 25, 2011.

"Economic Effects of State Restrictions on Interstate Mercury Trading," presented at the Electric Utilities Environmental Conference, Tucson, Arizona, January 22, 2007.

"Using Emissions Trading to Regulate Mercury Emissions in Montana," presented at a Public Hearing, Billings, Montana, June 1, 2006.

"Developing an Emissions Trading Program for Regional Haze," presented to Midwest RPO Regional Air Quality Workshop, Chicago, Illinois, June 28, 2005.

"Developing an Emissions Trading Program for Regional Haze," presented to the Visibility Improvement State and Tribal Association of the Southeast (VISTAS), via conference call from Boston, MA, June 1, 2005.

"Economic and Environmental Analyses of CARB Tier 3 Non-Handheld Exhaust Emission Regulations," presented to the California Air Resources Board staff in Sacramento, CA via videoconference from Boston, Massachusetts, September 18, 2003.

"Market Based Instruments and Shipping Emissions," presented to conference sponsored by DG Environment, Brussels, September 5, 2003.

"Economic and Environmental Analyses of CARB Tier 3 Non-Handheld Emission Regulations: Status Report and Preliminary Results", presented to Outdoor Power Equipment Institute and Engine Manufacturers Association (OPEI & EMA), Washington, DC, August 26, 2003.

"Ex Post Evaluation of the RECLAIM Emissions Trading Program for the Los Angeles Air Basin", presented to OECD Workshop on Ex Post Evaluation of Tradable Permits: Methodological and Policy Issues, Paris, January 21, 2003.

"Emissions and Cost-Effectiveness of the Pull-Ahead Requirements for Heavy Heavy-Duty Diesel Engines," presented to U.S. Office of Management and Budget, Washington, DC, July 24, 2002.

"Economic Analysis of Alternative EPA Snowmobile Regulations," presented to U.S. Environmental Protection Agency Office of Mobile Sources, Ann Arbor, Michigan, May 1, 2002.

"Impacts of ZEV Sales Mandate on California Fleet Emissions," presented to the California Air Resource Board, Sacramento, California, September 7, 2000.

"Economic Assessment of the Cost-Effectiveness of Alternative MACT Standards for the Metal Coil Surface Coating Industry," presentation to the U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, August 2, 2000.

"Economics and Environmental Regulation: Opportunities and Obstacles," presented to Crowell & Moring, LLP, Washington, DC, March 22, 2000.

"RECLAIM: A Comprehensive Approach to Air Quality Regulation," presented to Edison Electric Institute, Washington, DC, March 6, 2000.

"Economic Assessment of the Cost-Effectiveness of Alternative Phase 2 Regulations for Handheld Engines," presented to the U.S. Environmental Protection Agency and Office of Management and Budget, Washington, DC, February 14, 2000.

"Economic Assessment of the Cost-Effectiveness of Alternative Phase 2 Regulations for Handheld Engines," presented to the U.S. Environmental Protection Agency, Office of Mobile Sources, Washington, DC, October 12, 1999.

"Economic Assessment of the Cost-Effectiveness of Alternative Phase 2 Regulations for Handheld Engines," presented to the U.S. Environmental Protection Agency, Office of Mobile Sources, Ann Arbor, Michigan, October 8, 1999.

"Economic Impacts of ARB Staff Proposed Marine Emission Standards," presented to the California Air Resources Board Hearing, Sacramento, California, December 10, 1998.

"Cost-Benefit Analysis of MACT Standards for Boat Manufacturing," presented to the National Marine Manufacturers Association, Tampa, Florida, October 15, 1998.

"Economic Analyses of Alternative California Standards for Exhaust Emissions from Marine Engines," presented to California Air Resources Board, Sacramento, California, October 9, 1998.

"Tradable Permits for Air Pollution Control: The United States Experience," presented to the Organization for Economic Cooperation and Development Workshop on Domestic Tradable Permit Systems for Environmental Management, Paris, September 24, 1998.

"NO_X Trading Program to Implement EPA's SIP Call," presented to Indiana Department of Environmental Management, Indianapolis, Indiana, May 4, 1998.

"Economic Analysis of Alternative EPA Standards for Large CI Non-Road Engines: Draft NERA Results," presented to the Engine Manufacturers Association and the Equipment Manufacturers Institute, Chicago, Illinois, September 4, 1997.

"Cost-Effectiveness of ARB Small Off-Road Engine Regulations: Preliminary Results," presented to the California Air Resources Board, Sacramento, California, May 2, 1997.

"RECLAIM: Turning Theory Into Practice for Emissions Trading in the Los Angeles Air Basin," presented to the NERA Seminar on Tradable Permits, London, United Kingdom, April 11, 1997.

"RECLAIM: Turning Theory Into Practice for Emissions Trading in the Los Angeles Basin," presented to the *International Workshop on Tradable Permits, Tradable Quotas and Joint Implementation*, University of Sussex, Brighton, United Kingdom, April 9, 1997.

"Economic Analyses of Alternative ARB Regulatory Requirements for Small SI Non-Handheld Engines," presented to the California Air Resources Board staff, El Monte, California, February 4, 1997.

"Cost-Effectiveness of Alternative Emission Control Technologies for Small Utility Engines," presented to California Air Resources Board staff, El Monte, California, December 18, 1996.

"Emission Regulations for Non-Road Engines," presentation to the U.S. Environmental Protection Agency, Ann Arbor, Michigan, July 17, 1996.

"Valuation of Externalities: Methods and Examples," presented to the PSP&ED Advisory Group of the Hawaiian Electric Company, Honolulu, Hawaii, April 3, 1996.

"Valuation of Externalities: Experience and Methods," presented to the Hawaiian Electric Company Externalities Advisory Group, Honolulu, Hawaii, January 31, 1996.

"Emission Regulations for Small Utility Engines," presented to Small Non-Road Engine Regulatory Negotiations, Ann Arbor, Michigan, December 13, 1995.

"Economic Evaluation of Alternative Regulations of Exhaust Emissions from Small Utility Engines," presented to U.S. Environmental Protection Agency, Ann Arbor, Michigan, November 28, 1995.

“Emission Regulations for Small Utility Engines,” presented to California Air Resources Board staff, El Monte, California, October 3, 1995.

“Briggs & Stratton/NERA Phase 2 Economic Study,” presented to U.S. Environmental Protection Agency, Ann Arbor, Michigan, September 22, 1995.

“RECLAIM: Turning Theory Into Practice for Emissions Trading in the Los Angeles Basin,” presented to the Stanford Law School Environmental Markets Seminar, Stanford, California, March 8, 1995.

“Emission Trading for NO_X: Experience with RECLAIM,” presented to Edison Electric Institute, Washington, DC, May 26, 1994.

“Emission Trading for NO_X: The RECLAIM Experience,” presented to Edison Electric Institute, May 13, 1994.

“Projecting the Price of RECLAIM Trading Credits for NO_X,” presented at a California Energy Commission Workshop, Sacramento, California, February 4, 1994.

Comments on “Presumptive Pigouvian Tax: Complementing Regulation to Mimic an Emissions Fee,” presented to the Conference on Market Approaches to Environmental Protection, Stanford University, Palo Alto, California, December 3, 1993.

“Economic Effects of Regulatory Requirements to Protect Grand Canyon Visibility,” presented to the Grand Canyon Visibility Transport Commission, Salt Lake City, Utah, October 21, 1993.

“Evolving Role of Externalities in Utility Activities,” presented to the Electric Power Research Institute Energy Analysis Task Force, Nashville, Tennessee, September 29, 1993.

“External Costs of Electricity Generation in Southern Nevada,” presented on behalf of Nevada Power Company, at a workshop sponsored by the Nevada Public Service Commission, Las Vegas, Nevada, May 19, 1993.

“Environmental Externalities,” presented to Central and Southwest Corporation, Dallas, Texas, May 4, 1993.

“Creating Markets for Environmental Protection: Overview of Experience with Tradable Permit Systems,” presented at The Claremont Institute

Conference *Environmental Protection Through Market Incentives: A Strategy for the Future*, Los Angeles, California, January 20-21, 1993.

“Tradable Permits and Social Costing: The California Experience,” presented at the American Economic Association and Allied Social Science Association Meetings, Anaheim, California, January 6, 1993.

"The Distributive Impacts of Economic Instruments for Environmental Policy," presented to the OECD Group on Economic and Environmental Policy Integration, Paris, November 19, 1992.

"Emissions Trading: A Better Way to Incorporate Environmental Costs in Electric Utilities Resource Planning," presented at the Pace University

Center for Environmental Legal Studies Conference on *Incorporation of Social Costs of Energy in Resource Acquisition Decisions*, Racine, Wisconsin, September 8-11, 1992.

"Banking and Trading of Air Emission Reduction Credits," presented to the State of Connecticut Office of Policy and Management Meeting on Emissions Trading, Hartford, Connecticut, July 22, 1992.

"The Distributive Effects of Economic Instruments for Environmental Policy," presented to the OECD Group on Economic and Environmental Coordination, Paris, June 18, 1992.

"A Marketable Permits Program for the Los Angeles Air Basin," prepared for MIT Center for Energy and Environmental Policy Research *1992 New Developments Workshop*, Cambridge, Massachusetts, April 30, 1992.

"The Road From Theory to Practice: Developing a Marketable Permits Program for the Los Angeles Air Basin," seminar presented to the MIT Center for Energy and Environmental Policy Research, Cambridge, Massachusetts, March 11, 1992.

"Southern California Edison Damage-Based Values for Residual Emissions Valuation," presented to the California Energy Commission ER 92 Committee Workshop on Air Emission Damage Functions, Sacramento, California, January 29, 1992.

"Turning Theory Into Practice: Developing a Marketable Permits Program for the Los Angeles Basin," prepared for Project 88 -- Round II Seminar, John F. Kennedy School of Government, Harvard University, Cambridge, Massachusetts, December 11, 1991.

"Workshop on Economic Instruments," prepared for Imperial Oil Ltd., Toronto, Canada, October 1-2, 1991.

"Market-Based Approaches to Air Quality Improvement," presented to the Board of Directors of the California Council for Environmental and Economic Balance, San Diego, California, July 1991.

"Environment and Equity," presented to the Board of Directors of the California Council for Environmental and Economic Balance, San Diego, California, July 1991.

"Contribution of Economists to Environmental Policy: Comments on the Gruenspect-Lave Critical Review," presented to the Air and Waste Management Association, Vancouver, British Columbia, June 19, 1991.

"Airports and Economic Development," presented to the Southeast Chicago Development Commission, Chicago, Illinois, May 24, 1991.

"Environmental Economics in the 1990s," presented to the OECD Group of Economic Experts, Paris, May 16, 1991.

"The Clean Air Act: How to Make the Mandate Worth the Effort," presented to the Workshop on Emerging Environmental Policies and Business, North Carolina State University, Raleigh, North Carolina, April 18, 1991.

"Market-Based Approaches to Managing Air Emissions in California's South Coast Basin," presented to Workshop on Market Incentives, South Coast Air Quality Management District, El Monte, California, January 29, 1991.

"Market-Based Approaches to Managing Air Emissions in California's South Coast Basin," presented to the Steering/Advisory Committee on Market Incentives, South Coast Air Quality Management District, Los Angeles, California, December 11, 1990.

"How Environmental Policies Influence Natural Gas Markets," presented to the Conference on Emerging Competition in California Gas Markets, sponsored by the California Energy Commission, San Diego, California, November 9, 1990.

"Air Quality and Electric Vehicles," presented to the Electric Vehicle Symposium, sponsored by the Western Energy Supply and Transmission Associates, Ontario, California, November 8, 1990.

"Incorporating Environmental Impacts in Public Utility Commission Regulation," presented to the Energy Research Group, Washington, DC, November 6, 1990.

"The Promise and Performance of the Acid Rain Allowance Program," presented to the Conference on the New Acid Rain Legislation: Capitalizing on a Market-Based Approach, sponsored by Public Utilities Reports, Inc., Washington, DC, October 24, 1990.

"What Environmental Legislation Means for Crude Oil Marketers: A U.S. Overview," prepared for the Oxford College of Petroleum Studies, Long Beach, California, presented October 1, 1990.

"Market-Based Approaches for Environmental Improvement," presented to the Eleventh Annual Antitrust and Trade Regulation Seminar, sponsored by National Economic Research Associates, Santa Fe, New Mexico, July 5-7, 1990.

"Using Market-Based Approaches in the Energy Sector," presented to the OECD Economic Incentives Working Group, Paris, June 19-20, 1990.

"Emissions Trading: Concepts and Experience," prepared for The Canadian Electrical Association and presented at the *Workshop on Tradable Permits*, Toronto, Canada, June 13, 1990.

“Prototypical Trading Policy: Stationary Sources of NO_X,” prepared for NO_X/VOC Task Force and presented at the *Workshop on Flexible Mechanisms*, Montreal, Canada, June 6-7, 1990.

“Emissions Trading: An Overview of Concepts and Experience,” prepared for NO_X/VOC Task Force and presented at the *Workshop on Flexible Mechanisms*, Montreal, Canada, June 6-7, 1990.

“Market-Based Approaches for Environmental Improvement,” presented to the Board of Directors, The Conference Board of Canada, Edmonton, Canada, May 30, 1990.

“Market-Based Approaches for Environmental Protection: Lessons from the U.S. Experience,” presented to the Advisory Board, Research Program on Business and the Environment, The Conference Board of Canada, Toronto, Canada, April 24, 1990.

“Ozone and Economics,” presented to the Air and Waste Management Association, Los Angeles, California, March 20, 1990.

“Clear Thinking on Clear Air: Agenda for the 1990’s,” paper and panel discussion presented at the American Enterprise Institute’s Thirteenth Annual Policy Conference, Washington, DC, December 4, 1989.

“The Acid Rain Allowance Program,” presented to the Energy Research Group, Washington, DC, November 3, 1989.

D. Water Quality and Natural Resources

“316(b) Economic Assessments: Lessons Learned Over the Past Two Decades,” presented at EPRI Conference on Clean Water Act 316(b): Rule Compliance and Lessons Learned, Atlanta, Georgia, June 11, 2019.

“Benefits Evaluation and Monetization in EPA’s §316(b) Final Rule: Economic Issues,” presented at EPRI Conference on Technical Challenges for Implementing Clean Water Act §316(b) at Power Plants Withdrawing Cooling Water from Reservoirs, Huntersville, North Carolina, May 18, 2018.

“Social Cost Analysis in Section 316(b) Cost Evaluation Studies,” presented to Electric Power Research Institute Section 316(b) Conference on Technical Challenges for Ohio/Tennessee River Basin Power Plants, Columbus, Ohio, March 15, 2017.

“Benefits Evaluation and Monetization in EPA's §316(b) Final Rule: Economic Determinations and Issues,” presented at EUCI Conference on 316(b) Final Rule, September 29, 2016.

“Cost-Benefit Assessments for 316(b): Some Implementation Issues,” presented at UWAG Webinar on 316(b) Implementation Issues, August 5, 2015.

“Benefit-cost Assessment of Section 316(b) Entrainment Alternatives,” presented at the EUCI Conference on 316(b), Providence, Rhode Island, October 8, 2014

“Benefit-Cost Analysis in Section 316(b) BTA Determinations: The Road Ahead,” presented at the American Fisheries Society Symposium, Seattle, Washington, September 6, 2011.

“Cost-Benefit Analysis for Fish Impingement and Entrainment Reduction at Pickering Nuclear Generating Station,” presented to Canadian Nuclear Safety Commission, Ottawa, Canada, October 29, 2009.

“Cost-Benefit Analysis for Fish Impingement and Entrainment Reduction at Pickering Nuclear Generating Station,” presented at Ontario Power Generation Inc. Stakeholder Workshop, Ontario, Canada, September 29, 2009

Uncertainty in §316(b) Compliance Demonstration: Case Study Including Monte Carlo Analysis,” presented at the UWAG/EPRI Conference on Technologies and Techniques for §316(b) Compliance, Atlanta, Georgia, September 7, 2006.

“Electricity System Impacts of Nuclear Shutdown Alternatives,” presented to New York City Council, New York, NY, May 7, 2002.

“Electricity System Impacts of Nuclear Shutdown Alternatives,” presented to Westchester County Board of Legislators Committee on Environment and Health, Westchester, New York, April 29, 2002.

“An Economic Approach to 316(b) BTA Determination,” presented to the UWAG 316(b) Technical Workshop for the Environmental Protection Agency, Annapolis, Maryland, January 25, 2001.

“Methodology for Cost-Benefit Assessment of Fish Protection Alternatives for the Mercer Facility,” presentation to the Mercer 316(b) Permit Team, Newark, New Jersey, August 8, 2000.

“Roadmap for Costs & Benefits of Fish Protection Alternatives for the Salem Facility,” presented to the Monitoring Advisory Committee, Mt. Laurel, New Jersey, December 9, 1999.

“Costs & Benefits of Fish Protection Alternatives at the Salem Generating Facility,” presented to the New Jersey Department Environmental Protection, Trenton, New Jersey, May 4, 1999.

“Natural Resource Damage Assessments: Economic Techniques,” presented to PSE&G, Newark, New Jersey, December 9, 1997.

“Use of Economic Analysis in Environmental Impact Statements and Other Regulatory Proceedings,” presented to Hudson River Utilities, New York, New York, November 19, 1997.

"Combining Science and Economics: The Case of Superfund," presented to ENVIRON, Princeton, New Jersey, May 16, 1995.

"Social Costing: Policy Overview," presented to the British Columbia Utilities Commission Social Costing Workshop, Vancouver, British Columbia, March 29, 1995.

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, DAVID HARRISON, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

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

Date: March 18, 2022

DAVID HARRISON

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

ANITA HART

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

First Amendment to the
2021 Joint Triennial Integrated Resource Plan (2022-2041)
Docket No. 22-03___

Prepared Direct Testimony of

Anita Hart

I. INTRODUCTION

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

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

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

A. My professional experience includes more than 25 years in the utility industry and I have a Master of Arts in Economics with an emphasis in Public Utility Regulation. I have worked for the Companies since 2008. In addition to my current role in Resource Planning and Analytics, I was the Manager of Gas Transportation Planning. I have also held Director and Consultant Staff positions in the Demand Side Management department at NV Energy.

Prior to joining the Companies, I was employed as the Manager of Demand Side Management and Market Research at Southwest Gas Corporation ("SWG"). Over a span of 15 years, my key responsibilities at SWG included: 1) resource planning and demand forecast modeling and analysis; 2) development and maintenance of tariffs, applications, and filings before three state regulatory agencies, consistent with regulatory, legal and company requirements; 3) development, approval, implementation and management of demand side management, or conservation and energy efficiency and low-income programs; and 4) market research. More details regarding my background and experience are provided in **Exhibit Hart-Direct-1.**

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

A. As Director of Resource Planning and Analysis, I am responsible for the development of the Companies' Integrated Resource Plans ("IRP") and IRP amendments, and Energy Supply Plans ("ESP"), ESP updates and Gas Information Reports. I oversee load forecasting, production cost modeling and economic analysis related to intermediate and long-term planning activities of the Companies.

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

A. Yes, I have testified in several proceedings before the Commission, in addition to the California Public Utilities Commission and the Arizona Corporation Commission. Most recently, I provided testimony before this Commission in Docket Nos. 20-07023, 20-09002, 20-12020 and 21-06001.

II. OVERVIEW AND TESTIMONY ORGANIZATION

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

A. I sponsor the economic analysis used in the evaluation of the resource plans in the First Amendment to 2021 Joint IRP 2022-2041 ("Amendment"). In Section III, I discuss actions that the Companies will take during the amended Action Plan period (2022-2024) to implement the projects in this Amendment. In Section IV, I discuss the economic analysis used in the selection of the Companies' Preferred Plan, a proposal that, if approved, will preserve their ability to provide safe, reliable electric service to customers at reasonable rates and increase their ability to reduce carbon emissions in Nevada.

Together with Dr. David Harrison, I support the Environmental and Externalities results contained in Technical Appendix ECON-9.

