BEFORE THE

PUBLIC UTILITIES COMMISSION OF NEVADA

IN THE MATTER of the Application of NEVADA POWER COMPANY, d/b/a NV Energy, filed pursuant to NRS 704.110 (3) and (4), addressing its annual revenue requirement for general rates charged to all classes of customers.	)))))	Docket No. 23-06___

NEVADA POWER COMPANY
d/b/a NV Energy

VOLUME 7 of 24

Recorded Test Year ended December 31, 2022
Certification Period ended May 31, 2023
Expected Change in Circumstance Period ending December 31, 2023

MATHEW J. JOHNS

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 23-06___
2023 General Electric Rate Case

Prepared Direct Testimony Of

Mathew J. Johns

Revenue Requirement

SECTION 1: INTRODUCTION

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

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

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

A. I hold a Bachelor of Science Degree in Civil Engineering and Master of Science Degree in Agricultural Engineering. From 1996 through 2015, I worked on site cleanup and remediation projects nationwide as an environmental engineer, project manager and program manager for global engineering consulting firms.

Prior to joining the Companies in 2015, I worked for the engineering firm CH2M Hill. In 2008, CH2M Hill was selected as the Owner's Engineer and Construction

Management ("OECM") firm assigned to the Reid Gardner Generating Station ("Reid Gardner"). As project manager for the assignment, I primarily focused on Reid Gardner pond closure, Mesa Pond construction, and landfill expansion activities, including planning, permitting, engineering and construction oversight services. Beginning in 2011, I supported the Company throughout the negotiation of the Environmental Agreement ("EA") between Nevada Power and California Department of Water Resources ("CDWR") for environmental work at Reid Gardner under the Administrative Order and Consent ("AOC") with the Nevada Division of Environmental Protection ("NDEP").

In 2015, I joined the Companies as Director, Environmental Remediation and Resource Development, with primary responsibility for managing the Companies' Regulatory Assets and Asset Retirement Obligations ("AROs") for Energy Supply, including decommissioning, demolition, and environmental remediation of the Companies' retired generating facilities. I was also the Companies' representative for generating facility joint partnerships.

In 2022, I assumed the role of Vice President, Environmental Services and Land Management and continue to be responsible for site closure activities related to Reid Gardner, Navajo Generating Station ("Navajo"), and Mohave Generating Station ("Mohave"). My statement of qualifications is attached as **Exhibit Johns-Direct-1.**

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3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS VICE PRESIDENT ENVIRONMENTAL MANAGEMENT AND LAND SERVICES.

A. I lead a group of directors, managers, engineers, environmental scientists, and land resource professionals who perform or direct environmental analyses, specialty studies, and other tasks necessary for obtaining regulatory approvals and land rights for utility projects. My departments are responsible for compliance and permitting pertaining to environmental and land resource matters for the Companies' facilities.

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

A. Yes. I testified before the Commission in Nevada Power's 2017 General Rate Case ("GRC"), Docket No. 17-06003 and provided testimony in Nevada Power's 2020 GRC, Docket No. 20-06003.

I also provided testimony related to the North Valmy Project agreements in the Second Amendment to the Companies' 2018 Joint Integrated Resource Plan, Docket No. 19-05003, and supplemental testimony related to land, environmental, and water permits for the Companies' merger application, Docket No. 22-03028.

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

A. I am supporting the reasonableness of costs incurred for Mohave from June 1, 2020, through December 31, 2022 (the "Test Period"), Navajo from December 2019 (the end of operations) through the end of the Test Period, and Reid Gardner through the end of the Test Period. The expected costs for Mohave, Navajo, and Reid Gardner activities through May 31, 2023 (the "Certification Period") are also presented. These costs are found in the following H-CERT schedules:

- H-CERT-28 Mohave Generating Station Closure and Decommissioning Costs Regulatory Asset;
- H-CERT-31 Navajo Generating Station Retirement Regulatory Asset; and
- H-CERT-30 Reid Gardner 1-4 Generating Station Decommissioning and Remediation Regulatory Asset.

6. Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes, I am. I sponsor the following exhibits:

- **Exhibit Johns-Direct-1**, Statement of Qualifications
- **Exhibit Johns-Direct-2,** Navajo Generation Station Closure Costs Without Carrying Charges
- **Exhibit Johns-Direct-3**, Administrative Order on Consent
- **Exhibit Johns-Direct-4**, Environmental Agreement
- **Exhibit Johns-Direct-5**, Reid Gardner Station Site Closure Elements
- **Exhibit Johns-Direct-6**, Reid Gardner Station Decommissioning Costs Without Carrying Charges
- **Exhibit Johns-Direct-7**, Reid Gardner Station Remediation Costs Without Carrying Charges
- **Exhibit Johns-Direct-8**, Reid Gardner Station Site Map

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

A. No.

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8. Q. HOW IS THE REMAINDER OF YOUR TESTIMONY STRUCTURED?

A. In Section II, I provide information regarding the former Mohave ongoing site costs included in H-CERT-28. In Section III, I address the former Navajo costs included in H-CERT-31. In Section IV, I provide general information regarding Reid Gardner decommissioning and remediation. In Section V, I address costs related to the decommissioning and demolition work completed at Reid Gardner. In Section VI, I address costs related to waste management facility closure work completed at Reid Gardner. In Section VII, I summarize the potential source and work completed to address soil and groundwater impacts, and the associated costs for remediation activities at Reid Gardner. In Section VIII, I address prior estimates and current estimates of future costs for the decommissioning, demolition, and remediation at Reid Gardner.

SECTION II: H-CERT-28 MOHAVE GENERATING STATION CLOSURE AND DECOMMISSIONING COSTS REGULATORY ASSET

9. Q. WHAT IS THE CURRENT STATUS OF MOHAVE?

A. Nevada Power is a 14 percent owner in the project. Southern California Edison (majority owner and operator) and Los Angeles Department of Water and Power ("LADWP") (who has assumed Salt River Project's original ownership share) are the other owners on the project. Mohave decommissioning concluded in 2013, however, there are continued costs for ongoing site maintenance and monitoring activities associated with the closed onsite landfill, monitor wells, site storm water controls (e.g., erosion), site security (e.g., fence repairs), and Southern California Edison's oversight costs. The costs also include property insurance and associated taxes experienced between GRCs.

As shown in H-CERT-28, Nevada Power's share of the ongoing site cost for Mohave through the Test Period is $205,000 and the forecasted cost for these activities during the Certification Period is $37,000. No carrying charges are applied to the Mohave closure.

10. Q. HOW WILL NEVADA POWER RECORD FUTURE MOHAVE CLOSURE COSTS?

A. Future costs will continue to be recorded in the Commission-approved regulatory asset and presented for recovery in Nevada Power's next filed GRC.

11. Q. WHAT IS THE STATUS OF THE MOHAVE LAND?

A. The property has been marketed for sale since 2016. The owners continue to engage with a third party that expressed interest in 2018 on a potential land sale. Since that time, Southern California Edison sought and received California Public Utilities Commission confirmation in September 2020 that the sale would not be subject to California Section 851 land transfer requirements. In May 2022, Clark County approved a waiver of development standards as part of re-parceling the property to affect the sale of up to approximately 2,000 acres.

If, and when, a transaction occurs and it is material, the net gains would be included in a future GRC for the benefit of Nevada Power's customers. The owners will continue to retain approximately 500 acres of land and post-closure care associated with the closed onsite landfill.

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SECTION III: H-CERT-31 NAVAJO GENERATING STATION RETIREMENT REGULATORY ASSET

12. Q. PLEASE DESCRIBE NAVAJO.

A. Navajo was a 2,250-megawatt, coal-fired, steam-electric generating plant with three operating units. The plant is located on the lands of the Navajo Nation near Page, Arizona. The three generating units became operational in 1974, 1975, and 1976, respectively. Nevada Power is an 11.3 percent participant in the plant. Arizona Public Service, LADWP, Salt River Project, and Tucson Electric Power are other participants in the plant, with Salt River Project also holding an interest in Navajo on behalf of the United States.

In 2017, the participants elected to cease operation of the plant on or before December 22, 2019, the date which the original lease agreement with the Navajo Nation would terminate. To facilitate the participants' obligations to close, decommission and remediate the plant site after this termination date, an Extension Lease Agreement ("Extension Agreement") was negotiated with the Navajo Nation in 2017. The Extension Agreement was submitted to the Commission in the Company's Third Amendment to its Emission Reduction and Capacity Replacement ("ERCR") Plan in 2017.[1]

13. Q. WHEN DID NAVAJO RETIRE?

A. Navajo ceased operations after the onsite coal supply was depleted on November 18, 2019.

[1] Docket No. 17-11005.