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

A. In addition to **Exhibit Hart-Direct-1**, I am sponsoring the following Technical Appendix Items:

- ECON-1: Notice of Public Meeting and Overview of the First Amendment
- ECON-2: Description of Production Cost Modeling Software
- ECON-3: Average Generation Costs - Redacted
- ECON-4: Energy Mix for All Cases
- ECON-5: Loads and Resources Tables
- ECON-6: Capital Projects (all cases and sensitivities)
- ECON-7: PWRR (Production Costs plus Capital Costs)
- ECON-8: PROMOD Area Diagram
- ECON-9: NERA Report

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

A. Yes. The following technical appendices are confidential:

- ECON-3: Average Generation Costs
- ECON-6: Capital Projects

8. Q. PLEASE EXPLAIN WHY ECON-3 AND ECON-6 ARE CONFIDENTIAL?

A. ECON-3 contains the average cost of energy from each of the Companies' generators. Costs specific to each generator are considered commercially-sensitive information. Disclosure of such information could put the Companies at a competitive disadvantage. ECON-6 contains sensitive projected capital cost information related to conventional placeholder resources. Public disclosure could harm the Companies' ability to negotiate the best priced contracts moving forward and would put the Companies at a competitive disadvantage.

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

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

10. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF THE REGULATORY OPERATIONS STAFF ("STAFF") OR THE BUREAU OF CONSUMER PROTECTION ("BCP") TO PARTICIPATE IN THIS DOCKET?

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

III. RESOURCE PLANNING AND THE ACTION PLAN

11. Q. PLEASE DESCRIBE THE AMENDMENT.

A. Less than a year ago, the Commission accepted the Companies' Preferred Plan in its 2021 Joint IRP ("2021 Preferred Plan"), which increased the operating flexibility of some of the Companies' existing generating facilities, aggressively added renewable resources to assist the state in meeting its carbon reduction goal by 2050 and provided new generation to replace the Valmy coal-fired station by 2025. What is driving the need for this amendment is the significant changes in the price and availability of market purchases required to close the open position, especially during peak summer month periods. As a result, the case development for this Amendment concentrated on reducing the Companies' open position with resources within its balancing area authority ("BAA"). The prepared direct testimony of Ryan Atkins describes the resource adequacy risks for the state of Nevada and the Western region as a whole that have manifested themselves since the summer of 2020, including the California Independent System Operator's ("CAISO") rule changes which have cast additional uncertainty into the market.

Economic analyses of different capacity and energy supply plans were conducted and a Preferred Plan was selected from the set of cases.

This filing continues the evolution of Nevada's energy industry and market, addressing emergent concerns about the uncertain availability of regional market capacity and the need to diversify energy storage to better integrate variable renewable resources.

12. Q. PLEASE DESCRIBE THE COMPANIES' RESOURCE NEEDS OVER THE INTEGRATED RESOURCE PLANNING HORIZON?

A. **Figure Hart-Direct-1** shows the 2021 Preferred Plan as approved in the 2021 Joint IRP. It shows the system capacity requirements (loads plus a planning reserve margin), the resources currently defined by the Companies (owned resources and those under contract), and placeholder resources. The base load forecast was used, and the resource capacities shown are those that can be counted on at the time of the system peak. That is, thermal units are shown at their peak capacities and renewable units have been adjusted for their effective load carrying capability ("ELCC").

Figure Hart-Direct-1

NV Energy Capacity Position As Approved In 2021 Joint IRP

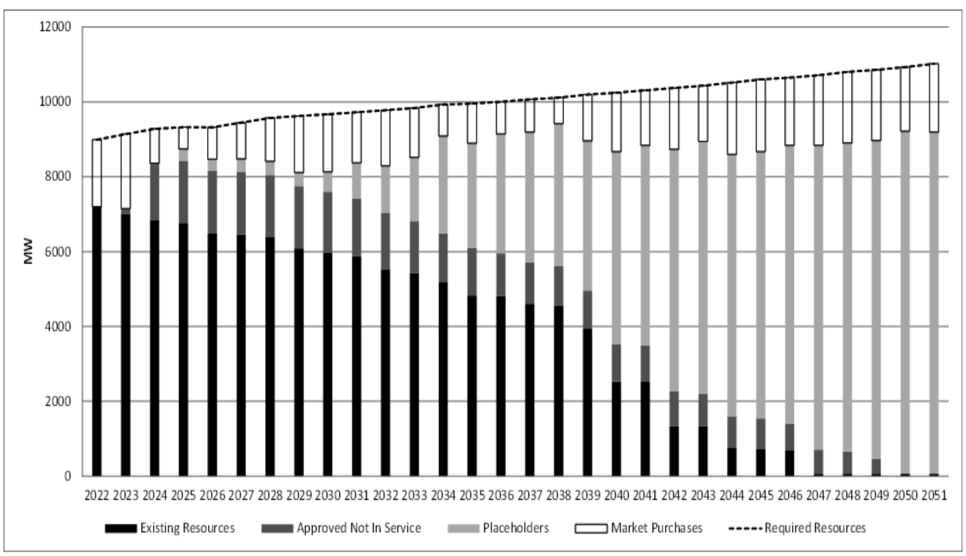


Figure Hart-Direct-1 also illustrates the expected steady increase in customer demand and the Companies' plan to meet the increased need with a combination of firm dispatchable resources, renewable resources and market purchases. The 2021

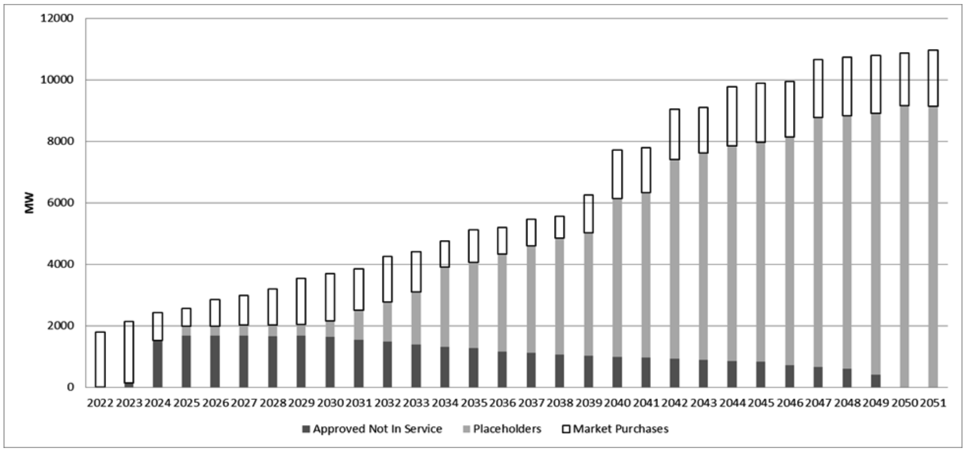
Preferred Plan assumed up to 2,000 MW of market capacity purchases would be available at a reasonable price during peak hours of the study period. Recent disruptions in typical peak market transactions, however, have caused the Companies to re-evaluate the acceptable level of market capacity purchases. The prepared direct testimony of Mr. Atkins describes the current state of the Western power markets.

Figure Hart-Direct-2 is a more in-depth view of the Companies' capacity position that removes the resources that are currently in operation. The figure shows the Companies have a significant reliance on market purchases for 2022-2023 and open capacity positions every year of the plan. The Preferred Plan presented in this Amendment includes projects that will assist in mitigating the reliance on market purchases both near-term and long-term.

Additionally, by 2025, the Companies achieve the illustrated open position by adding placeholder capacity, as shown in the figure. It is important to note the reduction in market purchases is also dependent on new resources meeting their projected commercial operation date ("COD"). Due to supply chain issues, there is added uncertainty that suppliers will be able to meet projected CODs. Shane Pritchard discusses in his prepared direct testimony some delays in projects the Companies have already experienced.

Figure Hart-Direct-2

Potential Uncertainty in NV Energy's Capacity Position



As discussed by Mr. Atkins, recent disruptions in power market availability and price stability led the Companies to look for additional capacity within the BAA. The additional capacity will serve the immediate need to reduce the near-term open position as well as help the Companies serve Nevada load with Nevada resources.

13. Q. PLEASE DESCRIBE ITEMS THAT THE COMPANIES ARE SEEKING APPROVAL OF IN THE AMENDMENT?

A. The Companies are requesting Commission approval of the following items:

- A new fuel and purchase power forecast;
- The addition of 66 megawatts ("MW") of upgrades to existing combustion turbines;
- A 220 MW grid-tied battery energy storage system ("BESS");
- A new 25 MW long-term power purchase agreement ("PPA") for the North Valley geothermal project; and
- Network upgrades for the BESS project.

Note that approval of the Sun Peak wet compression upgrade, evaluated as part of both the Preferred and Alternate Plans, is not being requested. Following the completion of the economic analysis, an opportunity arose to install the Sun Peak wet compression project prior to summer 2022. Early installation does not increase the cost of the project but does reduce the open position in 2022.

14. Q. PLEASE DESCRIBE THE RESOURCES MENTIONED ABOVE IN MORE DETAIL.

A. The Amendment seeks to amend the Generation plan with the addition of 66 MW of upgrades to existing combustion turbines ("CT"), specifically peak firing projects at the Chuck Lenzie Blocks 1 and 2, Harry Allen, and Tracy combined cycle units, and chilled water storage at Chuck Lenzie Blocks 1 and 2. The generation upgrade projects are discussed in the Generation Plan of the Supply Side narrative and sponsored by John Lescenski. In addition, the Companies propose to amend the Renewable Plan to add a Company-owned 220 MW grid-tied battery energy storage BESS and a new 25 MW PPA. The 220 MW BESS will be located at the previous site of the Reid Gardner Generating Station and has 440 MWh of storage capacity. The BESS is discussed in the Renewable Plan in the Supply Side narrative and sponsored by John Frankovich. The PPA is between Sierra and ORNI 36, LLC for the 25 MW North Valley geothermal generating facility located in Washoe County, Nevada. The North Valley PPA is the first geothermal PPA Sierra has requested approval of in more than a decade. The North Valley PPA is discussed in the Renewable Energy Plan of the Supply Side narrative and sponsored by Mr. Pritchard. Further, the Companies request to amend the Transmission plan to add infrastructure necessary for interconnection of the renewable projects discussed above. The transmission infrastructure upgrades are discussed in the Transmission section of the Supply Side narrative and sponsored by Charles Pottey.

IV. <u>RESOURCE PLANNING AND THE ACTION PLAN</u>

15. Q. PLEASE PROVIDE AN OVERVIEW OF KEY MODELING ASSUMPTIONS USED IN THE ECONOMIC ANALYSIS?

A. The economic analysis used the approved load forecast from the 2021 Joint IRP and addressed changes in federal carbon policy and its impact on fuel and purchase power prices, meets or exceeds the renewable portfolio standard in every year, achieves the state's 2050 clean energy goal, meets the 16 percent PRM for each utility and includes required reserves to be held for Open Access Transmission Tariff customers.

Supply-side resources include a combination of existing, proposed, and placeholder generation and PPA, both conventional and renewable. The capacity value assigned to supply-side resources represents the effective capacity of each resource during the peak load.

16. Q. PLEASE DESCRIBE THE CHANGES UTILIZED TO MODEL THE RENEWABLE ENERGY RESOURCES.

A. The Companies introduced a new resource in this analysis, the 2-hour BESS. The ELCC for the 2-hour BESS was assumed to be the same as for a 4-hour BESS. The Companies believe this is a reasonable assumption for a single installation. If additional 2-hour BESS were considered, however, a detailed analysis of the appropriate ELCC would be needed, as it would be expected to decline much faster than the ELCC of 4-hour BESS with increased penetration.

17. Q. PLEASE DESCRIBE THE BASE CASE USED IN THIS FILING.

A. The Base Case maintained the long-term resource buildout for each case as presented in the 2021 Preferred Plan approved in the 2021 Joint IRP. However, this case adds the wet compression projects on the Clark Peakers and Harry Allen peaking units to be completed before summer of 2022 as well as the power augmentation project on the Clark Mountain units to be completed by summer of 2023, all as described in the Generation narrative. The Base Case relies heavily on market capacity purchases – especially in the first few years of the study period.

18. Q. PLEASE DESCRIBE THE METHOD USED TO DEVELOP AND EVALUATE THE PLANS FOR THIS IRP AMENDMENT.

A. Each plan developed for this Amendment added incremental resources to the Base Case. By starting with the Base Case, each plan would meet the state's clean energy goals. By selecting incremental resources within the BAA that would be in commercial operation within a few years, the Companies will reduce their reliance on market capacity, thereby increasing the expected system reliability.

The Companies investigated a diverse set of incremental resources for this Amendment as described in detail in the Renewables and Generation narratives and in the testimony of Mr. Frankovich. The resources that progressed to the economic analysis are shown below.

Capacity upgrades to existing generating facilities

As defined in the Generation narrative, the following capacity upgrades were examined in the analysis:

- Wet compression at Sun Peak Units 3 through 5;

- Peak firing at the Chuck Lenzie Combined Cycle Blocks 1 and 2, Harry Allen Combined Cycle, and Tracy Combined Cycle; and
- Chilled water storage at Chuck Lenzie Combined Cycle Blocks 1 and 2.

<u>New combustion turbine generation</u>

A new 200 MW gas turbine, which is a firm dispatchable resource that can be in service by 2024, was examined. More information on this potential resource can be found in the Generation narrative.

<u>New geothermal PPA</u>

The 25 MW North Valley geothermal plant was modeled as a potential resource for Sierra. More information on this potential PPA can be found in the Renewables narrative.

<u>New stand-alone BESS</u>

2-hour and 4-hour stand-alone BESS were each evaluated. Details of the size and operational characteristics of the BESS can be found in the Renewables narrative.

The Companies grouped these candidates based on resource size (capacity) to create a series of screening analyses. The first screening analysis consisted of individual and combinations of generation fleet upgrades. Combinations of the best of the fleet upgrades and the new geothermal PPA were analyzed in the second screening. The Companies created a third screening analysis of the larger candidate resources – the combustion turbine, the 2-hour and the 4-hour BESS. The final screening analysis compared the present worth of individual and combinations of the best of the upgrades and geothermal PPA (second screen) and the best of the larger resources (third screen). The final alternative plans were selected from the last screening analysis. Detailed buildouts along with the results of the screening analysis may be found in the Economic Analysis section of the narrative. Load and Resources ("L&R") Tables for each of the screening cases analyzed are provided in Technical Appendix ECON-5.

19. Q. PLEASE DESCRIBE THE RESULTS OF THE SCREENING ANALYSES.

A. In the first screening analysis, each of the generation upgrades had the same or a lower present worth of revenue requirements ("PWRR") than the Base Case. The lowest PWRR from the first screening analysis was the case using all of the generator upgrades. It was also the case with the largest reduction in open position.

The second screening analysis compared the case with all the generator upgrades to a case with just the North Valley PPA, and to a case with both the upgrades and the PPA. Although not the lowest PWRR, the case with both the PPA and the upgrades was chosen as the best plan because it had the largest reduction in open position.

The third screening analysis determined the value of adding a 2-hour BESS, a 4-hour BESS, and a combustion turbine to the system. In this analysis, the case with the 2-hour BESS had the lowest PWRR but it did not have the largest reduction in open position. It was still selected as the best case because it reduced the amount of fossil units in the buildout.

The last screening looked at combinations of the previous analyses and the alternative plans were chosen from this analysis.

20. Q. PLEASE DESCRIBE THE ALTERNATIVE PLANS PRESENTED IN THIS FILING.

A. From the exhaustive series of screening analyses, the Companies selected the "All Generator Upgrades + North Valley PPA + 2-hr BESS," and the "All Generator Upgrades + North Valley PPA + CT" as the two alternative plans for the Amendment.

<u>All Generator Upgrades + North Valley + 2-hr BESS</u>: This plan combines all the generator upgrades, the North Valley PPA and the 220 MW-BESS. As a result of these additions, the firm dispatchable placeholder added in 2034 is reduced to 180 MW.

<u>All Generator Upgrades + North Valley + CT</u>: This plan combines all the generator upgrades, the North Valley PPA and a 200 MW combustion turbine. Similarly, the firm dispatchable placeholder added in 2034 is reduced to 180 MW as a result of this plan.

The full resource buildout for the Base Case and alternative plans are shown in **Figure Hart-Direct-3**. The Companies do not recommend continuing with the Base Case. It has been provided here to illustrate the differences in the alternative cases.

Hart-Direct-3

Resource Buildout For Base And Alternative Cases

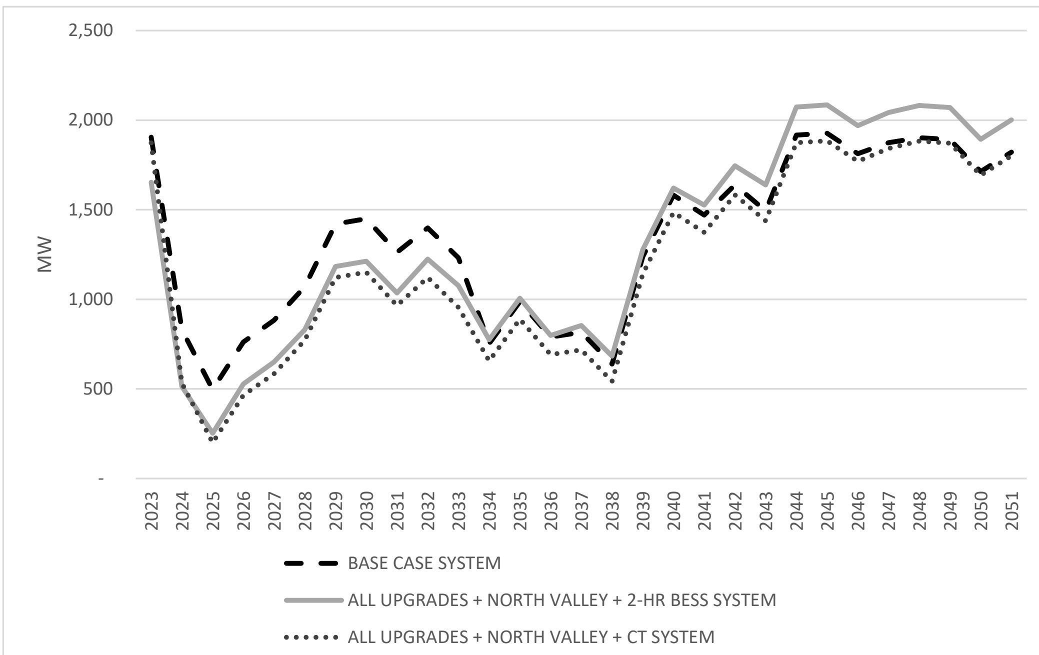
	BASE CASE		2-hr BESS		CT	
	Sierra	Nevada Power	Sierra	Nevada Power	Sierra	Nevada Power
2023			North Valley Geo	Sun Peak wet compression 2-hr BESS	North Valley Geo	Sun Peak wet compression
2024			Tracy Peak fire	Lenzie & HA peak fire Lenzie cold storage	Tracy Peak fire	Lenzie & HA peak fire Lenzie cold storage Silverhawk CT
2025		350 MW PV - paired_25 276 MW BESS - paired_25		350 MW PV - paired_25 276 MW BESS - paired_25		350 MW PV - paired_25 276 MW BESS - paired_25
2026						
2027		229 MW PV - alone_27		229 MW PV - alone_27		229 MW PV - alone_27
2028		75 MW PV - alone_28		75 MW PV - alone_28		75 MW PV - alone_28
2034	168 MW Firm_NN_34	360 MW Firm_SN_34 561 MW BESS - paired_34 561 MW PV - paired_34	168 MW Firm_NN_34	180 MW Firm_SN_34 561 MW BESS - paired_34 561 MW PV - paired_34	168 MW Firm_NN_34	180 MW Firm_SN_34 561 MW BESS - paired_34 561 MW PV - paired_34
2035		309 MW BESS - paired_35 309 MW PV - paired_35		309 MW BESS - paired_35 309 MW PV - paired_35		309 MW BESS - paired_35 309 MW PV - paired_35
2036	304 MW BESS - paired_36 304 MW PV - paired_36	305 MW BESS - paired_36 305 MW PV - paired_36	304 MW BESS - paired_36 304 MW PV - paired_36	305 MW BESS - paired_36 305 MW PV - paired_36	304 MW BESS - paired_36 304 MW PV - paired_36	305 MW BESS - paired_36 305 MW PV - paired_36
2037		512 MW BESS - paired_37 512 MW PV - paired_37		512 MW BESS - paired_37 512 MW PV - paired_37		512 MW BESS - paired_37 512 MW PV - paired_37
2038		630 MW BESS - paired_38 630 MW PV - paired_38		630 MW BESS - paired_38 630 MW PV - paired_38		630 MW BESS - paired_38 630 MW PV - paired_38
2039	86 MW BESS - alone_39	361 MW BESS - paired_39 361 MW PV - paired_39	86 MW BESS - alone_39	361 MW BESS - paired_39 361 MW PV - paired_39	86 MW BESS - alone_39	361 MW BESS - paired_39 361 MW PV - paired_39
2040	100 MW BESS - alone_40	476 MW BESS - paired_40 476 MW PV - paired_40 900 MW Firm_SN_40	100 MW BESS - alone_40	476 MW BESS - paired_40 476 MW PV - paired_40 900 MW Firm_SN_40	100 MW BESS - alone_40	476 MW BESS - paired_40 476 MW PV - paired_40 900 MW Firm_SN_40
2041	69 MW BESS - alone_41	394 MW BESS - paired_41 394 MW PV - paired_41	69 MW BESS - alone_41	394 MW BESS - paired_41 394 MW PV - paired_41	69 MW BESS - alone_41	394 MW BESS - paired_41 394 MW PV - paired_41
2042	313 MW BESS - alone_42	349 MW BESS - paired_42 349 MW PV - paired_42 900 MW Firm_SN_42	313 MW BESS - alone_42	349 MW BESS - paired_42 349 MW PV - paired_42 900 MW Firm_SN_42	313 MW BESS - alone_42	349 MW BESS - paired_42 349 MW PV - paired_42 900 MW Firm_SN_42
2043	453 MW BESS - alone_43	423 MW BESS - paired_43 423 MW PV - paired_43	453 MW BESS - alone_43	423 MW BESS - paired_43 423 MW PV - paired_43	453 MW BESS - alone_43	423 MW BESS - paired_43 423 MW PV - paired_43
2044		736 MW BESS - paired_44 736 MW PV - paired_44		736 MW BESS - paired_44 736 MW PV - paired_44		736 MW BESS - paired_44 736 MW PV - paired_44
2045	450 MW BESS - paired_45 450 MW PV - paired_45		450 MW BESS - paired_45 450 MW PV - paired_45		450 MW BESS - paired_45 450 MW PV - paired_45	
2046	25 MW BESS - paired_46 25 MW PV - paired_46	751 MW BESS - paired_46 751 MW PV - paired_46	25 MW BESS - paired_46 25 MW PV - paired_46	751 MW BESS - paired_46 751 MW PV - paired_46	25 MW BESS - paired_46 25 MW PV - paired_46	751 MW BESS - paired_46 751 MW PV - paired_46
2047	1705 MW BESS - paired_47 1705 MW PV - paired_47	585 MW BESS - paired_47 670 MW PV - paired_47	1705 MW BESS - paired_47 1705 MW PV - paired_47	585 MW BESS - paired_47 670 MW PV - paired_47	1705 MW BESS - paired_47 1705 MW PV - paired_47	585 MW BESS - paired_47 670 MW PV - paired_47
2048	124 MW BESS - paired_48 124 MW PV - paired_48	185 MW BESS - paired_48 185 MW PV - paired_48	124 MW BESS - paired_48 124 MW PV - paired_48	185 MW BESS - paired_48 185 MW PV - paired_48	124 MW BESS - paired_48 124 MW PV - paired_48	185 MW BESS - paired_48 185 MW PV - paired_48
2049	593 MW BESS - paired_49 593 MW PV - paired_49	70 MW BESS - paired_49 70 MW PV - paired_49	593 MW BESS - paired_49 593 MW PV - paired_49	70 MW BESS - paired_49 70 MW PV - paired_49	593 MW BESS - paired_49 593 MW PV - paired_49	70 MW BESS - paired_49 70 MW PV - paired_49
2050		2323 MW BESS - paired_50 2323 MW PV - paired_50		2323 MW BESS - paired_50 2323 MW PV - paired_50		2323 MW BESS - paired_50 2323 MW PV - paired_50

21. Q. PLEASE PROVIDE AN OVERVIEW OF THE OPEN CAPACITY POSITIONS FOR THE BASE CASE AND ALTERNATIVE PLANS?

A. As illustrated in **Figure Hart-Direct-4**, the open capacity positions for both alternative plans are greatly reduced compared to the Base Case for the next decade.

Hart-Direct-4

Open Positions for Each Plan (Base Load)



22. Q. DID THE COMPANIES' CONDUCT SCENARIO ANALYSIS OF ANY KEY ASSUMPTIONS?

A. Yes. The base fuel and purchase power price forecasts have been supplemented with additional fuel and purchase power price forecasts: high and low fuel and purchase power price forecasts. The mid-level carbon price assumption has been tested with three additional forecasts: high, low, and no carbon price sensitivities.

23. Q. **WHAT WERE THE RESULTS OF THE FINAL ECONOMIC ANALYSES?**

A. The results of sensitivity analyses are presented in **Figures Hart-Direct-5** and **Hart-Direct-6**, which present the PWRR for fuel and purchase power price and carbon sensitivities over 20 and 30 years, respectively. A discussion of key findings follows the figures.

Figure Hart-Direct-5

20-Year PWRR for All Plans and Sensitivities

20-year PWRR ($ millions) by Scenario						
	Base Load					
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC
all + North Valley + 2-hr BESS	$ 20,333	$ 19,500	$ 20,788	$ 19,884	$ 25,444	$ 17,675
all + N Valley + CT	$ 20,395	$ 19,551	$ 20,858	$ 19,944	$ 25,541	$ 17,719

20-year PWRR Differential ($ millions) by Scenario						
	Base Load					
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC
all + North Valley + 2-hr BESS	$ -	$ -	$ -	$ -	$ -	$ -
all + N Valley + CT	$ 62	$ 52	$ 70	$ 59	$ 97	$ 45

20-year PWRR Ranking by Scenario						
	Base Load					
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC
all + North Valley + 2-hr BESS	1	1	1	1	1	1
all + N Valley + CT	2	2	2	2	2	2

FIGURE Hart-Direct-6

30-Year PWRR for All Plans and Sensitivities

30-year PWRR ($ millions) by Scenario						
	Base Load					
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC
all + North Valley + 2-hr BESS	$ 27,745	$ 26,202	$ 28,508	$ 27,010	$ 34,957	$ 24,350
all + N Valley + CT	$ 27,800	$ 26,246	$ 28,570	$ 27,062	$ 35,072	$ 24,387

30-year PWRR Differential ($ millions) by Scenario						
	Base Load					
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC
all + North Valley + 2-hr BESS	$ -	$ -	$ -	$ -	$ -	$ -
all + N Valley + CT	$ 55	$ 44	$ 63	$ 52	$ 115	$ 37

30-year PWRR Ranking by Scenario						
	Base Load					
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC
all + North Valley + 2-hr BESS	1	1	1	1	1	1
all + N Valley + CT	2	2	2	2	2	2

The key findings of the 20-year and 30-year PWRR analysis are summarized below.

- The "All Generator Upgrades + North Valley + 2-hr BESS" case has the lowest 20-yr and 30-yr PWRR for all fuel, market and carbon price scenarios.
- The "All Generator Upgrades + North Valley + 2-hr BESS" case has less excess energy than the "All Generator Upgrades + North Valley + CT" case.

The production costs, capital costs, and total PWRR results for all the scenarios are found in Technical Appendix items ECON-6 and ECON-7.

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

24. Q. IN ADDITION TO THE INTERNAL ECONOMIC ANALYSIS, DID THE COMPANIES RELY ON OTHER ANALYSIS FROM OUTSIDE EXPERTS TO EVALUATE THE VARIOUS CASES AND CHOOSE A PREFERRED PLAN?

A. Yes. The Companies retained the services of NERA.

25. Q. PLEASE DESCRIBE THE ANALYSIS CONDUCTED BY NERA.

A. NERA conducted the present worth of societal costs ("PWSC") analysis for the alternative cases. The PWSC of a resource case is defined as the sum of the PWRR plus "environmental costs that are not internalized as private costs to the utility…."[1] Environmental costs are defined by the Commission as "costs, wherever they may occur, that result from harm or risks of harm to the environment after the application of all mitigation measures required by existing environmental regulation or otherwise included in the resource plan."[2] In addition, environmental costs to the state associated with operating and maintaining a supply plan or demand-side plan must be quantified for air emissions, water and land use and the social cost of the plan.

The regulations also require the Companies to assess the "net economic benefits" of cases under certain circumstances, as noted below.[3] "Economic benefits" are often referred to as "economic impacts," so that they are distinguished from other types of benefits. The net economic benefits include both the positive impacts of greater expenditures in Nevada and the negative impacts of higher electricity rates for consumers and businesses that generally accompany greater expenditures.

[1] Nevada Administrative Code ("NAC") Section 704.937, subsection 4.
[2] NAC 704.9359.
[3] *See* NAC 704.9357.

NERA provided analyses of the environmental costs and net economic benefits for the two alternative plans. Details on NERA's analyses of the two plans are provided in the NERA report (Technical Appendix Item ECON-9) and are sponsored by Dr. Harrison.

26. Q. PLEASE SUMMARIZE THE FINAL PREFERRED PLAN AND THE CRITERIA USED IN MAKING THAT DECISION.

A. The following criteria was used when selecting the "All Generator Upgrades+ North Valley + 2-Hr BESS" plan as the Preferred Plan and the "All Generator Upgrades + North Valley + CT" plan as the Alternate Plan.

1. The Companies' intent to reduce the risk of exposure to the uncertain availability of market capacity

As described in the introduction to this Amendment, recent events and reports contribute to decreasing confidence in the availability of market capacity. While the 2021 Joint IRP reduced the reliance on market capacity relative to prior plans, there is concern that further reduction is required to reduce risk and ensure resource adequacy. This Amendment takes advantage of all that has been set in motion and further addresses increasing concerns regarding the availability of market capacity as it is impacted by changes in climate, weather, and resource variability across the region. While both plans proposed in this Amendment take great efforts to reduce the near term exposure to market capacity, the "All Generator Upgrades + North Valley + 2-Hr BESS" plan is able to achieve a greater reduction sooner, due to the earlier in-service date of the 2-Hour BESS relative to the Silverhawk CT.

2. PWRR and PWSC results

While the costs of the two plans proposed in this Amendment are not too dissimilar, the "All Generator Upgrades + North Valley + 2-Hr BESS" plan has a lower PWRR and PWSC than the "All Generator Upgrades + North Valley + CT" plan.

3. The Companies' and the state's decarbonization goals

While both plans presented in this Amendment add a diverse renewable resource in the form of the North Valley geothermal project and achieve the state's 2050 clean energy goal, the "All Generator Upgrades + North Valley + 2-Hr BESS" plan moves the decarbonizing needle further sooner and increases diversity in the form of a 2-hour BESS project.

While the "All Generator Ugrades + North Valley + CT" plan benefits from the stable capacity of the Silverhawk CT project rather than the declining ELCC of the 2-Hour BESS project, it is a higher cost plan and does not advance decarbonization objectives in the same manner. The Companies continue to investigate emerging technologies that advance decarbonization objectives that will allow turbines to operate on hydrogen or other potential clean fuels. As these technologies develop, the Companies will consider the economics and explore their feasibility in future filings. Ultimately, early reduction of the open position, cost, and consistency with decarbonizing goals led the Companies to select the "All Generator Upgrades + North Valley + 2-Hr BESS" Plan as the Preferred Plan when balancing the objectives listed above.

27. Q. WHY DID THE COMPANIES INCLUDE A NEW FOSSIL UNIT IN THE ALTERNATE PLAN?

A. Consistent with NAC Chapter 704, the Companies' amended supply plan contains a diverse set of alternative plans.[4] As described throughout this filing, the Companies' focus on this Amendment was to evaluate all plausible resources to quickly reduce the open capacity positions due to the uncertain availability and deliverability of market capacity and energy. The generation upgrades and geothermal resource will all be implemented in short order, but are limited in the amount of open capacity reductions they will provide. The 2-hour BESS and CT are diverse solutions, and both provide at least 200 MW of capacity in the next few years.

The Companies are requesting approval of the Preferred Plan with the 2-hour BESS instead of the CT as it is more financially prudent and aligns with the clean energy goals of the Companies and the State of Nevada. The Alternate Plan, which includes a new CT, provides a diverse supply-side option for consideration.

28. Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. It is important to note that the Amendment is not driven by a single planning need. Resource planning decisions are not binary and must be designed to balance multiple objectives in a prudent and practical manner. The obligations incorporated into the Preferred Plan enhance reliability, reduce risk, improve price stability through fixed pricing, increase the diversity of the Companies' supply-side portfolio and meet the state's goals and policies.

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[4] *See* NAC 704.937.

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

A. Yes.

STATEMENT OF QUALIFICATIONS

ANITA L. HART
NEVADA POWER COMPANY d/b/a NV Energy
SIERRA PACIFIC POWER COMPANIES d/b/a NV Energy
6226 W. Sahara Ave.
Las Vegas Nevada 89146
(702) 402-2165

EDUCATION

NEW MEXICO STATE UNIVERSITY – Las Cruces, New Mexico
Master of Art in Economics – Emphasis in Public Utilities and Regulatory Economics
Bachelor of Art in Economics

PROFESSIONAL EXPERIENCE

NV ENERGY – Las Vegas, Nevada (August 2008 to Present)

Director – Resource Planning and Analysis

- Oversight of the Resource Planning and Analysis team
- Development of the Companies' Integrated Resource Plans ("IRP") and IRP amendments, and Energy Supply Plans ("ESP"), ESP updates and Gas Information Reports.
- Oversite of load forecasting, production cost modeling and economic analysis related to intermediate and long-term planning activities of the Companies.

Director – Demand Side Management, Energy Efficiency/Conservation

- Oversight of the Demand Side Management team
- Development and implementation, analysis and cost recovery of cost-effective statewide demand side management programs.

Manager – Gas Transportation Planning, Resource Planning and Analysis

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

Consultant Staff – DSM Planning, Customer Strategy & Programs

- Team member assisting in the development and implementation, analysis and cost recovery of statewide demand side management programs.

<u>SOUTHWEST GAS CORPORATION – LAS Vegas, Nevada (1993 to 2008)</u>

Manager – State Regulatory Affairs/Research, Conservation and DSM

- Oversight of the Demand Side Management team
- Development, implementation, evaluation and reporting of DSM and low income assistance programs in the Southwest Gas Corporation's tristate service territories.
- Directed the development and implementation of customer market research.

Senior Specialist – State Regulatory Affairs

- Prepared and maintained tariffs, applications, and filings before three state regulatory agencies, consistent with regulatory, legal and company requirements.

Administrator and Specialist – Marketing/Conservation and DSM

- Team member assisting in the development, implementation, evaluation and reporting of DSM and low income assistance programs in the Southwest Gas Corporation's tristate service territories.

Regulatory Analyst – Revenue Requirements and Resource Planning

- Collection, maintenance and statistical analysis of customer profile data.

<u>PUBLIC SERVICE COMPANY OF NEW MEXICO – ALBUQUERQUE, New Mexico (Summer 1992)</u>

Student Intern – Regulation and Market Communication

- Completion of a retail wheeling study.

BOARDS AND HONORS

<u>SOUTHWEST ENERGY EFFICIENCY PROJECT ("SWEEP")</u>

- 2016-2019 Board of Directors, Member

<u>LAS VEGAS METRO CHAMBER OF COMMERCE FOUNDATION</u>

- 2015 Leadership Las Vegas, Graduate

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, ANITA HART, states that she is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of her knowledge and belief; and that if asked the questions appearing therein, her answers thereto would, under oath, be the same.

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

Date: March 18, 2022

Anita Hart

ANITA HART

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

KIMBERLY HOPPS

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

First Amendment to the
2021 Joint Triennial Integrated Resource Plan (2022-2041)
Docket No. 22-03___

Prepared Direct Testimony of

Kimberly Hopps

I. INTRODUCTION

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

A. My name is Kimberly Hopps. My current position is Assistant Treasurer for Sierra Pacific Power Company d/b/a NV Energy ("Sierra") and Nevada Power Company d/b/a/ NV Energy ("Nevada Power" and, together with Sierra, the "Companies"). My business address is 6226 West Sahara Avenue in Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

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

A. I have been employed by the Companies since February 2004 and was named Assistant Treasurer in April 2020. My prior experience includes various financial and operational analysis roles including serving as the Business Performance Director in the Business Optimization and Innovation department, where I was responsible for benchmarking, collaborating with other Berkshire Hathaway Energy Company platforms and process improvements. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Hopps-Direct-1**.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS ASSISTANT TREASURER.

A. My responsibilities include aspects of treasury, financial planning and risk control. In the treasury and treasury planning capacity, I am responsible for management and oversight of the Companies' day-to-day cash positions as well as short- and long-term financial planning particularly as it relates to cash, debt, and capital structure. I oversee the Companies' financing activities to ensure compliance with company policies, debt covenants, and Public Utilities Commission of Nevada ("Commission") orders. I am responsible for monitoring and managing the Companies' credit ratings, several Sarbanes-Oxley controls relating to finance, treasury, risk control (including the setting of counterparty credit limitations, monitoring of fuel and purchase power transactions and verification of recorded trade data that is used for settlements) and other financial and risk related functions.

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

A. Yes. I have provided testimony in the energy supply plans ("ESP") and ESP updates and the deferred energy proceedings for the Companies since 2020, the most recent being the 2022 deferred energy proceedings for Nevada Power, Docket No. 22-03001, and Sierra, electric and natural gas, Docket Nos. 22-03002 and 22-03003, respectively.

II. OVERVIEW AND TESTIMONY ORGANIZATION

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

A. I sponsor the Financial Plan in the Supply Side Plan narrative to the First Amendment to the 2021 Joint Integrated Resource Plan ("Amendment"). In Section

III of my direct testimony, I provide an overview of the Preferred and Alternate plans' capital commitments and associated financial impacts. Section IV of my direct testimony provides a more detailed discussion of the Companies' financial plans associated with the Preferred and Alternate plans, including capital spending projections, funding requirements, credit metric impacts, and customer rate impacts. My direct testimony and the Financial Plan address the impacts of the Preferred and Alternate plans from the customer perspective and reflect traditional rate making principles.

6. Q. WHAT EXHIBITS ARE YOU SPONSORING?

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

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

A. Yes. There are multiple figures in the Financial Plan of the Supply Side Plan narrative that are confidential. Specifically, Figures FP-3 and FP-4 in the External Financing Requirements section of the Financial Plan and Figures FP-11 through FP-18 in the Credit Quality section of the Financial Plan should be treated as confidential.

8. Q. PLEASE EXPLAIN WHY THIS INFORMATION SHOULD BE TREATED AS CONFIDENTIAL.

A. Sierra and Nevada Power's debt is publicly traded. The information identified in Q&A 7 has not been previously disclosed to the public. Public disclosure of this information could influence fixed income investors' view of the underlying credit quality of, and debt pricing for, the Companies.

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

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

10. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF THE COMMISSION'S REGULATORY OPERATIONS STAFF ("STAFF") OR THE NEVADA ATTORNEY GENERAL'S BUREAU OF CONSUMER PROTECTION ("BCP") TO FULLY INVESTIGATE THE 2021 JOINT IRP?

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

III. PREFERRED AND ALTERNATE PLANS

11. Q. PLEASE PROVIDE AN OVERVIEW OF THE PREFERRED AND ALTERNATE PLANS' CAPITAL REQUIREMENTS AND FINANCIAL IMPACTS.

A. The capital requirements of the Preferred Plan total $10,657.5 million and $5,182.1 million (including Allowance for Funds Used During Construction ("AFUDC")) for Nevada Power and Sierra, respectively. The capital expenditures (including AFUDC) of the Preferred and Alternate plans are shown below in **Figure Hopps-Direct-1** for Sierra and **Figure Hopps-Direct-2** for Nevada Power. These figures were constructed using the capital expense recovery ("CER") model. For Sierra, capital expenditures for the 2023-2042 period total approximately $5,182.1 million for the Preferred and Alternate plans. This amount includes $271.6 million of incremental capital that is being requested in this filing. Over the next five years, the incremental capital requested in this filing for the Preferred and Alternate plans is only $24.4 million. For Nevada Power, capital expenditures over the same period total $10,657.5 million and $10,782.0 million for the Preferred and Alternate plans, respectively. These projections include $2,792.8 million and $2,906.0 million for the Preferred and Alternate plans, respectively, of incremental capital over the 2023-2042 period. Over the next five years, Nevada Power's incremental capital for the Preferred and Alternate plans is estimated to be $168.9 million and $282.1 million, respectively.