14. Q. WHAT STATUTORY AND REGULATORY REQUIREMENTS AFFECT THE RETIREMENT OF NAVAJO?

A. In 2013, the Nevada Legislature passed Senate Bill 123, which required the early retirement of 800 megawatts of coal-fired generation in southern Nevada in the years 2014, 2017 and 2019.[2] Senate Bill 123 also required that the Company prepare an ERCR Plan for the Commission, which in part included the cost estimates for decommissioning, demolition, and remediation at Navajo. The Commission approved the ERCR Plan in Docket No. 14-05003 on October 28, 2014, and issued an order requiring the elimination of Nevada Power's coal-fired generating capacity at Navajo on or before December 31, 2019. In the Third Amendment of the ERCR Plan in Docket No. 17-11005, the Commission approved the retirement of Navajo on or before December 31, 2019, and recovery of associated costs resulting from its retirement.

15. Q. PLEASE DESCRIBE WHAT NAJAVO COSTS WERE RECOVERED IN THE 2020 NEVADA POWER GRC.

A. Nevada Power recovered the remaining undepreciated net book value, stranded inventory cost, Navajo shut down costs incurred as of November 2019, and the Coal Supply Final Global Cost Allocation and Mutual Release along with true-up costs, as part of the stipulated settlement approved by the Commission for the 2020 Nevada Power GRC, Docket No. 20-06003.[3,4] The total amount of these costs was $31.07 million. No carrying charges were assigned to these costs that were incurred at the time of plant retirement. Any adjustments to stranded inventory occurring

[2] Senate Bill 123 is codified in the Nevada Revised Statutes ("NRS") §§ 704.7311 to 704.7322.
[3] The Company elected to defer the demolition phase costs incurred from December 2019 through May 2020 until the next general rate case to allow for a more complete review of demolition phase activities subsequent to the end of operations in November 2019.
[4] Docket No. 20-06003, January 28, 2021, Modified Final Order, Attachment 1, p. 6.

during decommissioning (i.e. materials returned to inventory) were noted to be included as part of decommissioning costs as part of the next GRC.

In accordance with the Commission order from the Company's 2017 GRC, Docket No. 17-06003, Nevada Power also netted a credit for the avoided operation and maintenance expense and depreciation expense for the year 2020 that resulted from the retirement of the plant in 2019.[5] This credit amounted to $32.22 million with carrying charges.

Therefore, the total regulatory assets costs and regulatory liability credits for avoided costs in 2020 resulted in a net credit of $1.15 million. These costs were amortized over a three-year period.

16. Q. PLEASE DESCRIBE WHAT NAJAVO COSTS HAVE BEEN INCURRED SINCE THE 2020 NEVADA POWER GRC.

A. As shown in H-CERT-31, Nevada Power's share of Navajo closure costs incurred through the Test Period is $17.25 million and the forecasted cost for these activities through the Certification Period is $2.49 million, excluding carrying charges.

The total amount of carrying charges incurred from through the Test Period are $2.27 million. Forecasted carrying charges during the Certification Period, are $0.64 million.

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[5] Docket No. 17-06003, December 29, 2017, Final Order, p. 71.

These costs are further discussed in the remainder of this section. **Exhibit Johns-Direct-2** further categorizes Nevada Power's share of Navajo closure costs from December 2019 to December 2022, excluding carrying charges.

17. Q. PLEASE SUMMARIZE THE NAVAJO DECOMMISSIONING ACTIVITIES COMPLETED AS OF DECEMBER 2022 AS WELL AS THOSE THAT WILL BE COMPLETED THROUGH THE END OF THE CERTIFICATION PERIOD.

A. As of December 2022, site decommissioning, decontamination, and demolition of the power block and most associated facilities, and asset recovery is complete. Removal of the railroad catenary system (i.e., electric power system) and removal of remedial action schedule schemes ("RAS") on the southern and western Navajo transmission system are also complete. Site civil earthwork activities related to pond salt consolidation and closures, landfill geomembrane and soil cover system closure, removal of support facilities and final site restoration activities (e.g. seeding of selected areas) are expected to be complete by December 2023, and prior to the end of the Navajo retirement deadline of December 22, 2024, as set out in the Extension Agreement.

Exhibit Johns-Direct-2, lines 6, 13, 19, and 41**,** summarize Nevada Power's share of these Navajo costs through the Test Period.

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18. Q. WHAT ARE THE SITE SERVICES AND SITE MONITORING COSTS AT NAVAJO?

A. Ongoing site support services include utilities, temporary power, site security, water supply, and similar support functions, project oversight and planning necessary to maintain site control, compliance with permit requirements (e.g. landfill wells and monitoring) and supporting decommissioning, decontamination, and demolition activities. Many of the ongoing site costs will diminish with physical work complete; however, activities such as maintenance of restored areas and post-closure care and groundwater monitoring of the closed ash landfill will continue through the Navajo Site Remediation Period ending December 22, 2054.

Exhibit Johns-Direct-2, line 26**,** summarizes Nevada Power's share of these Navajo costs through the Test Period.

19. Q. PLEASE SUMMARIZE OTHER ACTIVITIES AND OBLIGATIONS COMPLETED AS OF 2022 AS WELL AS THOSE THAT WILL BE COMPLETED THROUGH THE END OF CERTIFICATION PERIOD.

A. In accordance with the Extension Agreement, annual lease payments to the Navajo Nation began in December 2019 and will continue through December 2054. A total of $0.91 million for Nevada Power's share of lease payments have been incurred as of December 2022.

The Extension Agreement also includes a costs schedule for an asset retention payment to the Navajo Nation, reflecting demolition cost savings by the owners, for structures and facilities selected by the Navajo Nation to be retained for its future use. Nevada Power's share of the payment was $2.07 million. Most of the

asset retention payment was for the 80-mile Black Mesa & Lake Powell railroad from the plant to the former coal mines serving the plant, excluding the catenary system. Other retained assets were typically existing buildings, such as the warehouse, to remain for future use by the Navajo Nation. The assets retained by the Navajo Nation are turned over in an as-is condition, with no further obligations from the Navajo participants. There are no further retained asset obligations associated with the Extension Agreement.

In addition to the asset retention described above, Nevada Power incurred $0.2 million for its share of Navajo employee retention payments. These payments were associated with the retaining staff to end of operation and support shut down of Navajo in November 2019. Nevada Power recovered prior retention payments as part of the stipulated settlement approved by the Commission for the 2020 Nevada Power GRC, Docket No. 20-06003.[6]

Exhibit Johns Direct-2, line 46**,** summarizes the extension lease rent payments, asset retention payment, and employee retention costs through the Test Period.

20. Q. PLEASE SUMMARIZE ANY TRUE-UP ACTIVITIES AND OBLIGATIONS COMPLETED AS OF 2022 AND THOSE THAT WILL BE COMPLETED THROUGH THE END OF CERTIFICATION PERIOD.

A. **Exhibit Johns-Direct-2**, line 55 summarizes true-up activities, which include true-up of diesel inventory, stranded materials and supplies inventory, coal inventory, Salt River Project invoice adjustments prior to shut-down, a credit from a 2017-2019 Navajo Loadings audit, and the Company's external contractor support for

[6] Docket No. 20-06003, Jan. 28, 2021, Modified Final Order, Attachment 1, p. 6.

Navajo administration in 2019-2020. These activities result in a net credit of $0.14 million.

21. Q. WHAT ARE THE CURRENTLY FORECASTED FUTURE COSTS TO COMPLETE NAVAJO?

A. Nevada Power's currently forecasted costs for years 2023 – 2054 amount to approximately $20 million, with $11.3 million of that total from annual Extension Agreement lease payments. Future costs will continue to be recorded in the Commission-approved regulatory asset and presented for recovery in Nevada Power's next filed GRC.

22. Q. WHAT IS THE ANTICIPATED SCHEDULE FOR NAVAJO DECOMMISSIONING?

A. In accordance with the Extension Agreement, decommissioning of the plant and closure of the ponds, landfill, and associated facilities are expected to be completed by the end of 2023, prior to the Extension Agreement retirement period timeline of December 22, 2024. The site remediation period continues through December 22, 2054, as conditions require.

SECTION IV. H-CERT-30 – REID GARDNER DECOMMISSIONING AND REMEDIATION GENERAL INFORMATION

23. Q. PLEASE DESCRIBE REID GARDNER.

A. Reid Gardner was a 557-megawatt, coal-fired, steam-electric generating plant with four operating units. Units 1, 2 and 3 went into service in 1965, 1968, and 1976, respectively. Units 1, 2, and 3 each produced 100 megawatts using Foster Wheeler boilers and General Electric ("GE") turbine generators. Unit 4 went into service in

1983, producing 257 megawatts using a Foster Wheeler boiler and Westinghouse turbine generator. Units 1, 2, and 3 were retired in December 2014 and Unit 4 was retired in March 2017.