FIGURE HOPPS-DIRECT-1
SIERRA
CAPITAL EXPENDITURES ($ - MILLIONS)

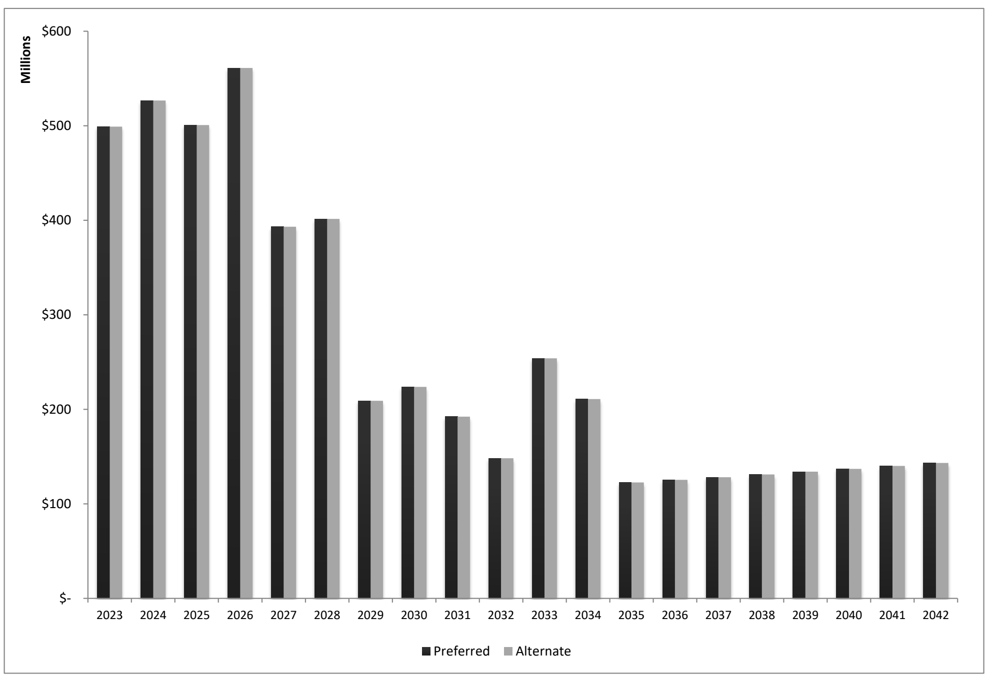
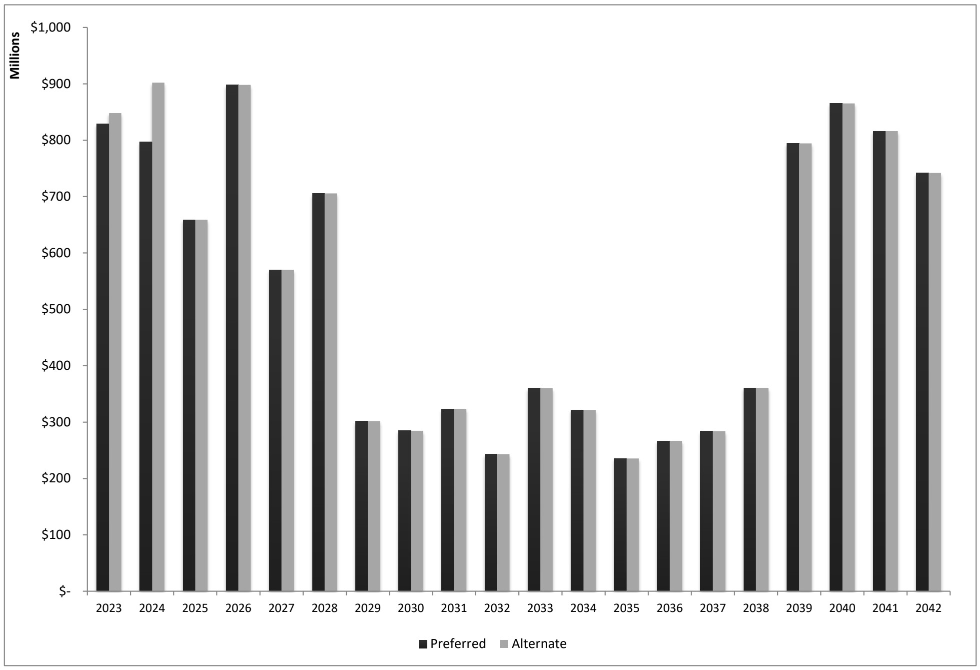


FIGURE HOPPS-DIRECT-2
NEVADA POWER
CAPITAL EXPENDITURES ($ - MILLIONS)



IV. <u>FINANCIAL IMPACTS TO SIERRA AND NEVADA POWER</u>

12. Q. HOW WOULD THE COMPANIES FINANCE THE PREFERRED PLAN OR ALTERNATE PLAN?

A. For both utilities, cash generated from internal operations during the 2023-2042 period is projected in total to exceed the capital projects set forth in the CER models for the Preferred and Alternate plans. Common equity and debt funding will be balanced to support the Companies' credit ratings and capital structures reasonable for ratemaking purposes. Common equity funding will come through internally generated funds, the curtailment of dividends, and, if necessary, the issuance of common equity. The Companies will, however, have a continued need to access external financing to fund the capital projects and to refinance maturing debt. Figures FP-3 and FP-4 in the Financial Plan show annual total external financing over the forecast horizon for the Preferred and Alternate plans for Nevada Power and Sierra, respectively. The external financing projections shown in these two figures reflect both incremental financing requirements for the Companies' projected total capital spending and refinancing of debt maturities.

13. Q. WILL THE COMPANIES BE ABLE TO ACCESS THE CAPITAL MARKETS IN ORDER TO FINANCE THE PREFERRED OR ALTERNATE PLANS, IF NEEDED?

A. Yes. Both utilities have maintained adequate liquidity and demonstrated the ability to successfully access the debt markets at competitive rates relative to industry peers. Maintaining access to external capital at favorable rates is critical in order to minimize customer rates. To the best of their abilities, both utilities will manage their capital structures in a way that mitigates any potential negative pressure on credit quality from the Preferred Plan. However, capital expenditure levels at Sierra may result in credit metric challenges. Regulatory support is essential to ensure continued access to the debt and equity capital necessary to serve customers at just and reasonable rates. Over-reliance on the debt markets to fund future investments could lead to credit quality weakening and excessive financing costs. Regulatory support is necessary to attract equity capital, maintain a balanced capital structure, and prevent a deterioration in credit metrics.

The relatively small amount of incremental capital for which the Companies are seeking approval in this filing is not expected to have a material impact on the credit quality or credit metrics of either company. Although Sierra's credit metrics have weakened recently, the $24.4 million of incremental capital expenditures over the next five years requested in this filing for the Preferred and Alternate plans is not expected to have a material negative impact on Sierra's credit metrics. NV Energy remains focused on Sierra's credit situation and will address the company's credit ratings and any associated mitigation recommendations in its June 2022 general rate case. From a credit perspective, Nevada Power is currently in a better position relative to Sierra and is not expected to be negatively impacted by the incremental capital sought in this filing.

14. Q. ARE YOU RECOMMENDING ANY ADJUSTMENTS IN THIS FILING TO ADDRESS THE IMPACT THAT THE NORTH VALLEY POWER PUCHASE AGREEMENT ("PPA") WILL HAVE ON SIERRA'S IMPUTED DEBT?

A. No. While Nevada Administrative Code 704.88875 allows for a discussion of strategies to mitigate the debt imputation performed by the rating agencies for PPAs, the Companies are not proposing any imputed debt mitigation of the North Valley geothermal facility PPA in this filing. The Companies have historically addressed the impact PPAs have on the Companies' imputed debt and credit metrics during the general rate case process. The North Valley PPA presented for approval in this filing is for 25 megawatts and its impact on Sierra's imputed debt will be addressed in Sierra's general rate case proceedings, as part of the overall effect PPAs have on Sierra's imputed debt.

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

A. Yes, it does.

KIMBERLY HOPPS
ASSISTANT TREASURER
NV Energy
6226 West Sahara Avenue
Las Vegas, NV 89151
(702) 402-5622

SUMMARY

Kimberly Hopps has been with NV Energy since February 2004, and has approximately 20 years of experience in accounting, finance and operational performance management experience.

At NV Energy, Ms. Hopps has primary responsibility for treasury and risk control activities.

EMPLOYMENT

NV Energy

- Assistant Treasurer, Las Vegas NV (10 months)
- Business Performance Director, Las Vegas NV (2 years)
- Generation Business Manager, Las Vegas NV (5 years)
- Manager, Financial Planning & Analysis, Las Vegas NV (4 years)
- Senior Business Analyst, Reno NV (2 years)
- Business Analyst, Tuscarora Gas Transmission, Reno NV (3 years)

Washoe Tribe of Nevada & California – Accountant, Gardnerville NV (1 year)

Concrete Systems – Full Charge Bookkeeper, Las Vegas NV (3 years)

EDUCATION

Masters of Business Administration (University of Phoenix, Las Vegas NV)
Bachelor of Arts – Political Science / Communication (University of Arizona, Tucson AZ)

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, KIMBERLY HOPPS, states that she is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of her knowledge and belief; and that if asked the questions appearing therein, her answers thereto would, under oath, be the same.

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

Date: March 18, 2022

KIMBERLY HOPPS

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

JOHN LESCENSKI

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

First Amendment to the
2021 Joint Triennial Integrated Resource Plan (2022-2041)
Docket No. 22-03___

Prepared Direct Testimony of

John Lescenski

INTRODUCTION AND BACKGROUND

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

A. My name is John Lescenski. My current position is Manager, Generation Engineering and Technical Services for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company ("Sierra" and, together with Nevada Power, the "Companies"). My business address is 6226 West Sahara Avenue, Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

2. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS MANAGER, GENERATION ENGINEERING AND TECHNICAL SERVICES.

A. As Manager, Generation Engineering and Technical Services, I am responsible for generation fleet-wide asset strategy development, regulatory planning and analysis, technical support for new solar resource contracts and technical support to the Companies' generation fleet.

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

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

A. Yes. I provided written testimony in past Companies filings for deferred energy, integrated resource planning and general rate cases, including most recently in Docket Nos. 13-07005, 13-06002 and 13-06004.

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

A. I support the Generation section in the Supply Side Plan amendment narrative. In Section II below, I discuss the wet compression upgrade projects and the Companies' requests for approval of generation investments to install peak firing projects on the combined cycle units at the Tracy, Chuck Lenzie, and Harry Allen Generating Stations as well as chilled water storage at the Chuck Lenzie Generating Station. In Section III below, I discuss the Silverhawk Peaking Plant, for informational purposes only.

5. Q. ARE YOU SPONSORING ANY EXHIBITS AND TECHNICAL APPENDICIES?

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

- Exhibit Lescenski-Direct-1 Statement of Qualifications
- GEN-1 - Unit Characteristics Table (Confidential)
- GEN-2 - New Generation Unit Performance Data (Confidential)

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

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

A. Yes. GEN-1 contains confidential cost and performance data. GEN-2 includes confidential information regarding the Companies' estimated performance of potential future resources. These confidential technical appendices contain commercially sensitive and/or trade secret information that derive independent economic value from not being generally known. This information discloses the Companies' views and expectations of the relevant markets and its future procurement opportunities. This information is not known outside the Companies and its distribution is limited within the Companies. Releasing this highly sensitive information would disadvantage the Companies and their customers by limiting their ability to foster competition among prospective suppliers, compromising the Companies' negotiating position and reducing bargaining leverage. Publication of this information would unfairly advantage competing suppliers and impair the Companies' ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of its customers.

7. Q. FOR HOW LONG DOES NEVADA POWER REQUEST CONFIDENTIAL TREATMENT?

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

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

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

CAPACITY INCREASE PROJECTS

9. Q. PLEASE DESCRIBE THE PROPOSED CAPACITY INCREASE PROJECT FOR THE SUN PEAK GENERATING UNITS THAT IS INCLUDED IN THE PREFERRED PLAN.

A. The Companies were initially requesting approval to add wet compression to the Sun Peak generating units in the Preferred Plan. This project is similar to the wet compression system that was added to the Walt Higgins units and was approved for the Silverhawk Combined Cycle ("CC") combustion turbine units in Docket No. 21-06001. This system injects water ahead of the compressor section of the combustion turbine, which increases the density of the air used for combustion and allows each turbine to provide additional capacity. The wet compression system on each turbine is intended to be used for up to 300 hours per year, during high peak periods. The turbine will remain available for normal operation (i.e. running without the use of wet compression) the remainder of the time. The limited hours for operating with wet compression are due to additional maintenance and inspections that are required after the unit is operated with wet compression.

10. Q. WHY WERE THE COMPANIES ONLY REQUESTING WET COMPRESSION ON THE SUN PEAK UNITS AND NOT ON THE COMPANIES' OTHER SIMPLE CYCLE UNITS IN THE PREFERRED CASE?

A. The Companies are pursuing wet compression upgrades on most of its simple cycle peaking units, with many of the units planned to receive the wet compression upgrades prior to the 2022 summer peak season. At the time this filing was being modeled and completed, the Sun Peak units were believed to require additional time to modify the air permit's current heat input limits based on the current design capability of the existing units. However, since that time, the Companies identified an option to install the wet compression on the Sun Peak units prior to the summer 2022 and continue to operate under the existing permit heat input requirements. This option will provide additional capacity during the summer 2022 peak but based on ambient conditions and permit heat input limits, may not allow full utilization of the units' capability with or without wet compression operation. The Companies are continuing to pursue heat input limit increases on the Sun Peak units that will allow full utilization of the unit capability with and without wet compression and this permitting is not expected to be completed until Summer 2023. However, due to the opportunity to install the wet compression system to be available for the summer 2022 peak, the Companies are not requesting Commission approval of the Sun Peak wet compression upgrades as part of the

Preferred Plan, even though they are included in the Preferred Plan economic analysis.

11. Q. WHAT ARE THE EXPECTED COSTS AND PERFORMANCE OF THE SIMPLE CYCLE UPGRADE PROJECTS?

A. The expected costs and performance are listed in **Table Lescenski Direct - 1**.

TABLE LESCENSKI DIRECT - 1

SIMPLE CYCLE WET COMPRESSION UPGRADES

Plant	Expected Capacity Upgrade at Peak	Expected Project Cost	Upgrade Inservice Date
Sun Peak 3,4,5	21 MW	$8,600,000	May 31, 2023
Harry Allen 3,4	14 MW	$7,500,000	May 31, 2022
Clark Peaking Plant	60 MW	$19,000,000	May 31, 2022
Clark Mt. 3,4	14 MW	N/A	May 31, 2023

The Clark Mountain units do not have a projected project cost since they have a power augmentation system that was commissioned but requires a permit modification to allow for additional startup/shut-down emissions. The Companies are pursuing permit modifications to allow this peak operation.

12. Q. PLEASE EXPLAIN WHY THE COMPANIES ARE NOT SEEKING APPROVAL FOR THE WET COMPRESSION PROJECTS IN THIS FILING.

A. Normally, the Companies would request approval for all these projects, but since they have the opportunity to complete the upgrades on the Clark Peakers, Harry Allen simple cycle units and the Sun Peak units prior to the 2022 summer peak season, and have them available to meet peak customer's needs, the Companies decided to pursue these upgrades immediately.

13. Q. WHY DID THE COMPANIES NOT REQUEST APPROVAL OF THESE WET COMPRESSION PROJECTS IN THE INTEGRATED RESOURE PLAN FILED LAST YEAR (DOCKET NO. 21-06001)?

A. The feasibility of installing these upgrades was not certain at the time of the filing in Docket No. 21-06001. The Companies continued their due diligence and completed testing on the Clark Peaking units in the third quarter of 2021 to confirm the feasibility of these upgrades.

14. Q. PLEASE DESCRIBE THE PROPOSED PEAK FIRING PROJECTS FOR THE LARGE COMBUSTION TURBINES.

A. The upgrades to the General Electric 7FA combustion turbines at Chuck Lenzie Block 1 and 2, Harry Allen CC and the Tracy CC is expected to increase the peak capacity of each combined cycle block by approximately 12 MW. These upgrades will utilize the existing equipment but realize the additional capacity through new control upgrades utilizing the existing burners and combustion systems. These projects are estimated to cost $12 million per combined cycle block ($6 million per combustion turbine) and approximately $24 million combined, and will provide additional generation capacity at peak until the units' respective retirements.

This peak firing capability is intended for short duration and limited hours of operation while peak firing. The peak firing operation does come at additional "fired-hour" costs under the Long-Term Service Agreement ("LTSA"). Additional variable maintenance costs will be assigned to operation with peak firing to ensure the unit operation is economically utilized while addressing the additional maintenance expenses.

15. Q. PLEASE DESCRIBE THE PROPOSED THERMAL ENERGY STORAGE UPGRADE FOR THE LENZIE GENERATING STATION.

A. The Companies are requesting approval to add a thermal energy storage system at the Lenzie Station. This system would use the existing inlet air chilling system during periods when the chillers are not needed for unit operations to produce chilled water that would be stored in new insulated storage tanks. This chilled water would then be used over a six-hour period during peak and would allow the chillers to be taken out of service during that period. Taking the chillers out of service would reduce the chiller load by 18 MW and make that energy available to support customer needs.

16. Q. WHAT IS THE COST OF THE CHILLED WATER SYSTEM AT THE LENZIE STATION?

A. The project cost for the chilled water storage system is $13 million and would include insulated storage tanks, piping and pumping systems.

17. Q. WHY IS THIS UPGRADE NOT BEING CONSIDERED FOR THE OTHER LARGE COMBINED CYCLE PLANTS?

A. The Lenzie Station is the only large, combined cycle plant that currently has chillers. The other plants would require inlet chillers to be installed in addition to the chilled water system, which is not economical at this time.

SILVERHAWK PEAKING PLANT

18. Q. PLEASE DESCRIBE THE SILVERHAWK PEAKING PLANT THAT IS INCLUDED IN THE ALTERNATE PLAN.

A. Consistent with the Nevada Administrative Code ("NAC") the Companies' amended supply plan contains a diverse set of alternative plans.[1] As part of the Alternate Plan a simple cycle gas turbine is presented as diverse alternative to the 2-hour battery energy storage system ("BESS") that is requested as part of the Preferred Plan, The Companies modeled the Silverhawk Peaking Plant individually and as part of the Alternative Plan. The Silverhawk Peaking Plant would be a 200 MW nominally rated simple cycle peaking plant that would be installed at the Silverhawk Generating Station and interconnected at the existing 500 kV plant switchyard. The peaking units could provide a firm capacity resource that would not be dependent on ambient weather conditions and

[1] *See* NAC 704.937

could allow more operational flexibility in the Companies' bulk power system as more renewables are added and support the Companies' goals for zero net carbon emissions by 2050.

SUMMARY

19. Q. PLEASE SUMMARIZE YOUR RECOMMENDATION TO THE COMMISSION?

A. I am making the following recommendations:

1. I recommend that the Commission approve the request to install peak firing on the GE 7FA combustion turbines on the large combined cycle units at Harry Allen, Lenzie and Tracy.

2. I recommend that the Commission approve the thermal energy storage system at the Chuck Lenzie Generating Station.

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

A. Yes, it does.

JOHN W. LESCENSKI
MANAGER, PLANT ENGINEERING AND TECHNICAL SERVICES

Currently Manager, Plant Engineering and Technical Services at NV Energy, responsibilities include generation fleet-wide asset strategy development, technical support for new solar resource contracts, working to ensure the existing and future generation fleet of power plants meets the energy supply requirements of our customers while meeting the stringent emissions requirements for fossil-fired power plants.

Professional Experience

Joining Nevada Power (now NV Energy) in 1989 as an Engineer in Generation Engineering and Construction at the Reid Gardner Power Plant, progressing to Manager for strategy planning for integrating business planning with power plant operations, in conjunction as primary witness for Generation issues in regulatory filings of the Integrated Resource Planning, Depreciation Cases, and General Rate Cases. Leading development of 10-year Business Plans for all generating plants in the fleet, leading Reid Gardner 1-3 repowering/retirement analysis and providing input to Resource Planning for alternative analysis. Responsible for strategic assessments of NV Energy's generation fleet through plant condition assessments and long-term life span analysis.

- Technical Support for Renewable PPA contract RFPs and renewable project development
- Technical Support for Solar PPA contract compliance with Energy Contract Management
- Successfully completed the $54 million Nellis Solar PV2 project, installing a 15MW photovoltaic station on a closed landfill on the Nellis Air Force Base. Responsible as project manager from contracting and construction management through startup
- Successfully completed the $16 million King's Beach Power Plant replacement, responsible for the project from inception through start-up
- Lead early efforts in the development of the Ely Energy Center project
- Lead the study of the Valmy expansion alternatives
- Spearheaded the resource planning efforts for the retirement and decommissioning of the Clark Units 1-3 and their replacement with the new 600 MW Clark Peaking Plant.
- Coordinated with Environmental Services on the air permit application and permitting for the contemporaneous change for the Clark Peaker Project
- Coordinated the Reid Gardner emissions alternative analysis and resource planning approval and supported the regulatory filings for emissions upgrades and the eventual retirement
- Developed Life-Span Analysis Process (LSAP) to guide the decision making for determining the remaining economic useful life of a generating unit and reinvestment decisions to continue operations. This Process is now relied upon by the Public Service Commission of Nevada.
- Project Engineer for the Harry Allen Unit 4 simple cycle 7EA combustion turbine expansion project, supporting resource plan application/approval through turbine purchase and EPC bidding and contracting
- Lead technical analyst for the generation business services department, providing services as lead Owner/user inspector and subject matter expert supporting the Clark and Reid Gardner Plant Engineering Staff.

Education

Master of Arts in Economics – University of Nevada, Las Vegas ▪ 2019
    Professional Paper: Econometric Analysis of the Effect of Deregulation on Retail Energy Prices
Graduate Certification in Renewable Energy – University of Nevada, Reno ▪ 2013
Master of Business Administration – University of Nevada, Las Vegas ▪ 1996
Bachelor of Science in Mechanical Engineering – University of Southern California ▪ 1989

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

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, JOHN LESCENSKI, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

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

Date: March 18, 2022

JOHN LESCENSKI

CHARLES A. POTTEY

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

First Amendment to the
2021 Joint Triennial Integrated Resource Plan (2022-2041)
Docket No. 22-03___

Prepared Direct Testimony of

Charles A. Pottey

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

A. My name is Charles Pottey. I am the Director of Transmission Planning for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra," and together with Nevada Power, the "Companies" or "NV Energy"). My business address is 6100 Neil Road, Reno, Nevada. I am filing testimony on behalf of the Companies.

2. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS THE DIRECTOR OF TRANSMISSION PLANNING.

A. I am responsible for all transmission planning associated with integrated resource plans ("IRP"), compliance, generator interconnections and transmission service requests, including load addition functions for the Companies.

3. Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EMPLOYMENT EXPERIENCE.

A. I have a Bachelor of Science degree in Electric Power Engineering and a Master of Engineering degree in Electric Power Engineering, both from Rensselaer Polytechnic Institute. I am a registered Professional Engineer. I have more than 35 years of experience in the electric utility industry mostly with the Companies. I have experience in transmission planning, resource planning, distribution planning, rates and regulatory affairs, transmission business services and electric grid operations. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Pottey-Direct-1**.

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

A Yes, I have testified in many IRP, IRP amendments and rate case proceedings, including most recently in Docket No. 21-06001.

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

A. I sponsor the Transmission Plan section of the Supply Side narrative discussing the Companies' transmission systems and associated projects, as well as Technical Appendices TRAN-1 and TRAN-2. Additionally, I support the Companies' requests: (1) to construct the required transmission system network upgrades for the North Valley 45 megawatt ("MW") geothermal facility that will be connected to the Eagle Substation 120 kilovolt ("kV") bus, and (2) to construct the required transmission system network upgrades for the Reid Gardner 220 MW Battery Energy Storage System ("BESS") that will be connected to the Reid Gardner

Substation 230 kV bus. I also describe the Remedial Action Scheme ("RAS") that is being proposed for North Valmy Generating Station ("Valmy").

6. Q. PLEASE DESCRIBE THE EXHIBITS AND TECHNICAL APPENDICES YOU ARE SPONSORING.

A. I sponsor the following exhibits and technical appendices:

- **Exhibit Pottey-Direct-1** – Statement of Qualifications;

- Technical Appendix TRAN-1: Large Generator Interconnection Agreement for ORNI 36, LLC - Company HN – North Valley 45 MW geothermal facility with a point of interconnection at the existing Eagle 120 kV Substation; and

- Technical Appendix TRAN-2: Provisional System Impact Study for Reid Gardner 220 MW BESS facility with a point of interconnection at the existing Reid Gardner 230 kV Substation.

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

A. First, I discuss the proposed Valmy RAS that will eliminate the need for the transitional dispatch approach described in the 2021 Joint IRP, which could have resulted in the need to curtail generation at the Hot Pot solar project. I then describe the interconnection requirements for the North Valley 45 MW geothermal facility that will be connected to the Eagle Substation 120 kV bus and the Reid Gardner 220 MW BESS that will be connected to the Reid Gardner Substation 230 kV bus.

8. Q. WHY IS A RAS NEEDED AT VALMY?

A. In the Large Generator Interconnection Agreement ("LGIA") for the Hot Pot solar project, the Falcon-Coyote Creek 345 kV transmission line was identified as a required network upgrade at a cost of $48.04 million. In Docket No. 21-06001, the Companies informed the Commission that NV Energy intended to file a non-standard Designated Network Resource ("DNR") with the Federal Energy Regulatory Commission ("FERC") to implement a transitional interconnection approach. This approach would ensure that total generation supplied at Valmy remains within the 800-875 MW capacity limit, to avoid the need for the $48.04 million network upgrade. The Companies have determined that the installation of a RAS at Valmy is a better approach than filing the non-standard DNR at FERC to implement a transitional interconnection approach.

9. Q. WHAT IS THE ADVANTAGE OF THE RAS COMPARED TO THE NON-STANDARD DNR?

A. The use of a non-standard DNR and transitional interconnection approach would require the total generation at Valmy (Unit 1 and 2, Hot Pot and Iron Point) to be limited to 800-875 MW. This has the potential to require a curtailment of the Hot Pot solar project. Installing the RAS eliminates this potential of curtailment and allows Valmy Units 1 and 2, Iron Point and Hot Pot to all operate simultaneously at full output, if necessary. In addition, it is easier for the Companies' Grid Operation to more reliably operate the system because there is no need to monitor the level of total Valmy area generation, which has the potential to lead to errors. NV Energy also believes that this approach is consistent with the Commission's finding that Valmy Unit 1 should be available to contribute to NV Energy's resource adequacy and for the benefit of its customers until it is retired in 2025.

10. Q. HOW WOULD THE VALMY RAS OPERATE?

A. If an outage of the Valmy-Falcon 345 kV transmission line occurs that results in an overload of the Coyote Creek-Bell Creek 120 kV transmission line, a ramp down signal will be sent to Hot Pot. If the ramp down fails to relieve the overload within the required time frame, a trip signal will be sent to Hot Pot.

11. Q. WHAT IS THE COST OF THE VALMY RAS?

A. The estimated cost to install the Valmy RAS is $0.5 million.

12. Q. ARE THE COMPANIES REQUESTING COMMISSION APPROVAL OF THE RAS?

A. No. The Companies are not requesting Commission approval to move forward with the RAS. I have included this discussion as information only to provide the Commission an update that the Companies will not be filing a non-standard DNR.

13. **Q. PLEASE DESCRIBE THE INTERCONNECTION FACILITIES AND NETWORK UPGRADES ASSOCIATED WITH THE NORTH VALLEY PROJECT.**

A. The interconnection facilities required to accommodate the North Valley geothermal project include a new 120 kV terminal position at the existing Eagle 120 kV Substation and associated substation upgrades to accommodate the interconnection. In addition, there are shared network upgrades with two other projects in the area, designated as company HO and company HV. The upgrades include rebuilding the #146 and #118 lines and reconductoring and adding optical ground wire to the #113 and #190 lines. There is also a required first-in-time network upgrade for the Eagle Control Enclosure.

14. Q. WHAT IS THE BUDGET AND COST RESPONSIBILITY FOR THE NORTH VALLEY PROJECT INTERCONNECTION FACILITIES AND NETWORK UPGRADES?

A. The North Valley project is responsible for the cost of building its generator, lead line, and associated interconnection facilities, including required communications, protection, metering facilities and the new terminal position at the existing Eagle 120 kV Substation. The Transmission Provider's Interconnection Facilities ("TPIF") are estimated to cost $1.845 million, and the North Valley project is responsible for the actual cost of these facilities. Sierra is responsible for the cost associated with Network Upgrades, per the Open Access Transmission Tariff ("OATT"). There are no individual network upgrades required but there are shared network upgrades with companies HO and HV (North Valley, company HO and HV are collectively referred to as "Cluster Participants"). Shared Network Upgrades will be secured on a pro-rata basis based on the requested interconnection megawatt amount between the Cluster Participants based off the 2017F N-2.0 Rural North Cluster. In the event that any of the Cluster Participants change status, a re-allocation of the Shared Network Upgrade costs will be completed and a formal letter will be issued notifying the remaining participant(s) of their new pro-rata cost allocation of the shared Network Upgrades. North Valley will be required to provide security/collateral pursuant to Article 11 of the LGIA and Attachment L of the OATT for its pro-rata share of the shared Network Upgrades in the amount of $5,677,000 plus $1,003,000 for first-in-time shared Network Upgrades. The remainder of the shared Network Upgrades costs will be securitized by companies HO and HV.

15. Q. **CAN THE NORTH VALLEY PROJECT CONNECT TO THE SYSTEM PRIOR TO THE COMPLETION OF THE SHARED NETWORK UPGRADES?**

A. Yes. The North Valley project may interconnect under Provisional Interconnection Service, provided that its interconnection facilities and Eagle Substation upgrades are completed, but the Companies cannot guarantee available capacity. Any transmission capacity that may exist would be offered on an "as available" basis but there is no capacity that can be offered on a firm basis at this time. North Valley may request, at its sole cost, quarterly studies to be completed to update the amount of Provisional Interconnection Service until the full interconnection service may be provided.

16. Q. **THE LGIA FOR THE NORTH VALLEY PROJECT SHOWS THAT THE GENERATING CAPACITY FOR THE PROJECT IS 45 MW BUT THE CONTRACT WITH NV ENERGY IS ONLY FOR 25 MW. CAN YOU RECONCILE THE DIFFERENCE?**

A. Yes. The project developer has indicated that they are planning to develop the project in two phases. The first phase is being sold to NV Energy and is expected to have generating capacity of around 25 MW. Mr. Shane Pritchard discusses in his prepared direct testimony the power purchase agreement for the 25 MW from North Valley. Once the wells are drilled and the resource is determined, the project developer is planning to develop a second phase with 20 MW of generating capacity. The project developer, therefore, requested an interconnection for full 45 MW of generating capacity that it plans to have in service upon project completion.

17. Q. PLEASE DESCRIBE THE INTERCONNECTION FACILITIES AND NETWORK UPGRADES ASSOCIATED WITH THE REID GARDNER BESS.

A. Nevada Power was requested to provide interconnection and necessary network upgrades at the Reid Gardner 230 kV substation to support the addition of its Reid Gardner 220 MW BESS. Nevada Power will construct the facilities required to accommodate the new Reid Gardner 230 kV terminal position at the existing Reid Gardner 230 kV Substation, including required metering, telecommunications, 230 kV terminal addition and substation entrance and all TPIF.

18. Q. WHAT IS THE BUDGET AND COST RESPONSIBILITY FOR THE INTERCONNECTION FACILITIES AND NETWORK UPGRADES REQUIRED FOR THE REID GARDNER BESS?

A. The total estimated cost of the interconnection is $2.5 million. The transmission provider is responsible for $0.4 million in Network Upgrades and interconnection customer is responsible for $2.075 million in TPIF costs and $0.025 million in direct assign costs. For the purposes of this project, Nevada Power acts as both the transmission provider and interconnection customer.

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

A. Yes, it does.

STATEMENT OF QUALIFICATIONS

CHARLES A. POTTEY

My name is Charles A. Pottey. My business address is 6100 Neil Road, Reno, Nevada. I am the Director of Transmission and Distribution Planning for Nevada Power Company, dba NV Energy and Sierra Pacific Power Company, dba NV Energy.

I graduated from Rensselaer Polytechnic Institute with a Bachelor of Science Degree in Electric Power Engineering in 1975, and a Master of Engineering Degree in Electric Power Engineering in 1977.

I am a registered Professional Engineer in Colorado.

Since September of 2021 I have been employed as the Director of Transmission and Distribution Planning. I am responsible for all transmission and distribution planning associated with integrated resource plans ("IRP"), compliance, generator interconnections and transmission service requests, including load addition functions for the Companies. I am also responsible for regional and inter-regional transmission planning.

From April of 2015 until April of 2017, I was employed as the Director of Transmission Policy, Contracts and Business Services. I serve as the primary contact for new transmission customer requests for interconnections to the transmission grid. I ensure compliance with applicable regulations and response deadlines associated with the Open

Access Transmission Tariff (OATT). My staff negotiates and finalizes contracts with transmission customers for addition and withdrawal of generation interconnections, transmission service, ancillary services, and agreements for co-owned facilities. I lead the billing and settlement function of the energy imbalance market entity and OATT.

From April 2010 until April of 2015, I was employed as the Manager of Network and IRP Transmission Planning. I was responsible for leading a staff of engineers who perform transmission system analyses to evaluate the operation of Sierra's and Nevada Power's system and analyze required system additions. I recommended optimal transmission additions considering economics, feasibility, performance, and reliability of alternatives to provide reliable and economical electric service to Sierra and Nevada Power customers. I oversaw the evaluation of the long-range needs of the electric transmission system including capacity, reliability, voltage regulation, stability, and operation during contingency conditions to ensure compliance with all NERC and WECC transmission planning reliability requirements. I managed the preparation of the Transmission section of the Integrated Resource Plan and Energy Supply Plan filings.

From December 2004 until April 2010, I was employed as the Manager of the Long-Term Resource Planning. I was responsible for directing technical analysis to evaluate the capital cost, production cost, and reliability of various transmission, generation, purchase power, and demand side alternatives to ensure sufficient electric resources are available to provide reliable and economical electric service to Sierra Pacific Power and Nevada Power customers. I managed the preparation of the Integrated Resource Plan and

Energy Supply Plan filings. I directed the development of detailed system modeling to accurately represent system operating constraints including system transmission limitations for production costing studies of existing and future power supply options.

From February 2002 until December 2004, I was employed as principal consultant in Sierra's Long-Term Resource Planning Department. I was responsible for developing analysis of various resource options to ensure sufficient resources are available to reliability and economically serve Sierra and Nevada Power's electric customers.

From June 2000, until February 2002, I was employed as a Senior Rate Engineer in Sierra's Rates and Regulatory Affairs Department. I am responsible for preparing price analysis and developing rates for electric, gas and water services offered by Sierra Pacific and Nevada Power.

From January 1991 until June 2000, I was employed as a Senior Engineer in Sierra's Resource Planning department. I was responsible for performing technical analyses to evaluate the capital cost, production cost, and reliability of various generation, purchase power, and demand side alternatives to ensure sufficient electric resources are available to provide reliable and economical electric service to Sierra's customers. I developed detailed modeling of Sierra's system to accurately represent system operating constraints including system transmission limitations for production costing studies of existing and future power supply options. I have performed production costing, reliability, and economic analysis to evaluate the cost, benefits, and reliability of potential supply and demand side alternatives to satisfy specific future resource requirements. I have also evaluated the economics and reliability of Qualifying Facilities, Independent Power Producers, and other non-Sierra owned generation options.

From August 1988 until January 1991, I was employed as a Senior Engineer in Sierra’s Electric System Planning department. I was responsible for performing engineering studies to evaluate Sierra’s long range and operational transmission and distribution system requirements. I performed powerflow and stability studies to evaluate the operation of Sierra’s system and analyze required system additions and recommended optimal additions considering economics, feasibility performance, and reliability of the alternatives. I developed a loss evaluation procedure to calculate the present worth value of system losses. I evaluated system import and export constraints and prepared appropriate operating nomograms.

From November 1982 until August 1988, I was employed as a Senior Engineer in Sierra’s Electric System Control Center. I was responsible for providing technical support to Sierra’s Electric System Control Center to assure optimal system operation. I evaluated generation dispatch and scheduled power purchases to ensure Sierra system was operated in the most economic manner possible while maintaining required system reliability. I developed operating guidelines and procedures for transmission and distribution facilities.

From December 1979 until November 1982 McGraw Edison employed me as an Apparatus Engineer. I was Responsible for providing sales engineers, product departments, and electric utility customers throughout the Rocky Mountain region with technical assistance on the application, installation, testing, and maintenance of McGraw Edison's complete line of electrical equipment.

From August 1978 until December 1979 Tri–State Generation and Transmission Association, employed me as a Project Engineer. I was responsible for coordinating all project activities for major substation and transmission line additions.

From May 1977 until August 1978 McGraw Edison Company employed me as a Power System Engineer. I was responsible for performing analytical studies for electric utility clients. I performed insulation coordination studies, calculated system unbalances, evaluated negative sequence currents, and analyzed transient recovery voltages.

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, CHARLES POTTEY, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

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

Date: March 18, 2022

Charles A. Pottey
CHARLES POTTEY

SHANE PRITCHARD

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

First Amendment to the
2021 Joint Triennial Integrated Resource Plan (2022-2041)
Docket No. 22-03___

Prepared Direct Testimony of

Shane Pritchard

I. INTRODUCTION

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

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

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

A. I hold a Bachelor of Science Degree in Mechanical Engineering from the University of Buffalo in Buffalo, New York. I served in the U.S. Navy between 1991 and 1996. Before joining the Companies, I worked for Titanium Metals Corporation and then for Alstom Power. In my current role, I serve as Director of Renewable Energy and Origination. My responsibilities include the procurement and contract negotiations for renewable and non-renewable energy resources. More details regarding my professional background and experience are set forth in **Exhibit Pritchard-Direct-1**.

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

A. Yes. Most recently, I provided written testimony in Docket No. 21-06001, the 2021 Joint Integrated Resource Plan ("IRP").

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

A. I sponsor the Companies' Long-Term Power Purchase Agreements and Renewable Energy Plan, Section 6 in the Supply Side Plan narrative of the First Amendment to the 2021 Joint IRP ("Amendment"). Specifically, I explain and support the Companies' plan for complying with Nevada's renewable portfolio standard ("RPS"). I also provide support for Sierra's execution of a new power purchase agreement ("PPA") with ORNI 36, LLC ("Ormat") for the North Valley Geothermal facility ("North Valley") in Washoe County, Nevada.

5. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibits:

- **Exhibit Pritchard-Direct-1** Statement of Qualifications
- **Exhibit Pritchard-Direct-2** Key provisions of the North Valley PPA

6. Q. WHAT MATERIALS ARE YOU SPONSORING?

A. I sponsor the following Technical Appendices:

- REN-1 Renewable Project 12x24 Supply Table;
- REN-2 Renewable Portfolio Standard Buildout Scenarios;
- REN-3 NV Long-term Renewable Power Purchase Agreement with ORNI 36, LLC;
- REN-4 North Valley Regulation Roadmap;

- REN-5 North Valley Due Diligence Summary (Confidential).

7. Q. ARE THE COMPANIES REQUESTING CONFIDENTIAL TREATMENT OF CERTAIN INFORMATION CONTAINED IN YOUR TESTIMONY?

A. Yes. Technical Appendix REN-5 is confidential as it contains the Companies' due diligence review of the North Valley project, which, if publicly disclosed, could provide an unfair market advantage to competitors by showing the Companies' internal analysis of projects. Confidentiality of the Companies' technical evaluation of bids is essential to future successful negotiations and competitive solicitations.