Supply water for generation was from Company-owned water rights and leased water rights. Wastewater generated from plant operations was primarily from air emission control systems (i.e. scrubbers), blowdown water from cooling systems, and blowdown water from ash handling systems, plant drains and sumps. Wastewater was managed onsite in wastewater evaporation ponds. Non-liquid wastes generated from coal combustion were managed in the onsite landfill.

24. Q. WHAT STATUTORY AND REGULATORY REQUIREMENTS AFFECT THE RETIREMENT OF REID GARDNER?

A. As discussed in Q&A 14 above, in 2013, the Nevada Legislature passed Senate Bill 123, which required the early retirement of 800 megawatts of coal-fired generation in southern Nevada in the years 2014, 2017 and 2019. The Commission approved the ERCR Plan in Docket No. 14-05003 on October 28, 2014, and issued an order that called for the retirement of Reid Gardner Units 1, 2 and 3 on or before December 31, 2014, and Reid Gardner Unit 4 on or before December 31, 2017.[7] The Commission's order in the Second Amendment to the ERCR Plan, Docket No. 16-08026, allowed for the retirement of Reid Gardner Unit 4 when it had burned its remaining coal reserve, which was depleted on March 11, 2017[8].

[7] Docket No. 14-05003, December 18, 2014, Final Order, p. 21.
[8] Docket No. 16-08026, December 28, 2016, Final Order, p. 17.

25. Q. WHAT OTHER REGULATORY ORDERS AFFECT THE REMEDIATION AT REID GARDNER?

A. In 2008, Nevada Power entered into the AOC with NDEP to address soil and groundwater impacts associated with the historic operation of Reid Gardner. The AOC supersedes previous NDEP orders, allowing Nevada Power and NDEP to prioritize, evaluate and develop corrective actions that meet cleanup standards or contain/control site impacts. Investigation and corrective action activities (i.e., remediation) are completed under the oversight and subject to the approval of NDEP. Pond closure activities were also overseen by the NDEP through the AOC process. A copy of the AOC is provided as **Exhibit Johns-Direct-3**.

26. Q. WHAT OTHER AGREEMENTS AFFECT THE COSTS FOR REMEDIATION OF REID GARDNER?

A. In 2013, Nevada Power and CDWR entered into an EA, establishing cost allocations for potential source areas identified under the AOC. The EA was a component of the settlement and subsequent Termination Agreement with CDWR presented to the Commission in Docket No. 14-05004. A copy of the EA is provided as **Exhibit Johns-Direct-4**.

27. Q. HOW ARE THE CLOSURE COSTS ASSOCIATED WITH REID GARDNER MANAGED?

A. Project activities and closure costs are managed according to the four work activity groups depicted in **Exhibit Johns-Direct-5**. Closure costs associated with decommissioning and demolition activities, including utility relocations, asbestos abatement, structural demolition, and interim site grading are accounted for in Group 1. Closure costs associated with waste management facility closures,

including wastewater evaporation ponds and the onsite landfill, are included in Group 2. Costs associated with environmental characterization and remediation activities are accounted for in Group 3 and are conducted in accordance with the AOC. Both Group 2 and Group 3 activities occur under NDEP oversight. Final site restoration activities are accounted for in Group 4 and will be completed after demolition and remediation work is complete. Each of these work groups are similar to that experienced during the Mohave closure and are currently being experienced during the Navajo closure.

In addition to the work activity groups described above, there are additional costs for ongoing site compliance and maintenance necessary to comply with active permits, such as discharge permits, industrial artificial pond permits, dam safety permits, landfill permits, Environmental Protection Agency's ("EPA") Coal Combustion Residual Rule ("CCR Rule") requirements, site surface area disturbance permits and storm water permits. In addition, the Company is responsible for Bureau of Land Management ("BLM") right of way expenses, and similar ongoing site costs.

28. Q. HAVE PROJECTED COSTS FOR REID GARDNER DECOMMISSIONING, DEMOLITION, AND REMEDIATION BEEN PRESENTED TO THE COMMISSION?

A. Yes. Nevada Power provided preliminary estimates of costs in the ERCR Plan in Docket No. 14-05003. A previous cost estimate for decommissioning and demolition were based on a decommissioning cost study filed in Nevada Power's depreciation case, Docket No. 11-06007. These costs were developed to provide a cost estimate prior to any engineering work being completed.

Remediation cost estimates under the AOC were provided in Docket No. 14-05003. Those figures were based on a cost estimate study prepared in 2014 and reflected potential source areas identified at that time under the AOC, and cost allocations under the EA between Nevada Power and CDWR. The AOC cost estimate study relied on site information available in 2014 to estimate potential investigation activities and assumed corrective action(s) for each potential source area. As work proceeds under the AOC and the nature and extent of environmental conditions are defined, potential corrective actions are evaluated to meet cleanup requirements under the AOC that are protective of human health and the environment and allow for future use of the site. All work under the AOC is subject to NDEP oversight, review, and approval.[9]

29. Q. WHAT REID GARDNER CLOSURE COSTS HAVE BEEN APPROVED BY THE COMMISSION TO DATE?

A. In Nevada Power's 2017 GRC, the Commission approved the recovery of the Reid Gardner 1-4 net book value, stranded inventory, and $5.2 million in remediation costs experienced by Nevada Power at the time of retirement of Units 1-3 in 2014. The Company netted against these costs with non-labor operation and maintenance savings experienced from the retirement period within the rate cycle, the proceeds from an historic insurance settlement credit, and the proceeds from a sale of water rights to the Moapa Band of Paiutes. The final Commission-approved amount for these items approved for recovery in the 2017 GRC was $169 million.[10]

[9] *See* NRS § 704.7318 which provides that NDEP has exclusive jurisdiction over the remediation and reuse of the any site used for the production of electricity from a coal-fired generating plant.
[10] Docket No. 17-06003, Dec. 29, 2017, Modified Final Order, p. 54 – 70.

Nevada Power recovered all post-retirement site closure costs incurred from 2015 through May 2020 as part of the stipulated settlement approved by the Commission for the 2020 Nevada Power GRC, Docket No. 20-06003.[11] The costs recovered included $49.51 million in decommissioning and demolition costs, $39.07 million in pond solids removal and remediation costs, and $23.83 million in carrying charges, totaling $112.41 million.

30. Q. PLEASE DESCRIBE WHAT REID GARDNER COSTS HAVE BEEN INCURRED SINCE NEVADA POWER'S 2020 GRC.

A. As shown in H-CERT-30, Reid Gardner decommissioning and remediation costs incurred through the Test Period total $22.65 million, and the forecasted cost for these activities through the Certification Period is $2.27 million, excluding carrying charges.

The total amount of carrying charges incurred through the Test Period are $8.34 million. Forecasted carrying charges through the Certification Period are $0.97 million.

These costs are further discussed in the Sections V, VI, and VII. **Exhibits Johns-Direct-6** and **Johns-Direct 7** provide additional decommissioning and remediation cost details under the categories presented in **Exhibit Johns-Direct-5** for the Test Period and forecasted cost during the Certification Period.

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[11] Docket No. 20-06003, Jan. 28, 2021, Modified Final Order, Attachment 1, p. 6.

SECTION V. H-CERT-30 REID GARDNER DECOMMISSIONING AND DEMOLITION COSTS (EXHIBIT JOHNS-DIRECT-5, GROUP 1)

31. Q. PLEASE DESCRIBE THE BELOW-GROUND DEMOLITION AND ASBESTOS-ABATEMENT ACTIVITIES COMPLETED BETWEEN JUNE 2020 AND DECEMBER 2022.

A. In May 2020, site decommissioning and relocation activities, above-ground asbestos abatement, and above-ground demolition of the station was complete with below-ground demolition (e.g. foundation, pipe, and duct bank removals) and below-ground asbestos abatement in progress. All costs through May 2020 were recovered in the Nevada Power 2020 GRC, as discussed in Q&A 29.

The below-ground demolition and asbestos abatement activities were subsequently completed by July 2020. As summarized in **Exhibit Johns-Direct-6**, lines 2 and 3 (for the period June to December 2020), the cost of completing the below-ground asbestos abatement was $1.59 million and the cost of completing the below-ground demolition was $1.53 million.

32. Q. PLEASE DESCRIBE ANY OTHER DECOMMISSIONING ACTIVITIES COMPLETED DURING THE TEST PERIOD AND FORECASTED THROUGH THE CERTIFICATION PERIOD.

A. Based on initial analytical testing of the railroad ballast in 2019 during demolition, it was determined that additional waste characterization of the railroad ballast material was needed to determine suitability for disposal in the onsite landfill. Initial analytical results, as quantified by the EPA Method 8015, suggested petroleum-derived hydrocarbon impacts in the railroad ballast. This method is the NDEP-approved and standard analytical method used in petroleum analysis.

Method 8015M is not specific to petroleum-derived hydrocarbons, and will extract hydrocarbons present in other materials, such as coal particulates. Given the onsite landfill cannot accept petroleum-derived hydrocarbons, the Company prepared a sampling and analysis plan, approved by NDEP in June 2020, to complete additional forensic testing to determine if petroleum-derived contaminants were present in the railroad ballast. The results were documented in a waste profile data evaluation report, approved by NDEP in August 2021, and determined that no petroleum-derived impacts above disposal limits were observed in the railroad ballast, and it was suitable for onsite disposal. Railroad ballast excavation activities were completed in 2022, with 20,600 tons of material excavated and disposed in the onsite landfill.

In its August 2021 approval, NDEP directed Nevada Power to complete post-removal sampling of subsurface soil underlying the railroad ballast. Nevada Power submitted a sampling and analysis plan in November 2022 after completing the ballast removal with proposed sample locations and testing, and after receiving NDEP comments, submitted responses to those comments in March 2023. Upon NDEP approval of the plan, Nevada Power will complete the post-removal sampling for this area.

As summarized in **Exhibit Johns-Direct-6,** line 3, under decommissioning costs for the Test Period years 2022 and 2023, the railroad ballast waste characterization and removal cost are $0.36 million. The forecasted cost through the Certification Period related to post-removal sampling is $0.05 million.

33. Q. HOW DO THE RELOCATION, DECOMMISSIONING, AND DEMOLITION COSTS COMPARE TO ORIGINAL ESTIMATES?

A. In Nevada Power's 2020 GRC, $41.49 million in relocation, asbestos abatement and decommissioning costs were recovered. In this GRC, the Company is requesting approval of $3.53 million for decommissioning work unrelated to remediation and $0.15 million in pond closure-related costs (See Q&A 36) incurred during the Test Period and forecasted during the Certification Period. Future decommissioning costs include closure of Mesa Ponds M5 and M7, landfill closure, limited facility removals (e.g. meteorological station) and site restoration related activities. These future costs are currently budgeted at $17 million. The total of the incurred and forecasted costs to completed relocation, decommissioning and demolition amount to $62 million, excluding carrying charges.

In the 2014 ERCR Plan, the Company presented a preliminary estimate of $45.4 million for relocation, decommissioning and demolition costs. The overage present in the current forecast of $62 million primarily reflects differences in assumptions in a preliminary estimate compared to actual work required during relocations, decommissioning and demolition phase activities. One example of this difference is asbestos-abatement, where a budgetary estimate of $3.3 million was assumed in the 2014 ERCR Plan, compared to the $9.68 million for above-ground asbestos abatement actually incurred as of May 2020 and recovered in the 2020 GRC, and $1.59 million in underground asbestos-abatement incurred after May 2020 as part of this GRC, totaling $11.27 million.

At this time, the Company continues to anticipate that the water supply wellfields and water supply pipelines, and onsite water storage ponds will remain in place for

the near future, subject to future site use needs and outcomes of water rights proceedings as discussed in Q&A 67. If and when these features are no longer needed, their removal would be recovered under the regulatory asset. Removal of these site features was not contemplated in the preliminary cost estimates included in the 2014 ERCR Plan.

34. Q. WHAT ARE THE ONGOING COSTS ASSOCIATED WITH REID GARDNER?

A. After the retirement of Unit 4 in 2017, a separate project identifier was established to collect "ongoing costs" incurred to maintain the site and comply with existing permits. These types of costs were not contemplated in the preliminary cost estimates included in the 2014 ERCR Plan but are necessary for site closure and are solely Reid Gardner related. The costs include labor, expenses, and contractor support for the following types of activities:

1. Site-wide dust control and maintenance.
2. Site security, which was reduced to off shift hours as work has progressed and subsequently eliminated after demolition was complete.
3. Compliance with CCR Rule requirements for the applicable ponds and onsite landfill.
4. Compliance with state permits for the remaining ponds, landfill, and raw water ponds.
5. Weekly and periodic inspections for federal and state permits, such as the storm water permit, surface area disturbance permit, landfill permit, pond permit and other similar permits.
6. Wellfield monitoring.

7. Annual BLM right-of-way payments for the Mesa Area and small payments for active grants for items such as the well installations on BLM property. The Mesa Area payment, for which the landfill expansion and Mesa Ponds M5 and M7 are located, alone amounts to more than $400k annually. A final determination to pursue purchase of all or portions of land under this grant will be made once final site use and remediation is complete.

As summarized in **Exhibit Johns-Direct-6**, line 4, the total for ongoing site costs through the Test Period are $4.46 million, excluding carrying charges. The forecasted cost through the Certification Period is $0.72 million. It is expected that these costs will diminish over time as site closure work is completed and future site uses are determined.

SECTION VI: STATUS OF WASTE MANAGEMENT FACILITY CLOSURES (GROUP 2).

35. Q. PLEASE DESCRIBE WHAT WASTE MANAGEMENT FACILITY CLOSURES ARE REQUIRED FOR REID GARDNER.

A. State permits require closure of all former wastewater evaporation ponds and the onsite landfill. In 2015, the CCR Rule was implemented, and the closure of the remaining waste management facilities has been subject to the CCR Rule closure standards since that time.

Pond closures are typically completed in two distinct steps: (1) removal of the pond solids and liner systems, and (2) final restoration of the pond areas during site remediation and site restoration. For Mesa Ponds M5 and M7, current CCR Rules

require a demonstration that groundwater monitoring concentrations do not exceed the groundwater protection standards as set forth in the CCR Rule. The landfill closure will be completed by installing a soil cover system (or equivalent) that meets all permit and CCR Rule requirements. Post-closure care of the landfill will occur over a period of 30 years and will, at a minimum, include maintaining the final cover system integrity, operation of any contact water collection and removal systems and continued groundwater monitoring and reporting. Industry anticipates that EPA will be issuing revisions to the CCR Rule in 2023 which may affect closure requirements.

36. Q. WHAT WASTE MANAGEMENT FACILITIES HAVE BEEN REMOVED FROM SERVICE AND CLOSURE INITIATED DURING THE TEST PERIOD?

A. In April 2021, Mesa Ponds M5 and M7, originally constructed in 2010, were removed from service in response to the supplemental CCR Rule requirement in September 2020 ponds not meeting specific design requirements. The state-approved design standard, which requires double-geosynthetic liners with interstitial leak detection and collection systems, did not conform to the CCR Rule standard published in 2015, after the ponds were built. These ponds were the last ponds to support Unit 4 operations and provided storage of incidental site water during demolition. Since April 2021, wastewater has been evaporating which was expected to take two to three years to complete prior to removal of the solid materials (primarily a sodium sulfate salt) that remain.

In 2022, the Company initiated pond solids removal planning under both the CCR Rule and state requirements. Similar to the other ponds previously closed and solids

removed, the earthen embankments and structures at Mesa Ponds M5 and M7 will remain in place until it is determined that they would not be required for site remediation or future site use. The pond solids removal action from Mesa Ponds M5 and M7 will be completed by the end of 2024.

As summarized in **Exhibit Johns-Direct-6**, line 5, the total for Mesa Ponds M5 and M7 solids removal through the Test Period is $0.1 million, excluding carrying charges. The forecasted cost during the Certification Period is $0.05 million.

37. Q. WHAT OTHER WASTE MANAGEMENT FACILITIES WILL BE CLOSED IN THE FUTURE?

A. The onsite landfill closure will be completed as a final activity once site remediation is complete and no longer needed. The landfill was most recently used in 2022 to support the ash fill removals underneath the former coal pile areas as part of the AOC Site Remediation work discussed in Q&A 51.