In addition, the Companies request that the precise pricing of the North Valley PPA receive confidential treatment. As explained in my Q&A 24, the PPA is competitively priced and represents one of the best values the Companies have been able to receive for a geothermal resource. The project's developer is currently in negotiations with a number of out-of-state load-serving entities for its other geothermal resources. Disclosure of the North Valley PPA pricing information will undermine the developer's negotiating position with those other entities which will in turn create a disincentive for the developer to enter into competitively priced PPAs with the Companies in the future. Such a disincentive will negatively affect the Companies' ability to negotiate the best terms and secure diverse renewable resources for their customers.

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

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

9. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF THE REGULATORY OPERATIONS STAFF ("STAFF") OR THE BUREAU OF CONSUMER PROTECTION ("BCP") TO PARTICIPATE IN THIS DOCKET?

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

10. Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY?

A. In section II, I discuss the Companies' plans to comply with Nevada's RPS. In section III, I discuss Sierra's request for approval of the North Valley PPA, specifically:

1. The reason for bringing it forward;
2. The selection and design; and
3. The description, price competitiveness and benefits.

II. THE COMPANIES' PLAN FOR COMPLYING WITH NEVADA'S RPS

11. Q. PLEASE DESCRIBE NEVADA'S RPS.

A. Nevada utilizes a portfolio energy credit ("PC") system to measure RPS compliance. Eligible PCs can come from multiple sources beyond just net current year renewable generation. The most common source of PCs from non-current year net renewable generation are banked PCs rolled forward from prior compliance years, eligible station usage PCs, grandfathered solar multiplier PCs, and finally PCs derived from energy efficiency and demand response programs.

Nevada's RPS requirement for calendar year 2022 is set at 29 percent of retail sales.[1] This means that Nevada Power and Sierra must have PCs equal to 29 percent of their respective retail sales. The RPS will increase to 34 percent in 2024, 42 percent in 2027, and 50 percent in 2030, and remain at 50 percent each calendar year thereafter.[2]

12. Q. PLEASE DESCRIBE THE RPS RENEWABLE PLAN DEVELOPED FOR THE AMENDMENT.

A. The Companies use a model to forecast future PC requirements and PC supplies. The purpose of the model is to determine whether the Companies will have sufficient PCs to meet their RPS obligations. If, outside the IRP action period, the model indicates that the PC supply is insufficient to meet the RPS, generic placeholder projects are added, as needed, to fill the credit gaps. Key inputs to the model include a list of current operating renewable resources, all approved renewable resources under development or construction, and all other sources of eligible credits. The model incorporates all statutory and regulatory limitations, as well as non-RPS portfolio credit obligations, in order to calculate the total number of eligible credits available to meet the RPS for each planning year. This total is then compared against the forecast credit requirement to determine whether each company will have sufficient PCs to meet its RPS obligation. Below are the key assumptions that are incorporated into the model:

- Full compliance with an escalating and compressed RPS schedule: 29 percent in 2022, 34 percent by 2024, 42 percent by 2027, and 50 percent by 2030; and

[1] Nevada Revised Statutes ("NRS" § 704.7821
[2] *Id*.

- Ensuring enough renewable capacity to satisfy a strong and growing demand from the Nevada business community to meet their energy needs from carbon-free, sustainable energy.

The Companies used the same renewable placeholder buildout developed for the 2021 Joint IRP Preferred Plan. The expected PC supply was determined starting with the current portfolio of approved projects, both operating and under development or contemplated by the Companies. The following assumptions are built into the forecast:

- Existing PPAs expire in accordance with the contract terms and are not automatically renewed;[3]
- The Companies adjusted the expected amount of energy and PCs from renewable facilities for the period of 2021-2024 in cases where the historic generation, based on two or more years of data, consistently varied from that of the contractual or expected supply table. This is consistent with the methodology that the Companies used for the past several years in developing their IRPs and Energy Supply Plans. This adjustment recognizes that options to address underperformance within a shorter planning window are limited. It also aligns the short-term and long-terms plans;
- The projected number of PCs derived from the Renewable Generations incentive programs plateaued in 2020 with the last of the incentivized solar systems now installed. Starting in 2021, the expected number of credits from incentivized rooftop solar is forecasted to begin decreasing by 0.5 percent per year as these systems age and their output slowly begins to decline. Solar systems placed into

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

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

- The plan assumes that the percent of annual PC requirements based on demand side management ("DSM") measures is limited to no more than 10 percent of the credit total for 2021 through 2024 before dropping to zero effective 2025. The plan also assumes, based on current DSM kPC projections, that Sierra may not have a sufficient number of DSM PCs to completely fill the 10 percent cap in 2023 and 2024;
- Surplus PCs are carried forward without limitation and the plan assumes no surplus PC sales;
- Nevada Power repaid the final 538,438 kPCs that it owed Sierra in 2021. The balance owed to Sierra is now zero;
- The plan assumes that generation from both company-owned solar photovoltaic ("PV") systems and PPA projects would be degraded starting the year following the first full year of operation. Geothermal generation would continue to qualify for station usage credits, while all other technologies would no longer qualify;
- The plan accounts for all Commission approved NV GreenEnergy Rider ("NGR") and Energy Supply Agreements ("ESAs"), with the exception of the new NGR tariff, as of January 31, 2022, where PCs associated with all or a portion of the output from a renewable facility(s) have been assigned to a customer under the NGR, the Market Price Energy or Large Customer Market Price Energy tariffs, and, therefore, cannot be used by the Companies in meeting their RPS credit requirements;
- The plan adjusts the retail sales total that is used to calculate the RPS requirement to exclude sales to bundled NGR or ESA customers, and other customers participating in a program of optional pricing that includes the transfer of PCs

above that required for RPS compliance in an amount that is equal to the number of credits transferred to or retired on behalf of the participating customers;

- The plan incorporates the results of the 2022 NGR Open Season;
- The plan assumes that the net energy produced by Hoover and allocated to Nevada Power counts towards meeting the RPS;
- The plan assumes no changes to the existing statutory and regulatory RPS regime;
- The plan includes Iron Point 250 MW PV with BESS and Hot Pot Solar 350 MW PV with BESS, with the energy and PCs split 56 percent Nevada Power and 44 percent Sierra;
- The plan assumes the approval of the proposed North Valley Geothermal PPA. North Valley Geothermal is a 25 MW geothermal plant with an estimated commercial operation date of December 31, 2022. Sierra will be the sole off-taker of the energy and PCs. The total number of PCs from this project includes station usage PCs. Certain geothermal station usage, the energy for the extraction and transportation of geothermal brine or used to pump or compress geothermal brine, is eligible for certification under the NRS 704.78215(3)(b). Station usage PCs for this facility were estimated at 15 percent of net;
- The annual amount of energy produced by solar PV systems paired with BESS has been reduced to account for battery losses. The adjustment recognized that not all of the energy produced by PV arrays paired with energy storage will be delivered real-time to the grid. Some of the energy will be stored and dispatched at a later time when needed. The process of charging and discharging the batteries will result in energy losses; and
- An adjustment has been added to the model to capture the generation and PCs lost due to resource curtailment. This adjustment recognizes that as renewable energy becomes a dominant source of generation, there will be times when the

transmission system cannot accommodate all of the energy being produced making generation curtailment necessary to maintain grid integrity.

13. Q. PLEASE EXPLAIN THE ASSUMPTIONS AND METHODOLOGY UNDERLYING THE RENEWABLE EXPANSION PLAN

A. The renewable expansion plan captures actual historical generation trends based on two or more years of operating data. The Companies adjusted the supply table based on this historical trend to reflect the most recent operating data after coordinating with internal contract owners to account for potential short-term anomalies. Historical output trends for Sierra-contracted renewable projects resulted in an adjustment to ten projects with both increases (two projects) and decreases (eight projects). In total, these adjustments lowered the amount of renewable energy by an average of 2.3 percent over the 2022-2024 IRP action plan period.

The same approach for Nevada Power resulted in adjustments to the amount of renewable energy for four projects, with two increases and two decreases. In total, these adjustments lowered the amount of renewable energy by an average 0.7 percent over the 2022-2024 action period. The Companies believe that this approach maximizes the reliability and accuracy for the overall energy supply used in short-term planning.

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

A. Nevada Power exceeded the 2020 RPS requirement of 22 percent ending 2020 with an overall RPS compliance result of 28.5 percent. Nevada Power is expected to exceed the 2021 RPS requirement of 24 percent when it submits its 2021 annual

RPS compliance report in April 2022. It is also currently positioned to meet its 2022-2025 RPS obligations. Although the forecasting model indicates that Nevada Power should have sufficient PCs to fully comply with the RPS through 2036, this long-term forecast is not without risk. First, there is still the risk that one of the current renewable resources could develop an issue resulting in lost PCs. Second, there is the risk that one or more of the nine approved pipeline PPAs[4] could be delayed or worse yet cancelled. In fact, the Eagle Shadow Mountain project is experiencing a delay in delivery of some of its solar modules, a challenge that is now common in the industry. While most of the 300 MW facility is operational, it can only produce approximately 249 MW until the remainder of the modules are placed in service. In order to meet the higher PC requirement, pipeline projects are expected to achieve their PPA milestones as any credits lost due to start up delays or downward adjustments to post operational energy supply tables cannot be easily or quickly replaced.

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

A. Sierra exceeded the 2020 RPS requirement of 22 percent ending 2020 with an overall RPS compliance result of 30.2 percent. Like Nevada Power, Sierra is also projected to exceed 2021 RPS requirement of 24 percent when the company submits its 2021 annual RPS compliance report in April 2022. The forecasting model indicates that Sierra is currently positioned to meet its 2021-2024 RPS obligations and the outlook can be summed up as optimistic. While Sierra has been very successful in building a pipeline of new projects to meet its future credit needs,

[4] Eagle Shadow Mountain, Arrow Canyon, Southern Bighorn, Chuckwalla, Boulder Solar III, Dry Lake Solar, Gemini Solar, Iron Point, and Hot Pot.

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

its compliance outlook is not without risk. Until the six current pipeline projects achieve commercial operation, there is the risk of delays or cancelations.[5] In fact, both the Dodge Flat and Fish Springs Ranch experienced minor delays in reaching commercial operation though, as of this filing, both are expected to reach commercial operation approximately before the end of March 2022. Second, there is the risk that one or more of its current operating projects could experience an unexpected issue, resource and/or mechanical, and fall short on its generating commitments. Finally, Sierra could experience unexpected load growth. With an escalating RPS, even small increases in retail load growth beyond what is forecasted can increase the company's credit need by thousands of credits.

16. Q. TO WHAT EXTENT WOULD THE APPROVAL OF THE NORTH VALLEY GEOTHERMAL PROJECT BENEFIT SIERRA'S COMPLIANCE OUTLOOK?

A. The approval of North Valley gives Sierra a new baseload renewable resource in a very quick time frame, December 31, 2022. The 24x7 energy generated by the facility will help offset renewable energy and credits not received from the two delayed projects, Dodge Flat and Fish Springs Ranch, discussed above. It will also help replace the geothermal energy lost as several Sierra long-term geothermal PPAs are set to expire in the near term. Finally, it helps to get Sierra one step closer to its goal of providing 100 percent carbon-free energy to its customers.

[5] Dodge Flat, Fish Springs Ranch, Arrow Canyon, Southern Bighorn, Hot Pot and Iron Point.

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III. NORTH VALLEY GEOTHERMAL PPA

17. Q. WAS NORTH VALLEY BID IN A RENEWABLE ENERGY REQUEST FOR PROPOSALS ("RFP")?

A. Yes, Ormat submitted the North Valley project in the 2020 Fall Renewable RFP that closed on October 27, 2020. North Valley's 25-year PPA term bid, which was shortlisted for negotiations, was the only compliant geothermal bid that went through the pricing and technical evaluation.

18. Q. PLEASE COMMENT ON THE EVALUATION AND NEGOTIATIONS TIMELINE FOR NORTH VALLEY.

A. Sierra completed North Valley's technical and pricing due diligence in November 2020, however, Sierra did not receive Ormat's confirmation to proceed with negotiations until June 2021. Ormat's confirmation also included an updated capacity of 25 MW (net) based on its further evaluation of the geothermal resource compared to the 30 MW (net) bid submitted in October 2020. This resulted in an updated levelized cost of energy estimate but did not impact any other due diligence items. The due diligence summary for North Valley is included as **Confidential Technical Appendix REN-5**. Negotiations were completed in the fourth quarter of 2021.

19. Q. PLEASE DESCRIBE ANY ADDITIONAL ANALYSIS CONDUCTED FOR NORTH VALLEY.

A. The Resource Planning group conducted a present worth revenue requirement ("PWRR") analysis of North Valley. The PWRR analysis is described in the Economic Analysis section of the narrative.

Additional due diligence was conducted on the North Valley project. The due diligence included: (1) status and timing of interconnection, (2) evaluation of site control, (3) status of material permits, (4) review of material equipment for bankability and performance, (5) determination of whether the project development milestone schedule supports contractual commercial operation date, (6) evaluation of development and operating experience of the developer, (7) evaluation of the developer's financial capability, (8) evaluation of developers' jobsite safety performance history, and (9) evaluation of the available water supply.

Based on this analysis, no material concerns were raised. Sierra's due diligence summary is included in **Confidential Technical Appendix REN-5**. As a result, Sierra successfully completed PPA negotiations with Ormat for the North Valley facility. The PPA is described in more detail below.

20. Q. PLEASE DESCRIBE THE NORTH VALLEY PPA.

A. Sierra and Ormat executed the North Valley PPA on November 10, 2021. The 25-year agreement for North Valley is for 25 MW (net) of capacity from a new geothermal electric generation facility to be constructed on private land in Washoe County, Nevada. The project is expected to produce 217,617 MWh of renewable energy and associated PCs annually.

The North Valley geothermal project will utilize binary geothermal technology, which is Ormat's in-house technology to fully utilize the geothermal resource while ensuring highest availability. The electrical generation process utilizes the geothermal brine as fuel, with the conversion to electrical energy accomplished by means of a dedicated Ormat modular geothermal power plant and a geothermal turbine. The brine and steam originate from production wells and then flow through the Ormat Energy Converter ("OEC"). At the end of the process, the geothermal brine is reinjected into the ground through injection wells. OEC units will use the Organic Rankine Cycle, which uses a closed loop system where the heat source is the geothermal fluid, and the motive fluid is pentane. The pentane is first preheated in the preheater before entering the vaporizer. The hot brine also flows into the vaporizer to evaporate the pentane. Afterwards, the brine flows into the preheater and exits the OEC to the re-injection wells. The pentane vapors flow onto the turbines' blades, which turn the common generator shaft to produce electricity. Next, the motive fluid vapors exit through the turbine outlet into air-cooled condensers. These condense the pentane vapors into a liquid phase. Following, the condensed pentane is pumped by the feed pumps into the pre-heaters for an initial warm up. Lastly, it flows into the vaporizers to begin the cycle again. Binary geothermal facilities built by Ormat, utilizing the OEC, have proven successful for decades.

North Valley's contractual commercial operation date is December 31, 2022. The fixed PPA price is $[redacted] per MWh. This price is flat for the term of the contract and includes all costs associated with both the generating plant and renewable energy attributes. The levelized cost of energy ("LCOE") of North Valley is $59.17 per MWh, and $5,677,000 is the supplier's pro-rata share of the network upgrades necessary to interconnect the project to the 120 kilovolt ("kV") Eagle Substation.

21. Q. WHAT ARE THE BENEFITS THE NORTH VALLEY GEOTHERMAL PPA BRINGS TO SIERRA, ITS CUSTOMERS AND THE STATE?

A. North Valley is the first diverse geothermal resource in northern Nevada to contract with Sierra in more than a decade. In addition to the energy and capacity, customers will benefit from all associated environmental and renewable energy attributes as North Valley will help displace fossil-fueled generation. North Valley will also help to close Sierra's open capacity position and provide night-time renewable energy in support of the zero-carbon goals. Ms. Anita Hart provides further discussion on the capacity benefits of North Valley in her prepared direct testimony. North Valley is dispatchable and can provide a load-following capability, which will help balance Sierra's renewable energy portfolio especially considering the solar PV and BESS projects that either recently became commercial or are under development. For example, North Valley will expand Sierra's current geothermal portfolio of approximately 428.6 MW (8.38 percent of total renewables capacity) compared to 4,263 MW (83.36 percent of total renewables capacity) of solar.[6] The predictable, weather-independent, and around-the-clock generating profile provided by North Valley becomes increasingly attractive as it will continue to help avoid exacerbating the solar PV generating peak. In addition, the Legislature established an aspirational goal of achieving by 2050 an amount of energy production from zero-carbon dioxide emission resources equal to the total amount of electricity sold by providers of electric service in this State and North Valley will help achieve that goal.[7]

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[6] Including both existing commercial and pre-commercial (approved and pending approval by the Commission) renewable resources as of December 31, 2021.
[7] NRS § 704.7820

22. Q. WHAT KEY PROVISIONS HAS SIERRA NEGOTIATED WITH ORMAT?

A. **Exhibit Pritchard-Direct-2** provides a table detailing the key provisions of the North Valley PPA, and the PPA between Sierra and ORNI 36, LLC is included as **Technical Appendix Item REN-3**.

23. Q. IS THE PPA PRICE FOR NORTH VALLEY COMPETITIVE?

A. Yes. First, North Valley's price ($[redacted] per MWh) is approximately 41 percent lower than the last geothermal energy price approved by the Commission in Docket No. 11-08010 for the USG San Emidio geothermal facility ($97.76 per MWh). Second, North Valley's pricing is also approximately 24 percent lower than the average geothermal PPA pricing for existing PPAs ($75.99 per MWh). Third, North Valley was the only geothermal resource for which a compliant bid was submitted in the 2020 Fall RE RFP that resulted in the best category pricing score based on its LCOE ($59.17 per MWh). Finally, the North Valley PPA price is at near or below the lower range of LCOE forecast and recent publicly available geothermal PPA pricing published by National Renewable Energy Laboratory ("NREL").[8]

24. Q. WHY ARE THE COMPANIES PROPOSING GEOTHERMAL NOW WHEN MODELING RESULTS FAVOR ALTERNATIVE TECHNOLOGIES?

A. North Valley is exceptional in that its price is only $[redacted] per MWh, significantly lower than that used in past modeling placeholder pricing and comparable to or lower than any of NV Energy's current geothermal contracts. Furthermore, the opportunity to contract for baseload renewables is not nearly as abundant as solar and could become even more scarce as California also seeks to increase its already

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[8] Refer to pages 17 and 21 for publicly available geothermal pricing references, available at https://www.nrel.gov/docs/fy21osti/78291.pdf.

substantial stake in geothermal energy, which may create increased demand for Nevada's geothermal resources.[9] The opportunity to contract for North Valley or a similar resource may not actually be available when resource modeling determines the optimal time to add it.

25. Q. WILL THE NEVADA ECONOMY BENEFIT FROM APPROVAL OF THE NORTH VALLEY PROJECT?

A. Yes, the Nevada economy will benefit from the approval of this project. The North Valley project is expected to produce approximately 300 construction jobs during the construction phase of the project. Moreover, the construction work will be completed pursuant to work site agreements with the International Brotherhood of Electric Workers Local 1245 and 401. In addition to the construction jobs and associated positive economic impacts, the facilities will provide a permanent, long-term increase in employment with the addition of up to 20 permanent positions with a corresponding payroll of $48.5 million over 25 years. The North Valley project will have a capital investment of $90 million during construction and the local and state economies will benefit from the influx of jobs, tax base, and business generated by these projects. **Technical Appendix REN-4** sets forth a complete listing of the economic and environmental benefits of the North Valley project, as required by the Commission's regulations.[10]

[9] U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, *Chapter 2: Geothermal Takes the State*, February 1, 2022, available at https://www.energy.gov/eere/articles/chapter-2-geothermal-takes-stage.
[10] *See* Nevada Administrative Code § 704.8887(2).

26. Q. PLEASE SUMMARIZE SIERRA'S REQUEST TO APPROVE THE NORTH VALLEY PROJECT.

A. The Companies request that the Commission approve the North Valley PPA for 25 MW (net) of new geothermal generation between Sierra and the ORNI 36, LLC, with an expected commercial operation date of December 31, 2022. This project will help support native load customer needs at historically low pricing for a geothermal resource.

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

A. Yes.

SHANE E. PRITCHARD
6226 West Sahara Ave.
Las Vegas, NV 89151-001
702-439-3545
spritchard@nvenergy.com

EDUCATION: BS - Mechanical Engineering - University of Buffalo – 1991

NV Energy:

2018 – Present: Director, Renewable Energy and Origination

Responsible for the evaluation of strategic renewable opportunities that increase shareholder and customer value. Directs contract negotiations and oversees the delivery of the supply side Action Plan outlined in the Integrated Resource Plan for origination-related activities. Ensures alignment with short and long-term organizational goals and objectives. Works closely with top executive management to keep them apprised of strategic opportunities and challenges.

2015 – 2018: Senior Project Manager for Renewable Energy and Origination

Responsible for developing customer proposals for green power and customer choice programs and due diligence assessment of potential generating asset purchases. Supported bid and regulatory processes for contracting new renewable assets and develops testimony and responds to data requests in support of regulatory filings. Project manager and customer-facing representative for new commercial businesses interfacing with generating stations. Developed generation projects and strategies to solve transmission and distribution problems.

2014 – 2015: Operations Manager for Silverhawk Station

Led a team in the operation of a 600 MW combined cycle power plant. Responsible for personnel safety, plant performance, operations budget, NERC/WECC compliance, environmental compliance and compliance with applicable OSHA and other safety regulations. Planned and facilitated personnel training and led several continuous improvement efforts including implementation of Human Performance Improvement methods and enhanced event reporting.

2012 – 2014: Maintenance Manager for Arrow Canyon Complex
2009 – 2012: Operations & Maintenance Manager for Silverhawk Station
2008 – 2009: Engineering Manager for Arrow Canyon Complex
2007 – 2008: Maintenance Manager for Chuck Lenzie Station
2005 – 2007: Plant Engineer for Chuck Lenzie Station

Other experience:

2000 – 2005: **Alstom Power - Field Service Engineer**

- Plant inspections, emissions tuning, technical consultant and project leader for plant retrofits
- Business development and customer relations

1997 – 2000: **Titanium Metals Corporation (Timet) - Project Engineer**

- Implemented capital projects from design through commissioning in support of plant operations

US Navy:

1991 – 1996: **US Navy Nuclear Power**

Test Director: USS Abraham Lincoln dry-dock overhaul

- Planned, scheduled and executed complex nuclear reactor plant tests
- Managed shipyard and Navy efforts to repair and upgrade reactor plant systems
- Assisted civilian electrical engineers in E&IC system troubleshooting

Reactor Electrical Division Officer: USS Abraham Lincoln at sea
- Led and trained 30 electricians to operate and maintain propulsion plant electrical systems
- Operated nuclear power plants and maintained associated reactor electrical systems
- Aircraft carrier operations Officer of the Deck

EXHIBIT PRITCHARD-DIRECT-2

KEY PROVISIONS OF THE NORTH VALLEY POWER PURCHASE AGREEMENT

PROVISION	NORTH VALLEY GEOTHERMAL
Owner	ORNI 36 LLC
Off Taker	Sierra Pacific Power Company, dba NV Energy
Term	25 years
Total Average Capacity	25 MW
Expected Commercial Operation	December 31, 2022
Product Description	Geothermal Electric Generation
Yearly PC Amount (Contract Year 1)	208,442 kPCs
Maximum Amount	38.5 MWh in any hour
Degradation	Annual Supply Amount and Yearly PC Amount each decline by 0.5% per year.
Pricing	
Product Rate	[redacted]
Excess Energy Rate	[redacted]
Excess Energy	Delivered amounts above the Maximum Amount for Operating Year
Test Product Rate	[redacted]
Maximum Amount	No payment for amounts delivered above the Maximum Amount in any hour delivered to the grid
Energy Delivery Requirements	
Measurement Period	Each two (2) consecutive Contract Years commencing with the first two (2) Contract Years of the Term
Shortfall Threshold	With respect to each Measurement Period, if the sum of all delivered amounts (not including Excess Energy) is less than the product of (a) .90, and (b) the difference between (i) the Supply Amount for such Measurement Period, minus (ii) the total amount of Energy associated with Excused Product, then a shortfall of Energy with respect to such Measurement Period will be deemed to exist.

Shortfall Amount	Equals (a) the applicable Measurement Period Supply Amount minus (b) the total amount of Energy associated with Excused Product Amount (if any) for such Measurement Period, minus (c) the sum of all Delivered Amounts (not including Excess Energy). For the avoidance of doubt, if the calculation set forth in the preceding sentence yields an amount of zero or less for a Measurement Period, then no Measurement Period Shortfall Amount will be deemed to exist with respect to such Measurement Period.
Replacement Cost	Equals (a) the Shortfall Amount, multiplied by (b) the amount equal to (i) the Buyer's cost to replace the Shortfall Amount (as described in the following sentence) minus (ii) the Product Rate. The Buyer's cost to replace any Shortfall Amount, with respect to each MWh of Shortfall Amount, will equal the Measurement Period Index. Notwithstanding anything in the foregoing to the contrary, if the calculation of Replacement Costs yields an amount of zero or less for a Measurement Period, then no Replacement Costs will be payable with respect to such Measurement Period.
Voltage Support	The Interconnect Agreement (IA) requires the Facility to maintain a composite power delivery at continuous rated power output at the point of interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established different requirements that apply to the Facility and all generators in the control area on a comparable basis. In addition to the requirements of the IA, the Facility will provide voltage set point control at the point of interconnection within the range of 0.90 leading to 0.90 lagging at full rated real-power output, as available, within the capabilities of the Facility. Additional details are included in Section 3.5.4 of the PPA.
	PC Delivery Requirements
Measurement Period	Each two (2) consecutive Contract Years commencing with the first two (2) Contract Years of the Term
PC Shortfall Amount	Sum of all Delivered PCs is less than the product of (a) 0.90 multiplied by (b) an amount equal to (i) the sum of the Yearly PC Amount for the Contract Years in such Measurement Period minus (ii) the total amount of PCs associated with Excused Product during such Measurement Period.
PC Replacement Cost	Determined by Buyer exercising its reasonable discretion based on the average PC replacement cost to replace the PC Shortfall Amount from the same resource type with a comparable expiration date or the cost of replacing the PC Shortfall Amount with PCs of Buyer's choice already in

	Buyer's PC Account; provided, however, that Buyer shall not be required to actually purchase replacement PCs in order to receive payment from Supplier for PC Replacement Costs. Buyer shall include in the PC Replacement Costs any Penalties allocable to Supplier's proportionate amount of Buyer's aggregate shortfall under the applicable Portfolio Standard (factoring in Supplier's shortfall in prior years carried forward as a deficit or reducing the surplus in such prior years).
Delay Damages, Deficit Damages	
Daily Delay Damages	Equals to: (a) with respect to the first 90-day period of delay beyond the Commercial Operation Deadline, \$1,449.69 per day; (b) with respect to the second 90-day period of delay beyond the Commercial Operation Deadline, \$4,349.10 per day; (c) with respect to the third 90-day period of delay beyond the Commercial Operation Deadline, \$8,698.19 per day; and (d) with respect to the fourth 90-day period of delay beyond the Commercial Operation Deadline, \$10,503.02 per day.
Nameplate Damages	If the Certified Nameplate Capacity Rating is less than 18.75 MW, Supplier shall provide Buyer a onetime payment in an amount equal to (a) subtracting (i) Certified Nameplate Capacity Rating from (ii) 18.75 MW, multiplied by (b) Deficit Damages Rate per MW of \$250,000 per MW. Notwithstanding the foregoing, for purposes of achieving the Commercial Operation Date, if the Certified Nameplate Capacity Rating is less than 18.75 MW but greater than 17.5 MW, Supplier shall, for purposes of declaring the Commercial Operation Date pay the Deficit Damages, and. In no event shall the Certified Nameplate Capacity be less than 17.5 MW or more than the Maximum Amount. Supplier's total liability for Deficit Damages shall not exceed one million five hundred thousand dollars (\$1,500,000).
Termination Rights	
Force Majeure	Supplier's obligations may be excused by an event of Force Majeure

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, SHANE PRITCHARD, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

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

Date: March 18, 2022

SHANE PRITCHARD

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

ZELJKO VUKANOVIC

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

First Amendment to the
2021 Joint Triennial Integrated Resource Plan (2022-2041)
Docket No. 22-03___

Prepared Direct Testimony of

Zeljko Vukanovic

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

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

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

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

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

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

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

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

A. I am sponsoring the wholesale power and natural gas price forecasts ("Price Forecasts") that are presented in Section 4 of the Companies' First Amendment to their 2021 Joint Integrated Resource Plan ("Amendment"). I also sponsor the following Technical Appendix item, which is confidential:

- FPP-1 - Fuel and Purchased Power Price Forecasts.

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

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

- Figure PF-2 – Annual Average Gas Price Forecast
- Figures PF-3 and PF-4 – Average Market Implied Heat Rate Forecast
- Figures PF-5 and PF-6 – Average Annual Power Price Forecast
- Figures PF-7 and PF-8 – Base, High and Low Gas Price Forecast
- Figures PF-9 and PF-10 – Base, High and Low Power Price Forecast
- Figure PF-11 – Projected Capacity Prices

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

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

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

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

7. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF THE COMMISSION'S REGULATORY OPERATIONS STAFF ("STAFF") OR THE NEVADA ATTORNEY GENERAL'S BUREAU OF CONSUMER PROTECTION ("BCP") TO FULLY INVESTIGATE THE INTEGRATED RESOURCE PLAN?

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

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

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

Exhibit Vukanovic-Direct 1 **-** Statement of Qualifications

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

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

10. Q. PLEASE BRIEFLY DESCRIBE THE CHANGES IN NATURAL GAS AND PURCHASE POWER PRICE FORECASTS IN THIS AMENDMENT AS COMPARED WITH 2021 IRP PRICE FORECASTS.

A. The fuel and purchased power price forecasts used in this Amendment are based on higher observed power, coal and natural gas market quotes used in the short-term forecast, as well as higher, newly released long-term market fundamental price forecast. These Price Forecasts are presented in Section 4 of the Amendment.

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

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

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

trading hubs Mead, Palo Verde, Mid-Columbia ("Mid-C"), and California-Oregon Border ("COB").

The long-term fundamental price forecast is obtained from WoodMac, which publishes its fundamental price forecast (Long-term outlook or "LTO") bi-annually. The price curves in this filing are based on the no-carbon case: "North America power markets 2021 outlook to 2050 – Policy Headwinds" released by WoodMac in October of 2021. WoodMac performs detailed modeling of regional natural gas and power markets, taking into account supply-demand price dynamics. The published no-carbon case ("Policy Headwinds") presents a status quo view that considers current policy only, with very limited exceptions. Current U.S. federal tax credits are assumed to phase out as scheduled and state-level policies, such as renewable portfolio standards and regional carbon pricing (e.g. RGGI), continue to be the primary drivers of emissions policy in the absence of federal policy. The market fundamentals in this no-carbon case serves as the foundation in building the price forecasts included as Technical Appendix Item FPP-1.

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

A. All alternatives were evaluated against a base case natural gas price forecast assuming an adjustment to the Henry Hub price due to the expected effects associated with implementation of the U.S. Environmental Protection Agency's anticipated federal cap-and-trade program. NERA Economic Consulting ("NERA") developed projected

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impacts to the Henry Hub natural gas price should the program be implemented as proposed. Consequently, for the base case, the natural gas price forecast was adjusted by anticipated market impacts of the program beginning January 2023. The near-term (January 2022 through March 2025) market quotes for power and gas are based entirely on the average of settlement prices during 21 trading days in November 2021. The Price Forecasts transition from being entirely market-based price quotes to entirely long-term fundamental forecast during a 24-month blending period from April 2025 through March 2027. The near-term market-based quotes are incrementally blended with the long-term fundamental forecast across this transition period.[2] The Companies used the pure fundamental forecast for the April 2027 through December 2051 portion of the price forecast. Thus, the near-term market quotes, blending period, long-term forecast, and the escalation period constitute the forecasted natural gas price curve for each of the relevant Western natural gas trading hubs. The natural gas price forecasts are provided in Technical Appendix FPP-1.

Power prices are derived by multiplying the forecasted gas prices and the forecasted market implied heat rate ("MIHR") defined as the ratio of power prices and the corresponding gas price for that market. The MIHR forecast for January 2022 through March 2025 is the ratio of 21-day average power price quotes from Argus and the 21-day average forward gas prices from Argus, as described above. The second part of the curve, from April 2025 to March 2027, reflects a blend of market heat rates based

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

on the market quotes and fundamental forecast. In the blending process, the MIHR based on pure market quotes are more heavily weighted in the initial period, with the MIHR based on the fundamental portion of the curve receiving greater weight towards the end of the blending period. The third part of the curve, from April 2027 until December 2051, is entirely based on the MIHR curve from the fundamental forecast. The power price forecasts are also provided in Technical Appendix FPP-1.

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

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

14. Q. DID THE COMPANIES CONSIDER THE IMPACT ON FUEL AND PURCHASE POWER PRICES DUE TO FUTURE REGULATION OF GREENHOUSE GAS ("GHG") EMISSIONS?

A. Yes, the Companies developed various Price Forecasts with the expectation that GHG emissions will be regulated. The approach is consistent with information the Companies provided the Commission in prior IRP filings (Docket No. 21-06001), an approach that reduces GHG emissions through an anticipated federal cap-and-trade program. The Companies have developed Price Forecasts for "Low-carbon," "Mid-carbon," and "High-carbon" GHG allowance prices, and applied them to the base case fuel price scenario. The Price Forecasts for the carbon price scenarios are in Technical Appendix FPP-1. The sensitivity cases evaluating the impact to fuel and purchased power costs are described in the Economic Analysis section sponsored by Mrs. Anita Hart.

15. Q. PLEASE DESCRIBE THE SOURCE FOR CARBON ALLOWANCE PRICES AND ITS IMPACT ON FUEL PRICES.

A. NERA developed the three carbon price trajectories (Low, Mid, and High) for GHG emission allowances under a federal cap-and-trade program that would begin in 2027. NERA also provided estimates of the changes to the prices of fuels that could occur under a potential GHG cap-and-trade program. The effects of Low, Mid and High carbon prices on fossil fuels are stated as annual percentage adjustments to wholesale fossil fuel prices. Details regarding development of the allowance prices and fossil fuel price adjustors are sponsored by Dr. David Harrison of NERA.

16. Q. PLEASE CLARIFY WHAT YOU DESCRIBE IN Q&A 14 AS THE EFFECTS OF LOW, MID, AND HIGH CARBON PRICES ON FOSSIL FUEL PRICES.

A. GHG regulation under the Low, Mid and High carbon price scenarios will change demand for coal and natural gas. Under a federal cap-and-trade regime, the Companies and other fossil-fueled power plant owners would account for their GHG emissions with corresponding carbon allowances. This requirement will lead electric companies to modify their fuel demands. These, and other market effects (*e.g.*, changes in demand from residential and commercial natural gas users), will lead to changes in wholesale fossil fuel prices.

The fossil fuel price changes estimated by Dr. Harrison do not reflect a direct addition of carbon allowance costs to fuel prices—*i.e.*, burdening fuel prices with a cost of carbon before they are burned in power plants—because the costs associated with GHG emissions are accounted for in the allowances used by each generating unit.

17. Q. PLEASE PROVIDE AN OVERVIEW OF THE METHODOLOGY USED TO CONSTRUCT THE GHG PRICE FORECAST SENSITIVITIES.

A. The "Mid-carbon," "High-carbon," and "Low-carbon" scenarios were considered under the base fuel and power price case to determine the effects of federal GHG regulations on the various alternative plans under consideration. Three conceptual steps were taken to compute net adjustments to the fundamental base fuel and purchased power price forecasts for each of the carbon sensitivities. First, the natural gas price forecasts were adjusted for the expected changes in fuel demands caused by GHG regulations. This was accomplished by applying the percentage adjustments to the commodity prices.

Second, once natural gas prices were adjusted for the respective carbon price scenario, purchased power price levels also were adjusted to reflect that gas prices are a key driver of power prices in the Western Electricity Coordinating Council. The second step was accomplished with spreadsheet computations that follow the same methodologies used to adjust on-peak and off-peak power prices in the high and low gas price cases.

Third, after purchased power prices were adjusted for changes in gas prices, the cost of carbon emissions reflected in NERA's first set of data output (carbon allowance prices) is added. The Companies prepared estimates of the potential increases to regional power prices (dollars per megawatt-hour) based off NERA's carbon allowance price forecasts (dollars per short-ton). In the last modeling step, these price increases are added to the "no-carbon" power price forecast. More information regarding the development of the carbon power price adders can be found in Section 4 of the Amendment.

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

A. WoodMac's regional power price forecast represents day-ahead firm energy prices, however, it does not explicitly include the full cost of new capacity additions that would be required to ensure resource adequacy over the forecast period. Therefore, the Companies prepare a capacity price forecast for market purchases to supplement the regional power price forecast from WoodMac. The regional price forecast is used by the

PROMOD model to economically dispatch market purchases against internal generation, while the capacity price forecast (dollars per kilowatt-year) is multiplied by the Companies' open capacity position as an additional fixed fuel and purchased power cost.

19. Q. HOW DID THE COMPANIES PREPARE ITS LONG-TERM CAPACITY PRICE FORECAST?

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

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

A. Yes, it does.

Statement of Qualifications

Zeljko Vukanovic **March 15, 2022**

Professional Experience

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

Develop and maintain proprietary perspective on regional gas and power market factors and fundamental price forecasts.

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

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

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

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

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

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

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

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

Education

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

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

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

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

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, ZELJKO G. VUKANOVIC, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

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

Date: March 18, 2022

ZELJKO G. VUKANOVIC

MARK WARDEN

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

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

First Amendment to the
2021 Joint Triennial Integrated Resource Plan (2022-2041)
Docket No. 22-03___

Prepared Direct Testimony of

Mark Warden

I. INTRODUCTION

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

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

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

A. I hold a Bachelor's Degree and a Juris Doctorate Degree. I have worked for the Companies for 11 years and in the energy industry for nearly 20 years. Details regarding my professional background and experience are set forth in **Exhibit Warden-Direct-1**.

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

A. I have not.

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

A. I sponsor the Companies' request for funds to support the investigation into permitting design and construction of a 1,000-megawatt ("MW") pumped hydro energy storage facility known as White Pine Pumped Storage Hydroelectric Energy Storage ("White Pine").

5. Q. WHAT EXHIBITS ARE ATTACHED TO YOUR TESTIMONY?

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

- **Exhibit Warden-Direct-1**, Statement of Qualifications

6. Q. WHAT MATERIALS ARE YOU SPONSORING?

A. I sponsor the following Technical Appendices:

- REN-10 PSH Pricing Analysis (Confidential)
- REN-11 White Pine Due Diligence

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

A. Yes. Technical Appendix REN-10 is confidential as it contains pricing details of comparable projects and studies that are not available in the public domain. Public disclosure of this information could allow a competitor to determine the confidential forecasts and assumptions, and may impact the Companies' ability to negotiate in the marketplace and obtain the best terms and pricing for their customers. Parts of my testimony reference the pricing details from confidential Technical Appendix REN-10 and, consequently, those values are redacted. Parts of my testimony also reference estimated costs associated with the development and operation of White Pine. The Companies are not requesting approval of those costs, or of the White Pine itself, with this filing and the estimated costs are being presented for informational purposes only. These cost estimates are third-party commercially-sensitive information, and the project costs are subject to the ongoing negotiations between the developer of the project and the Companies. Finally, while the Companies are publicly disclosing the $3.5 million amount necessary to move the White Pine project forward, the exact amount of the payment to the developer of the project to offset due diligence costs and for the Companies to receive exclusive rights to purchase the project should be confidential. The developer payment amount represents commercially-sensitive information and was arrived at as a result of confidential negotiations. Disclosure of such information may impair the Companies' ability to negotiate for the best terms in the future.