SECTION VII. AOC SITE REMEDIATION COSTS (GROUP 3)

38. Q. PLEASE DESCRIBE THE AOC GOVERNING REMEDIATION OF THE REID GARDNER SITE.

A. Nevada Power and NDEP entered into an AOC on February 22, 2008, to address potential soil and groundwater impacts associated with operation of Reid Gardner. The AOC defines the general framework to proceed with identification, characterization, corrective action planning, corrective action implementation, long-term operations, and maintenance to address soil and groundwater environmental concerns at Reid Gardner. The AOC does not identify specific sites at Reid Gardner that must be addressed, recommend corrective actions, or provide

the schedule to complete the work. Instead, the AOC establishes a process to allow the parties to work together collaboratively to identify and prioritize work activities in a logical manner. The AOC also requires Nevada Power to reimburse the NDEP for its direct oversight costs and directly reimburse NDEP-selected contractors working under its supervision.

Nevada Power prepared the Preliminary Source Area Identification and Characterization ("PSAIC") Report to identify potential sources of environmental impacts and summarize current available data. The report was approved by NDEP in July 2013. The PSAIC Report identified 35 potential source areas that require further site characterization and potential corrective action. The potential source areas are geographically grouped together into general categories listed below:

- Site-wide common activities (not geographically specific);
- Potential pond source areas;
- Potential station source areas;
- Potential petroleum source areas;
- Potential Mesa source areas; and,
- Potential north station source areas.

Exhibit Johns-Direct-8 - AOC Site Map provides an overview of these geographic areas at Reid Gardner.

39. Q. HOW DOES THE COMPANY MANAGE THE AOC COSTS?

A. In 2014, the Company established a project-specific work breakdown structure for the AOC to align project activities with potential source areas, and associated cost allocations under the EA with CDWR. Project activities are tracked as individual

projects, and costs are transferred monthly into the regulatory asset account for Nevada Power, or to a separate liability account for CDWR. Per the conditions of the EA, CDWR pre-funds the liability account on a semi-annual basis. Each year, Nevada Power and CDWR true-up costs in the liability account. To date, there have been no cost disputes between Nevada Power and CDWR for project work or associated costs.

40. Q. PLEASE SUMMARIZE THE COSTS FOR AOC SITE REMEDIATION ACTIVITIES COMPLETED BETWEEN JUNE 2020 AND DECEMBER 2022 AS WELL AS THOSE THAT WILL BE COMPLETED THROUGH THE END OF CERTIFICATION PERIOD.

A. As summarized in H-CERT-30, Nevada Power's share of Site Remediation Costs incurred in the Test Period include $14.61 million and the forecasted costs for these activities during the Certification Period are $1.47 million, excluding carrying charges.

The total amount of carrying charges incurred through the Test Period are $3.88 million. The forecasted carrying charges during the Certification Period ending are $0.58 million.

These costs are further discussed in detail for each geographic area and source area in the remainder of this section. **Exhibit Johns-Direct-7** further categorizes Nevada Power's share of these costs incurred in the Test Period and forecasted costs through the Certification Period, excluding carrying charges.

41. Q. PLEASE DESCRIBE AOC SITE-WIDE COMMON ACTIVITIES.

A. Site-wide common activities under the AOC include general management and coordination, agency oversight, site-wide groundwater monitoring, site-wide studies, data management, and program documents that are not allocable to a specific source area. These activities are necessary to comply with the AOC and align with the EA allocations agreed upon with CDWR.

42. Q. WHAT SITE-WIDE COMMON COSTS ARE RE-OCCURRING COSTS TO MANAGE AND MAINTAIN COMPLIANCE WITH THE AOC?

A. Site-wide common costs include activities that are re-occurring (or ongoing). Common re-occurring site-wide costs include project management, data management, document management, and required compliance monitoring of the site. Outcomes of site investigation or remediation activities have no impact on the necessity to complete these activities. Specific re-occurring site-wide common activities include:

1. Management and oversight costs by Nevada Power, Consultants (program and technical), NDEP, and NDEP's third-party oversight contractor.
2. Costs for EA meetings with CDWR.
3. Updates to existing general site work documents required by the AOC, such as the site health and safety plans, quality assurance project plans, and fact sheets.
4. Site-wide groundwater and surface water monitoring in accordance with an NDEP-approved monitoring plan. Quarterly and semi-annual monitoring events are completed and reported on an annual basis. Well maintenance activities, such as well redevelopment and root removal in

shallow wells, are also addressed as needed under the monitoring program. In December 2022, NDEP approved a well installation work plan to install seven additional shallow monitor wells in the station area to address data gaps related to shallow groundwater gradients and water quality around the station area. The wells were installed by February 2023 and will be included in the semi-annual groundwater monitoring program.

Exhibit Johns-Direct-7, lines 2 through 11, represent the re-occurring site-wide common costs. Nevada Power's share of these costs incurred during the Test Period are $3.30 million, excluding carrying charges. Nevada Power's share of the forecasted cost during the Certification Period is $0.58 million

43. Q. WHAT SITE-WIDE COMMON COSTS ARE STUDIES THAT WERE COMPLETED THAT WILL SUPPORT THE SITE-WIDE CONCEPTUAL SITE MODEL REPORT AND FUTURE REMEDY DECISIONS?

A. The following site-wide common activities are in progress or completed to support future remedy decisions:

- An Addendum to the Background Conditions Report was approved by NDEP in April 2022 to establish alluvial groundwater background ranges using additional data collected from wells installed during characterization since the original report was approved in 2014. It is important to note that the evaluation determined that background levels are highly variable due to the geology of the alluvial fill. The range of background levels will be used as a line of evidence in the site-wide conceptual site model ("CSM") report recognizing that exceedances of

the range do not necessarily suggest impacts from Reid Gardner operations. The purpose of the CSM report is discussed in Q&A 46 below.

- The Muddy River investigation to assess potential impacts to surface water quality was substantially complete as of May 2020 and costs incurred through May 2020 were recovered in Nevada Power's 2020 GRC. Costs to complete the reporting are included in this GRC. NDEP approved the report in July 2020 and data is being used in the CSM report. In addition, a replacement well along the muddy river was installed in 2021 in accordance with a work plan approved by NDEP in February 2021.

Exhibit Johns-Direct-7, lines 13 and 14, represent these site-wide common studies. Nevada Power's share for these site-wide common costs incurred during the Test Period are $117,438, excluding carrying charges. No forecasted costs are expected during the Certification Period for these activities. Each of these activities is managed as an individual project and costs are tracked separately.

44. Q. WHAT SITE-WIDE COMMON CORRECTIVE ACTION PLANNING ACTIVITIES ARE IN PROGRESS THAT WILL SUPPORT FUTURE REMEDY DECISIONS?

A. Site-wide common corrective action planning activities, including evaluation of soil salinity survey data and initial pond area cover system options infiltration modeling are in progress to support future remedy decisions. The information

developed will assist in developing corrective action options base on the CSM report findings.

Exhibit Johns-Direct-7, line 15, represent these site-wide common studies. Nevada Power's share for these site-wide common costs incurred during the Test Period are $92,411, excluding carrying charges. Nevada Power's share of the forecasted cost during the Certification Period is $20,691.

45. Q. BASED ON AOC WORK COMPLETED TO DATE, WHAT IS THE STATUS OF THE SITE-WIDE CSM REPORT?

A. Preparation of the site-wide CSM and geochemical modeling of the site conditions is based on the source-specific investigations and corrective actions completed to date. The CSM is required by the AOC to synthesize the work completed through background assessments, source specific or site-wide investigations, data evaluations and related documents and it presents a comprehensive understanding of the soil and groundwater conditions across the site.

Initial development of the CSM report began prior to June 2020 in parallel with completing source specific soil and groundwater investigations and characterization reports. Additionally, further evaluation of alluvial background conditions, as discussed above, was also in progress. It was determined that many of these activities needed to be completed and documented to better evaluate the site-wide impacts and source-specific contributions to underlying groundwater. In December 2022, draft sections 1 through 4 of the CSM report and Appendices A through E, were submitted to NDEP to initiate its review. The balance of the CSM report's sections and appendices will be submitted to NDEP by the end of 2023.

The CSM report will support further corrective action planning and implementation. The CSM will also identify site characterization related data gaps to be addressed either through further characterization or as part of corrective action planning.

Exhibit Johns-Direct-7, line 12, represents Nevada Power's share of the site-wide CSM development. Nevada Powers' share of costs incurred during the Test Period, is $2.67 million, excluding carrying charges. Nevada Power's share of the forecasted cost during the Certification Period is $0.53 million.

46. Q. PLEASE DESCRIBE POND SOURCE AREA ACTIVITIES.

A. Seven potential pond source areas were identified in the PSAIC Report within the Pond Source Areas, as summarized in **Table-Johns Direct-1** below. Source area PA-4 is associated with the onsite landfill hall road and status is discussed with the Mesa Source Area activities in Q&A 59.