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

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

9. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF THE COMMISSION'S REGULATORY OPERATIONS STAFF ("STAFF") OR THE NEVADA ATTORNEY GENERAL'S BUREAU OF CONSUMER PROTECTION ("BCP") TO FULLY INVESTIGATE THE INFORMATION SET FORTH IN THIS FILING?

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

10. Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. In section II, I formulate the Companies' request to spend $3.5 million to perform the necessary due diligence and study the White Pine as well as describe the project.

II. WHITE PINE PUMPED STORAGE HYDRO

11. Q. BRIEFLY DESCRIBE THE REQUEST.

A. The Companies are requesting approval to spend $3.5 million to partner with a developer that is developing and performing due diligence on a pumped storage hydro project located in White Pine County, about eight miles north of Ely. The funding requested will be utilized in the following manner: [redacted] will be a payment to the developer of the project to offset costs of due diligence and for the Companies' exclusive rights to purchase the project if the project ultimately is determined to be viable. The remaining [redacted] will be funding that the Companies will use to confirm the due diligence that the developer is performing; as well as analyzing the way that the project will be utilized to maximize the benefit to the two service territories; verifying that the project achieves an acceptable cost of energy storage while minimizing the risk of integrating a large amount of

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renewables onto the system; paying for the legal fees that will be incurred for partnering or purchasing the project; performing community outreach activities; paying the engineering costs to assist in making design decisions, in order to maximize the benefit to the grid (e.g. should the turbines be fixed speed or variable speed); paying for project management and managerial costs; and other miscellaneous expenses. Through this due diligence, the Companies will determine if any fatal flaws to the project exist, and whether the project can be successfully and economically integrated into the system for the benefit of customers. If the due diligence does not identify any fatal issues with the project and it is determined the project provides customer benefits, then the Companies will request further Commission approval to complete the final due diligence studies, and the funding to complete preliminary engineering and approval to acquire the project. By taking a stepped approach, the Companies seek to ensure the project is properly planned and developed and that it is managed in a way that reduces financial risk and increase likelihood of a commercially viable project. The funds requested will allow the Companies to actively participate and review this first stage of diligence and design, which is intended to identify any fatal flaws at the selected site or in the design. In addition, the funds provide the Companies the exclusive right to acquire the project should the diligence confirm a viable project.

12. Q. WHY ARE THE COMPANIES CHOOSING TO EXPLORE PUMPED STORAGE HYDRO?

A. Long-duration, utility-scale storage is essential to diversify the Companies' energy storage portfolio, help integrate increasing amounts of solar energy on the system, and to prepare for other potential intermittent renewable projects. These intermittent renewable resources are mostly solar. The Companies' peak load is in the hours after the sun sets and solar resources are not available. Storage solutions are essential to continue to supply the Companies' customers in these evening hours with renewable resources. Until recently, pumped storage was virtually the only form of utility-scale energy storage used around the world. Other long-duration energy storage technologies are generally only at the demonstration or research and development stage and do not provide commercially viable storage solutions at this time. Pumped storage hydro is a proven long-duration, utility-scale storage solution. Ninety-four percent of utility-scale energy storage in the United States is pumped storage hydro, represented by 43 plants with a capacity of 21.9 gigawatts.[1] The long-life cycle of a pumped storage hydro project (likely from 50 to 100 years or more) would provide long-duration, utility-scale storage solutions for years to come and as the Companies integrate greater amounts of solar resources. Another benefit of pumped storage hydro is it puts real spinning mass, in the form of traditional hydro generators, on the grid. Traditionally, this provides inertia for the grid for improved system stability. This same spinning mass is not present in inverter-based resources, including chemical battery storage. NV Energy continues to monitor improvements in inverter-based technologies and facilities, including the ability to support system stability through settings and controls. Thus, in the long-run, taking a portfolio approach to storage and having some inertial resources and some inverter-based resources will create greater grid stability.

13. Q. WHY DID THE COMPANIES PARTNER WITH rPLUS ENERGIES?

A. rPlus Energies' ("rPlus") White Pine is the most developed pumped storage hydro project in Nevada. In addition, rPlus has significant experience in developing pumped storage hydro projects. White Pine was originated by

[1] U.S. Department of Energy, Water Power Technologies Office, U.S. Power Market Report, January 15, 2021.

Gridflex Energy, which in 2019 entered into a partnership with rPlus to form rPlus Hydro. Gridflex, and later rPlus, approached NV Energy about the project. rPlus has been involved in U.S. pumped storage development since 2009. rPlus has worked on solar PV projects and the permitting and engineering phase of pumped storage hydro projects, which has given them the understanding needed for site selection, development realities, hydro engineering, project management, permitting and design for this project. rPlus also has developed relationships with the leading original equipment manufacturers of pumped storage equipment, and engineering, procurement and construction contractors, which are highly specialized firms. Participation of these specialized firms early in the design and development process will be critical to reduce costs and assure a well-engineered project. This is in part due to the challenges in obtaining financing for a project with such long lead times, complicated siting issues and the long lead time to permit and construct a facility, which can be from 5-10 years (the Federal Energy Regulatory Commission ("FERC") permitting of 3 years and construction of about 5 years). It is also worth noting that, prior to the recent widespread adoption of intermittent renewable resources, utilities had less need for long-duration storage.

rPlus has already financed and managed several of the fundamental aspects of the development of White Pine, including securing a source of fill and make-up water, establishing an interconnection queue position, and moving the project through several of the requisite sequences of development-phase engineering, permitting, and licensing.

rPlus has filed and obtained a preliminary permit and filed a draft license application with FERC.

14. Q. BRIEFLY DESCRIBE THE PROJECT AND DESCRIBE WHY IT IS A GOOD LOCATION FOR A PUMPED STORAGE HYDRO PROJECT.

A. White Pine is a 1,000 MW closed-loop pumped hydro storage system that would be capable of discharging over eight hours. Figure REN-9 in the narrative, Section 6, depicts a typical pumped storage hydro project. The site is just south of the town of McGill and to the east of Highway 93. The physical attributes and the operating capabilities of the project are described in the first three paragraphs of the narrative for the White Pine that can be found in Section 2.D.B.3 of this filing. Below are reasons why the location was chosen and why it is a good fit for the grid.

The project will have a 2,270-foot vertical drop headrace, which allows for a compact project and excellent generation profile. The upper reservoir is 65 acres and the lower reservoir is 90 acres, thus, there is a significant power output from a very compact footprint. The powerhouse will consist of three 333 MW generators. These characteristics provide for high MW/acre ratio. The project will interconnect at the Robinson Summit Substation, which allows the project to distribute power, or be charged from either Sierra's or Nevada Power's service territory upon the completion of the Greenlink Nevada projects and utilizing the existing One Nevada Transmission line path. This provides flexibility to use the system to achieve the greatest benefit to whichever system has the greater need on a real-time basis. There are not many locations in either service territory where a 1,000 MW energy storage system could interconnect, and the Greenlink Nevada and One Nevada Transmission lines have enough capacity to be utilized by the Companies for the benefit of their customers. The 1,000 MW of energy storage will be utilized by both service territories, and, if this project moves forward, it is envisioned that it would complement and diversify the energy storage that is identified as being needed in the 2021 Joint Integrated Resource Plan's ("IRP") Preferred Plan that was recently approved by the Commission.

15. Q. BRIEFLY DESCRIBE ANY SIGNIFICANT AREAS OF CONCERN FOR THE PROJECT AND DESCRIBE HOW THEY HAVE BEEN RESOLVED.

A. Essential to the success of any pumped storage hydro project is a source of water. rPlus has worked with White Pine County to secure a water resource for the initial fill of the reservoir, and make-up water for the project. The existing water rights that would be allocated to this project were originally allocated to White Pine County for industrial use and economic development. Once the project is initially filled with water, because it is closed loop and continuously reuses the water supply, it will use about 560 acre-feet[2] of annual make-up water. To put this in context, that is less water than a single 140-acre alfalfa field which represents one agricultural pivot.[3] No natural water courses or streams are affected by the construction of the project.

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[2] rPlus Federal Energy Regulatory Commission Draft Application for Original License, Unconstructed Project, FERC Project No 14581.
[3] Based on 476 acre-feet in a season for 140 acres of alfalfa.

Potential opposition from local stake holders has not materialized to date. rPlus has been working with the local Native American tribes in the area, and they have not expressed any concerns with the project location or use of resources.

Environmentally, the project is located on land administered by the Bureau of Land Management ("BLM"). rPlus has been working with the BLM to identify and mitigate any environmental issues created by the project. These issues would all be addressed through the environmental impact statement process that would be facilitated by the BLM. That said, the scope of environmental impact is certainly lessened by the total project area being just over 150 acres.

16. Q. WHAT ARE THE KEY RISKS FOR THE PUMPED STORAGE HYDRO PROJECT?

A. Hydro-electric dams have produced electricity for well over a century, so the technology is well understood, and the long-term performance well established. The biggest risk to the project is whether the geotechnical features of the selected site support the underground tunnels to be used for the power house and the headrace tunnel. These issues will all be researched through the proposed due diligence being requested in this application.

17. Q. CAN YOU PROVIDE A COST COMPARISON BETWEEN THE DIFFERENT BULK STORAGE TECHNOLOGIES?

A. Known and reliable long-duration energy storage technologies are limited to pumped storage hydro, lithium-ion batteries, and compressed air anergy storage

(“CAES”). CAES projects require unusual underground geology (the only two plants operating in the world use salt domes), and the Companies are unaware of any CAES projects currently being explored in Nevada. Although this technology is slowly making progress at this time, the last commercial-scale CAES project constructed in the world was a 110 MW plant that became operational in 1991, making a comparison difficult with that technology. Recent figures indicate a per-kilowatt (“kW”) cost equivalent to that of pumped storage hydro, and a project lifespan of 35-40 years. With life extension projects, a pumped storage hydro can be operational for over 75 years. As the technology is so similar to a hydroelectric dam, this lifecycle is similar to that seen in the Hoover Dam project.

Several demonstration and pilot energy storage systems have been marketed to the Companies, but they are not yet commercially viable at a utility scale.

Although direct cost comparison between BESS and pumped storage hydro is problematic, the two technologies operate on similar costs metrics. In NV Energy’s 2021 Joint IRP filing, the Companies included a 66 MW BESS with 4 hours of storage installed in 2023 for three projects. The cost of that BESS was approximately $101 million, or $1,530/kW, or a per-kilowatt-hour (“kWh”) capital cost of $382/kWh. White Pine has an estimated capital cost of approximately [redacted] and will have a lifespan of 75 years or more. In the comparison reflected in Table REN-6 of the narrative, the initial cost to install a PSH project is high compared to batteries on a dollar per kW basis but is a lower cost alternative on a dollar per kWh basis, making it a suitable resource for shifting the delivery of large amounts of intermittent renewables to the peak.

Utility-scale BESS estimates for fixed O&M costs range up to $15-20/kW per year when augmentation (maintenance of full storage capacity) is included. Pumped storage hydro is estimated at [redacted] year fixed O&M.

Technical Appendix REN-10 provides a cost comparison summary between White Pine and a theoretical 8-hour BESS system. Most BESS systems being installed today have storage durations of two to four hours. The theoretical BESS system in Technical Appendix REN-10 was analyzed with an eight-hour duration to match White Pine's duration. Besides duration differences, BESS and pumped hydro technologies have vastly different life spans. The Companies' experience suggests 20 years is a good assumption for BESS life. These compare with a lifespan of 60 years and up to 100 years with life extension activities for pumped storage. Both technologies in Technical Appendix REN-10 were analyzed using a 60-year lifespan, which means the BESS systems would have to be replaced twice.

An Investment Tax Credit ("ITC") may be a factor in project economics as well. Unlike a solar-paired BESS, a standalone BESS does not currently qualify for an ITC. Pending federal legislation includes a 30 percent ITC for standalone energy storage that would apply to both pumped storage and BESS systems.

When it comes to efficiency, White Pine is estimated to have a round-trip efficiency of 77 to 80 percent. A typical BESS has a higher round-trip efficiency ranging from 85 percent to 90 percent depending on site and project specifics. However, BESS will incur some efficiency degradation through cycling, while White Pine will not. Given the low cost of energy that would be used for charging White Pine, the difference in efficiency between White Pine and BESS systems is expected to be negligible.

With the inputs and assumptions in place, Technical Appendix REN-10 demonstrates [redacted] net present value cost for White Pine, as analyzed, and between [redacted] net present value cost for BESS technology, as analyzed. These net present value costs are based on the full life of the projects in contrast to the values reflected in Table REN-6 of the narrative, which compares installed costs in dollars per kW and dollars per kWh between proposed and approved BESS and the White Pine.

18. Q. THE COMMISION DENIED THE COMPANIES' REQUEST FOR $150,000 IN DOCKET NO. 10-02009 TO STUDY THE VIABILITY OF ADDING PUMPED STORAGE HYDRO TO THE SYSTEM. WHAT HAS CHANGED SINCE THEN AND HOW IS THIS REQUEST DIFFERENT FROM THAT REQUEST?

A. In Docket No. 10-02009, the Companies requested approval for $150,000 to perform a preliminary examination of using pumped storage in Nevada and performing a preliminary feasibility study on up to four sites that were identified. The Commission denied the request because the Companies did not identify the specific need for the pumped storage hydro project.[4] In addition, the Commission posited that fast start combustion turbines could support the intermittency of renewables better than a storage system could and that the proposed budget of $150,000 was inadequate for the stated purpose of studying pumped hydro storage opportunities.[5]

[4] Docket No. 10-02009, July 30, 2010, Order at 22.
[5] *Id*. at 22-23.

The Companies' resource mix, as well as the legislative and regulatory environment under which the Companies operate, has significantly changed in the decade since this initial request was presented. Today, the Companies have significantly greater intermittent resources as part of their generation mix. In fact, since the 2010 IRP filing, the Companies have contracted for more than 3,200 MW of solar. These intermittent resources by their nature require storage solutions that will optimize these assets and allow for the reliable supply of energy during hours when the sun does not shine and the wind does not blow. Further, the state's 2050 clean energy goal cannot be fulfilled by adding large amounts of gas-fired resources to solve the intermittency. Therefore, long-term storage, of a duration greater than four hours is needed to provide grid stability and meet peak demand. Pumped storage hydro is currently the only proven storage solution that meets this requirement. Pumped storage hydro remains the largest grid energy storage solution operating in the United States, according to the Electric Power Research Institute.[6] Pumped storage hydro also provide essential ancillary services necessary for the stable and reliable operation of the grid.[7] These ancillary services are available over a longer period of time in the case of White Pine versus other storage solutions such as batteries that are of shorter duration, typically four hours. Critically, pumped storage hydro can provide ancillary services such as system inertia, frequency regulation, spinning reserves, black start and reactive power. These ancillary services become more critical to a reliable grid as the number of intermittent resources are added. Accordingly, the addition of long-term storage, such as White Pine, is necessary to the long-term

[6] EPRI 2019 Report: Pumped Storage Hydro in Resource Planning in The United States: A Survey of Recent Results and Methods.
[7] National Hydropower Association, *Pumped Storage*, available at https://www.hydro.org/policy/technology/pumped-storage/.

viability of a clean-energy system based on high percentage of intermittent renewable generation, a system that is far different than the one in 2010.

19. Q. DESCRIBE THE DUE DILIGENCE THAT HAS ALREADY BEEN COMPLETED ON THE PROJECT.

A. rPlus has applied to the BLM for a use permit and begun preliminary design for the project. rPlus has also filed a Draft License Application with FERC, which will be the lead agency for completing an environmental impact statement, with the BLM and other cooperating agencies assisting with the process. A pumped storage hydro project is customized to each site, and rPlus is in the process of working with an engineering firm and original equipment manufacturer to make an optimal design. rPlus has indicated that they have spent approximately [redacted] getting the project to the FERC draft licensing phase and in the Development Agreement will commit to spend up to [redacted]. rPlus has performed some due diligence activities, which have not uncovered any fatal flaws with the project and include initial drilling for geotechnical analysis of the lower reservoir. rPlus intends to perform further geotechnical drilling for the headrace and lower reservoir and seismic studies in the course of 2022. The next step of the development is for rPlus to finalize the permitting for the project, to contract with an engineering firm for later stage engineering, and to contract the manufacturing and design of the pump-turbine components. rPlus is committed to spend up to [redacted] to get to this advanced stage of permitting and engineering.

20. Q. PLEASE EXPLAIN WHY THE WHITE PINE PROJECT WAS SELECTED OVER OTHER POTENTIAL PUMPED STORAGE HYDRO PROJECTS IN THE REGION.

A. NV Energy is aware of other potential pump storage hydro projects in the region; however, White Pine is more advanced than any other project in the state, having obtained water rights, pursuing right-of-way grants with the BLM, filed its draft application to construct and operate the facility with FERC and has an executed Large Generator Interconnection Agreement for 1,000 MW. In addition, the proximity to transmission and interconnection as discussed above and the compact low impact footprint of the site makes White Pine a favorable site.

21. Q. PLEASE SUMMARIZE THE KEY PROJECT MILESTONES AND THEIR TARGETED TIMELINE TO COMMERCIAL OPERATION.

A. rPlus has indicated a commercial operation date of 2030 for White Pine. The filing of the draft application period initiates an approximately two-year period of comment and review by the FERC, once approval is received (which is anticipated to be in the first quarter of 2024) construction can begin on the project, which would have a duration of approximately five years. During the FERC approval process, design and site due diligence would continue including the engagement of engineering procurement and construction contractors and the selection of a turbine supplier. Because of the very custom nature of pumped storage hydro projects, early engagement of contractors and suppliers is critical to a cost-effective and successful design.

22. Q. PLEASE SUMMARIZE HOW THE COMPANIES ARE TRACKING AND ACCOUNTING FOR THE PROJECT COSTS.

A. The Companies have established specific identification numbers to track costs which are being tracked as they are incurred.

23. Q. PLEASE SUMMARIZE THE STUDY COSTS INCURRED AS OF JANUARY 31, 2022.

A. As of this date, $214,540 has been spent by the Companies on legal fees and a third-party engineering review of the work that was completed by rPlus.

24. Q. PLEASE DESCRIBE WHY THE INCURRED COSTS WERE SPENT PRIOR TO THE COMMISSION APPROVAL.

A. The Companies incurred expenses to take timely action on the available opportunity with the developer before the resource was committed to another party. Opportunities arise that require timely investigation and evaluation. The expenditure of funds to date has in fact put the Companies in the position to be able to request funds to perform further diligence on this specific pumped storage project.

25. Q. PLEASE SUMMARIZE THE STUDY COSTS PLANNED FOR 2022-2024 AND ELABORATE ON THEIR NEED TO SUPPORT THE ABOVE PROJECT DEVELOPMENT MILESTONES.

A. NV Energy will use the funds requested for the ongoing support of efforts to perform geotechnical drilling, seismic evaluation and the verification of those efforts.

26. Q. PLEASE SUMMARIZE THE COMPANIES' REQUESTS WITH REGARDS TO WHITE PINE.

A. The Companies propose that the Commission approve Sierra's request to approve the total study costs of $3.5 million. Specifically, the Companies request this funding for:

1) Funding for due diligence to perform seismic and geotechnical analysis;
2) Confirmatory diligence of rPlus reports;
3) Legal fees; and
4) Preliminary design analysis.

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

A. Yes, it does.

MARK WARDEN
DIRECTOR, RENEWABLE SOURCING

Mark is responsible for leading the companies' efforts to identify, acquire, and develop renewable energy and storage projects for the Company to own.

Professional Experience

Mark joined NV Energy's legal department in 2010 as an Assistant General Counsel and most recently as Sr. Counsel and Assistant Secretary. Mark has supported a number of areas for the company, including procurement, resource optimization, generation, risk and renewables. In July of 2021 Mark accepted the position of Director, Renewables Sourcing. Among other activities Mark has:

- Negotiated and drafted contracts for Hot Pot and Iron Point Solar/Storage projects
- Revised and negotiated energy trading agreements for gas and power
- Negotiated and drafted renewable power purchase agreements
- Performed due diligence on renewable project development
- Negotiated and drafted agreements for the acquisition of power plants

Education
Juris Doctorate – University of Utah, S.J. Quinney College of Law, Salt Lake City, Utah ▪ 1996
Bachelor of Arts – Brigham Young University ▪ 1993

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, MARK WARDEN, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

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

Date: March 18, 2022

MARK WARDEN