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Table Johns-Direct-1

Source No.		Potential Source Area	AOC Status
PA-1		Hogan Wash	Investigation reporting completed November 2021.
PA-2		Ponds 4B and 4C	Pond solids removal completed December 2015. Investigation reporting completed June 2021.
PA-3		Former Pond 4A	Pond solids removal completed December 2015. Investigation reporting completed May 2020.
PAs-5, 6, 7		Ponds D, E, F, and G	Pond solids removal completed between 2010 and 2017. Investigation reporting completed March 2022.
PA-8		Hydrogen Peroxide Tank Release	Investigation Closed in 2018.

Pond source area activities to date have included pond solids and liner removal (as discussed in Section VI), surface and subsurface soil characterization, hydrogeological and groundwater characterization, and reporting.

47. Q. WHAT POND SOURCE AREA CHARACTIZATION-RELATED ACTIVITIES ARE COMPLETE WITH FURTHER ACTIONS BEING PLANNED?

A. Site characterization activities (i.e., field investigation and data collection) for pond source areas PA-1, PA-2, PA-3, and PA-5, 6, and 7 have been completed to support site-wide CSM development. All work was implemented in accordance with NDEP-approved work plans and field investigation activities were completed between 2015 and 2019, including installation of 134 hydraulic profile tool/direct

push borings, approximately 100 monitoring wells, surface and subsurface soil sampling, and geochemical sampling in each Pond Source Area. All costs through from 2015 through May 2020 were fully recovered as part of the 2020 Nevada Power GRC.

Costs incurred in the Test Period, are associated with preparation of the source-specific soil and groundwater characterization reports that compile and summarize the investigation data collected under NDEP-approved work plans. NDEP provided concurrence for each report that the investigation work was completed in accordance with work plans for the PA-1 area in September 2021, the PA-2 area in June 2021, the PA-3 area in May 2020, and the PA 5, 6, and 7 areas in March 2022. Based on investigation results and CSM development, working planning to address potential data gaps with the groundwater monitoring network area is in progress focusing on permanent monitoring wells at key locations where a data gap exists or long-term monitoring is appropriate.

Exhibit Johns-Direct-7, lines 19 through 22, represent these pond source area costs. Nevada Power's share of costs for this work incurred in the Test Period, are $180,066, excluding carrying charges. Nevada Power's share of the forecasted cost during the Certification Period is $0.10 million.

48. Q. SUMMARIZE WHAT POND SOURCE AREA WORK REMAINS.

A. The results of the pond source area characterization work are being used to develop the CSM report being prepared as a site-wide common activity. Based on the findings of the CSM report, focused data gaps may be identified that will either complete site characterization activities or support corrective action planning.

However, the work completed to date and described in Q&A 47 was necessary to support any corrective action for the site and, in itself, is considered to be substantially complete.

49. Q. PLEASE DESCRIBE STATION AREA ACTIVITIES.

A. Nine potential source areas were identified in the station area, as summarized in **Table Johns-Direct-2**. These areas were included in the AOC as potential source areas based on their use to manage and handle coal, plant-derived process water, plant-derived wastewater, historic records, or in the case of SA-17, historic reporting of waste disposal. Station area activities to date have included surface and subsurface soil investigations, hydrogeological and groundwater characterization, and reporting.

Table Johns-Direct-2

Source No.	Potential Source Area	AOC Status
SA-1	Unit 4 Treated Water Pond	Investigation closed, determination in 2019.
SA-2	Unit 4 Cooling Tower	Investigation closed, determination in 2019.
SA-3	Unit 4 Cooling Tower Catch Basin	Investigation complete, Reporting in progress.
SA-4	Units 1, 2, and 3 coal piles, Unit 4 coal pile, and fly ash under the Unit 4 coal pile	Investigation and corrective action complete, corrective action reporting in progress.
SA-5/6 (one area)	Area of previous fly ash fill	Future investigation planned.
SA-7	Unit 4 settling pond (Foster Wheeler Pond)	Investigation complete, reporting in progress.
SA-8	Units 1, 2, and 3 catch basin	Investigation closed, determination in 2016.
SA-17	Reported previous waste disposal area	Investigation closed, determination in 2016.
SA-19	Units 1-3 scrubbers and Unit 4 absorber area	Investigation complete, reporting in progress.

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50. Q. SUMMARIZE WHAT CHARACTERIZATION WORK IN THE STATION AREA WAS COMPLETED BETWEEN JUNE 2020 AND DECEMBER 2022, WITH FURTHER ACTIONS BEING PLANNED.

A. Source area soil characterization work plans for the SA-7 Unit 4 settling ponds, SA-7 Unit 4 settling ponds, SA-19 Units 1,2, and 3 scrubber area, and SA-19 Unit 4 absorber area were approved by NDEP in 2020. Field investigations of these areas were completed in accordance with the characterization work plans during the end of demolition work. Costs incurred as of May 2020 were recovered as part of the Nevada Power 2020 GRC.

Data evaluation and draft soil characterization reports, including a source-specific groundwater evaluation for these source areas were submitted to NDEP in October 2021 once alluvial background concentrations for groundwater were approved by NDEP as discussed in Q&A 43. NDEP comments have been received and are being addressed on each report after installation of station area monitoring wells in 2022 as discussed in Q&A 42. These additional monitoring wells assist in better defining groundwater gradients and shallow groundwater quality in the station area, including these source areas. The soil characterization reports for these areas will be updated with additional groundwater information in response to NDEP comments and re-submitted for NDEP review in 2023.

The SA-3 Unit 4 cooling tower catch basin characterization work plan was prepared and approved by NDEP in June 2022. Field sampling work was completed in 2022 during the SA-4 Units 1, 2, and 3 coal pile area corrective action activities. A draft soil characterization report for this source area will be provided to NDEP in 2023.

Limited early planning to characterize the SA 5/6 fly ash fill areas on adjacent property was completed to determine areas that may require BLM access. Field investigation of these areas will be incorporated with other needs for soil or groundwater investigation on BLM land in the future as part of the site-wide CSM process.

Exhibit Johns-Direct-7, lines 38, 42, 43, 46 and 47 represent these station source area costs. Nevada Power's share of costs for this work incurred during the Test Period are $206,843, excluding carrying charges. Nevada Power's share of the forecasted cost during the Certification Period is $50,305.

51. Q. SUMMARIZE THE CORRECTIVE ACTION WORK IN THE STATION COAL PILE AREAS COMPLETED DURING THIS GRC PERIOD, WITH FURTHER ACTIONS BEING PLANNED.

A. Source area characterization of the SA-4 coal pile area (and underlying Waste Management Unit "WMU"-12 source area) and SA-4 Units 1-3 coal pile area is complete, and costs were recovered as part of the 2020 GRC. These areas were included in the AOC to address the potential that either the coal itself, or original coal ash and soil fill, used to the create the base of the coal pile areas, resulted in detrimental impacts to soil or groundwater. The use of ash as fill material has historically been an accepted beneficial use of the material.

Based on the investigation findings, additional ash/soil waste profiling was necessary to determine suitability of the fill material to be disposed in the onsite landfill based on total petroleum hydrocarbon levels detected in samples during investigations, as quantified by EPA Method 8015. Soils with total petroleum

hydrocarbons above 100 mg/kg cannot be disposed of in the onsite landfill and must go to an off-site permitted facility. Method 8015 is the NDEP approved and standard analytical method used in petroleum analysis. This method, though, is not specific to the detection of petroleum-derived hydrocarbons, and will extract hydrocarbons present in other materials, such as coal particulates which is present in the ash/soil fill in the coal pile areas. NDEP approved a waste profile sampling and analysis plans in July 2020 to collect additional samples and use forensic testing methods to differentiate non-petroleum impacted fill material from suspected or petroleum impacted fill material. The results of the waste profiling were documented in a waste profile data evaluation report that was approved by NDEP in May 2021, which determined that most of the ash fill was suitable for onsite disposal and identified two locations within the fill where results that suggest offsite disposal was appropriate. Corrective Action work plans for the excavation of the coal pile areas were subsequently approved by NDEP in August 2021.

Removal Actions commenced in December 2021 and were completed in December 2022 when the excavation contractor demobilized. A total of 462,130 cubic yards of ash/soil fill was removed from the Units 1-3 coal pile area and Unit 4 coal pile/ WMU-12 area and disposed of in the onsite landfill. Based on the waste profile results and field oversight during excavation, offsite disposal was limited to approximately 6,800 cubic yards of material where potential petroleum hydrocarbons were present based on the forensic testing methods. Two areas of ash/soil fill that extended into the existing road areas adjacent to the Unit 4 coal pile were identified but not removed at this time. These areas will be further evaluated and considered for future removal action once easements, water lines, and the future need for the road is determined. Post-excavation subsoil confirmation

sampling, analytical testing, and corrective action reports to document the work completed are in progress and will be submitted to NDEP in 2023.

Exhibit Johns-Direct-7, lines 39 through 41, represent these station source area costs. Nevada Power's share of costs for this work incurred in the Test Period are $6.68 million, excluding carrying charges. Nevada Power's share of the forecasted cost during the Certification Period is $0.15 million.

52. Q. SUMMARIZE WHAT STATION AREA WORK REMAINS.

A. Characterization work planning for the SA 5/6 area will be completed once any additional offsite access needs for soil sampling and groundwater monitoring is identified such that a comprehensive application can be submitted to the BLM.

Impacts to groundwater underlying the station area being evaluated as part of the site-wide CSM using data collected as part of the monitoring program and source area investigation activities. If source specific well installation, monitoring, or remediation beyond the correction actions taken to date are needed to address groundwater impacts, costs will be recovered as part of the source area to appropriately allocate costs between Nevada Power and CDWR.

53. Q. PLEASE DESCRIBE PETROLEUM SOURCE AREA ACTIVITIES.

A. Eight potential petroleum source areas were identified within the station area, as summarized in **Table Johns-Direct-3** below. Each of these areas represents locations where historic petroleum handling occurred, many dating back to the original station construction.

Table Johns-Direct-3

Source No.	Potential Source Area	AOC Status
SA-9	Units 1 and 2 Emergency Diesel Generator	Investigation and limited excavation complete. No further action request under NDEP review.
SA-10	Former Units 1, 2, and 3 lube oil rack	Remediation complete. No Further Action Determination issued in 2017.
SA-11	Former Gasoline Underground Storage tank (1000-gallon) and Warehouse 1	Remediation complete. No Further Action Determination issued in 2017.
SA-12	Former Diesel aboveground storage tank (850,000 gallon)	No Further Action Determination issued in 2017.
SA-13	Former Diesel Fuel Unloading Area	Remediation complete. No further action request under NDEP review.
SA-14	Former Underground Product Piping, Petroleum Tanks	Supplemental Investigation in progress to evaluate residual conditions.
SA-15	Free-Product Recovery System	Remediation complete. No Further Action Determination issued in 2017.
SA-16	Vehicle Maintenance Area	Remediation complete. No Further Action Determination issued in 2017.

Petroleum source area activities to date have included surface and subsurface soil characterization, groundwater investigations, excavation and offsite disposal of contaminated material, and reporting.

54. Q. SUMMARIZE WHAT PETROLEUM AREA CHARACTERIZATION WORK AND CORRECTIVE ACTION WORK IN THE STATION AREA COMPLETED DURING THIS GENERAL RATE CASE PERIOD.

A. Based on the prior findings and reporting approved by NDEP, an excavation plan to remove impacted soils in the SA-13 was prepared in 2021, such that the

excavation could be completed during the larger SA-4 coal pile area removal actions in 2022. A total of 3,801 cubic yards of petroleum-impacted soils was excavated and disposed at a permitted offsite landfill. The SA-13 completion report and closure request was submitted to NDEP in April 2023.

The SA-9 soil characterization report, documenting field investigation results, was approved by NDEP in December 2021. The report recommended a limited supplemental characterization of the area to further define the extent and depth of impacts at the source area. The supplemental characterization work plan was approved by NDEP in April 2022 and field work was completed in May and June 2022. The supplemental report and closure request was submitted to NDEP in December 2022. Nevada Power prepared responses to NDEP comments and re-issued the supplemental report and closure request to NDEP in April 2023.

Exhibit Johns-Direct-7, lines 52 and 56, represent the SA-9 and SA-13 petroleum source area costs. Nevada Power's share of costs for this work incurred in the Test Period are $612,530 excluding carrying charges. Nevada Power's share of the forecasted cost during the Certification Period is $33,583. Presuming closure requests are approved by NDEP with no further action, limited costs may be incurred in the future to finalize reports after the certification period.

55. Q. SUMMARIZE THE STATUS OF THE SA-14 FORMER UNDERGROUND PIPING RESIDUAL FREE PRODUCT EVALUATION.

A. In 2015, the diesel-free product recovery system was removed from service due to limited recovery of diesel. The recovery system was originally installed in the 1980s (and subsequently upgraded) to recover diesel that was released from

underground pipes that provided fuel for unit ignitor operation and general equipment fueling. Prior to plant retirement, operation of these recovery systems was included as part of normal operation and maintenance expense. At no time did the Commission rule that such expenses were not allowable. Regardless, the underground piping in question was original to the plant construction and as a result did not include modern release detection systems. This underground piping system was removed from service after the release was discovered in 1985.

Nevada Power completed investigation of residual subsurface conditions utilizing laser-induced fluorescence drilling techniques to map the residual free product remaining in the subsurface. Additional evaluations for residual free-product mobility and natural attenuation have also been completed to evaluate residual mobility and potential for ongoing biodegradation. A draft SA-14 area CSM report was originally submitted to NDEP in 2017 with multiple revisions by the Company to include additional groundwater monitoring results from data collected in 2018 and 2019. The latest version of the SA-14 area CSM report is dated April 30, 2021.

Based on the results presented in the latest version of the SA-14 area CSM report, Nevada Power prepared a supplemental work plan, approved by NDEP in December 2021, to install seven new shallow wells, conduct and document weekly removal residual free product for a three-month period, followed by monthly gauging of the wells for a six-month period following completion of the weekly removal actions. Well installation and free-product recovery efforts were completed in December 2022 and post-test monitoring will be completed in June 2023. The results of the supplemental work plan will be incorporated into the SA-14 area's CSM report to determine if it remains a candidate for closure without

further remediation. Final determinations for closure will be made by NDEP after Nevada Power submits the updated report in 2023.

Exhibit Johns-Direct-7 line 56, represents the costs for this SA-14 source area. Nevada Power's share of costs for this work incurred in the Test Period are $271,093, excluding carrying charges. Nevada Power's share of forecasted cost during the Certification Period is $6,571.

Presuming a closure request is supported by the supplemental characterization work and is approved by NDEP with no further action, limited costs may be incurred in the future to finalize reports and well abandonment. If further action is deemed necessary, the costs will be assessed based on the specific corrective actions developed and approved by the NDEP in the next GRC.

56. Q. PLEASE DESCRIBE MESA SOURCE AREA ACTIVITIES.

A. Ten potential source areas were identified in the Mesa Area, as summarized in **Table Johns-Direct-4** below. Source areas MA-1 through MA-9 (excluding MA-7), which consist of historic and current landfill operations, will be evaluated as one groundwater area with no soil evaluation required. Source areas MA-7 and PA-4 will be addressed as individual source areas.

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Table Johns-Direct-4

Source No.	Potential Source Area	AOC Status
MA-1	Closed Sanitary Landfill (WMU-1)	Mesa groundwater evaluation in progress as part of the CSM. Groundwater monitoring completed under site-wide program.
MA-2	Special Asbestos Waste Cell (WMU-2)	See MA-1.
MA-3	Disposal Area for Construction and Demolition Debris (WMU-3)	See MA-1.
MA-4	Class III (Industrial Waste Landfill (Active Permit)	See MA-1.
MA-5	Closed Ash Disposal Area (WMU-5)	See MA-1.
MA-6	Evaporation Ponds P1 – P5	See MA-1.
MA-7	Landfill Used for Industrial and Non-Industrial Waste (WMU-7)	Pursuing land purchase to implement remedy.
MA-8	Disposal Area for Water Treatment Waste (WMU-9)	See MA-1.
MA-9	Former Mesa Dredge Pond (WMU-10)	See MA-1.
PA-4	Closed Fly Ash Fill Area under Landfill Haul Road (WMU-6)	Address during final remediation and site restoration.

Mesa source area activities to date have included surface and subsurface soil characterization, groundwater investigations, and reporting. A separate investigation of the PA-4 landfill haul road area will be completed once plant and pond solids removal projects are complete.

57. Q. SUMMARIZE THE STATUS OF THE MESA GROUNDWATER EVALUATION.

A. Nevada Power is evaluating the groundwater sampling data collected as part of the AOC and state landfill permit requirements to develop the CSM for groundwater impacts associated with historic and/or current use of this area. The results of the

evaluation were submitted to the NDEP for review in December 2022 a draft CSM report deliverable. No field investigation work is currently planned for this area other than continued groundwater monitoring. However, monitor well replacements may be required to address well deterioration (e.g. well screen deterioration) and / or changes in water levels to support long-term post-closure monitoring. Well replacement costs may be captured as a source-specific or general site cost.

Exhibit Johns-Direct-7, line 63, represents these Mesa groundwater evaluation costs. Nevada Power's share of costs for this work incurred in the Test Period are $43,687 excluding carrying charges. No costs are anticipated during the Certification Period.

58. Q. SUMMARIZE THE STATUS OF THE WMU 7 AREA.

A. Investigation of the WMU-7 area was completed in 2009. The costs for this investigation work were included and approved in the 2017 Nevada Power GRC. Nevada Power is pursuing the purchase of approximately six acres of land from the BLM, on which the former historical landfill area at WMU-7 is present. In February 2022, Nevada Power responded to a BLM request for an updated justification for the direct sale of this property and is still awaiting a response.

Exhibit Johns-Direct-7, line 64, represents the WMU-7 area costs. Nevada Power's share for this work incurred during the Test Period are $1,658, excluding carrying charges. No costs are anticipated during the Certification Period.

59. Q. WHEN WILL THE PA-4 HAUL ROAD INVESTIGATION BE COMPLETED?

A. The PA-4 haul road was partially constructed with ash material, which has commonly been beneficially used as structural fill material for construction. Investigation of the haul road area has been a lower priority because the haul road continues to be actively used during decommissioning and remediation at the station.

Planning for this area will begin once higher priority reporting activities are complete and the road becomes available for investigation without compromising access to Mesa facilities. No costs have been incurred to date for this source area.

60. Q. PLEASE DESCRIBE NORTH STATION AREA ACTIVITIES.

A. One potential source area was evaluated in the north station area, as summarized in **Table Johns-Direct-5** below. The area was used for ash handling and non-scrubber plant wastewaters from Units 1, 2, and 3 prior to installing scrubbers in the mid-1970s. The area was re-purposed for raw water ponds for Units 1, 2, 3, and 4 during Unit 4 construction.

Table Johns-Direct-5

Source No.	Potential Source Area	AOC Status
SA-18	Ash Settling Pond "ASP"-1, ASP-2, ASP-3, Former clear wells, former fly ash disposal area (WMU-11)	Work planning for onsite investigation complete, initial investigation complete and report is being submitted to the NDEP

61. Q. SUMMARIZE WHAT AOC CHARACTERIZATION WORK FOR THE NORTH STATION AREA IN PROGRESS.

A. A waste and site characterization plan was approved by NDEP in December 2020 to complete investigation and waste characterization for the portion of the source area on the Company's property. Field data collection was completed in 2021 and a draft waste profiling and site characterization report was submitted to NDEP in March 2023. Investigation of the adjacent offsite areas on BLM land and groundwater will be completed once plans are developed and applications to access the area are submitted and processed by BLM.

Exhibit Johns-Direct-7, line 68, represents the north station area costs. Nevada Power's share of costs for this work incurred in the Test Period are $435,639, excluding carrying charges. Nevada Power's share of the forecasted cost during the Certification Period ending is $3,780.

62. Q. SUMMARIZE WHAT CORRECTIVE ACTION WORK NORTH STATION AREA IS IN PROGRESS.

A. The Company commenced corrective action work planning to remove a portion of the ash fill adjacent to the raw water pond on Company property.

Planning for investigating portions of the north station area on adjacent BLM property will be completed in parallel with the SA 5/6 area after coordination with the BLM. Focus on these source areas was identified as lower priority for the AOC.

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63. Q. HOW DO THE AOC REMEDIATION COSTS COMPARE TO THE 2014 ERCR ESTIMATE?

A. In the ERCR Plan, Docket No. 14-05003, Nevada Power estimated the AOC remediation costs for Reid Gardner to be $120.5 million. As discussed in Q&A 28, this estimate was based on site information available in 2014 to estimate potential characterization and corrective action costs prior to developing source area work plans, completing field investigations, and identifying corrective actions that are protective of human health and the environment.

AOC remediation costs recovered in the 2017 GRC were $5.2 million (see Q&A 29). AOC remediation costs recovered in the 2020 GRC were 39.1 million (see Q&A 29). AOC remediation costs presented for recovery in this GRC period are 16.1 million. Currently forecasted future costs are estimated to be $32.0 million after May 2023 that would largely be related to pond area corrective actions and /or source area removal actions. The total amount of recovered costs to date, current costs presented for recovery and forecasted future costs amount to $92.4 million, approximately $29.1 below the 2014 ERCR estimate. These costs exclude carrying charges.

It is important to highlight that the AOC work is completed under NDEP oversight and all activities, from source area characterization work planning to corrective action implementation are reviewed and approved by NDEP. Completion of work activities, such as characterization activities, represent completion of phases of work typical of site remediation.

SECTION VIII. REID GARDNER DECOMMISSIONING, DEMOLITION, AND REMEDIATION EXPECTED FUTURE COSTS

64. Q. ARE THE CURRENT AND REMAINING DECOMMISSIOING, DEMOLITION, AND REMEDIATION COSTS EXPECTED TO BE WITHIN ORIGINAL ESTIMATES PRESENTED TO THE COMMISSION?

A. In the ERCR Plan in Docket No. 14-05003, Nevada Power estimated the decommissioning, demolition, and remediation costs for Reid Gardner to be $165.9 million, based on an estimate of $45.4 million for decommissioning and demolition, and $120.5 million for remediation. No costs were included for ongoing Reid Gardner site costs in the ERCR Plan, which have also been experienced at both Mohave and Navajo.

Based on costs to date and currently forecasted costs to complete remaining site work, expected total project costs are tracking to be approximately $177.7 million, approximately 7 percent above the $165.9 million estimate from the ERCR Plan, excluding carrying costs. If ongoing site costs were excluded, the current forecast would be approximately 7 percent below the ERCR Plan estimate. See **Table-Johns Direct-6** below for a summary comparison.

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Table Johns-Direct-6

General Rate Case	Decommissioning, Demolition and Ongoing Site Costs	Remediation	Total
2017 General Rate Case	---	$5.2 million	$5.2 million
2020 General Rate Case	$49.5 million[1]	$39.1 million	$88.6 million
2023 General Rate Case	$8.8 million[2]	$16.1 million	$24.9 million
Future costs	$27 million[3]	$32 million	$56 million
CURRENT ESTIMATE	**$85.3 million**	**$92.4 million**	**$177.7 million**
2014 ERCR Plan estimate	$45.4 million[4]	$120.5 million	$165.9 million

1. Above amount includes $8.01 million of ongoing site costs
2. Above amount includes $5.18 million of ongoing site costs from the Test Period and Certification Period.
3. Above amount includes $10 million of ongoing site costs
4. The ERCR Plan estimate did not contemplate ongoing site costs

65. Q. ARE OTHER FUTURE COSTS NOT INCLUDED IN THE ABOVE ESTIMATES?

A. Yes. It is expected that there will be long-term costs to monitor and maintain Reid Gardner. While these costs are uncertain at this time, the expectation is that such costs will be incurred similar for the Mohave and Navajo retirement projects.

66. Q. WHAT IS THE STATUS OF THE FUTURE LAND USE FOR REID GARDNER?

A. All future land use(s) or disposition of the land associated with Reid Gardner is undetermined at this time. Near term beneficial re-uses of the property are described below.

In the First Amendment to the 2021 Joint IRP, Docket No. 22-03024, the Commission conditionally approved the Reid Gardner Battery Energy Storage System ("BESS"), a 200-megawatt facility with 2 hours of duration. This project, encompassing approximately seven acres, is located in the footprint of the former Units 1-3 cooling towers north of the existing substation.

In addition, the Company continues to plan for interconnections associated with renewable projects and the Overton Power transmission line at the Reid Gardner Substation.

67. Q. WHAT IS THE STATUS OF THE WATER RIGHTS AND ASSOCIATED WATER WELLS AND CONVEYANCE SYSTEMS AT REID GARDNER?

A. In January 2019, the State Engineer issued Interim Order 1303, designating the administration of all water rights in seven hydrologic basins be managed as a joint administrative unit, which shall be known as the Lower White River Flow System ("LWRFS"). The Reid Gardner water rights are within these basins. The interim order identifies that the amount of groundwater appropriations within the LWRFS greatly exceeds the total water budget within the flow system. The State Engineer held hearings on the matter during October 2019, resulting in Order 1309, issued June 15, 2020, in which the held that the LWRFS be managed as a joint administrative unit and established a maximum quantity of groundwater being pumped to not exceed 8,000 acre feet annually or less without causing further declines in the Warm Springs area spring flow and flow in the Muddy River. In April 2022, the order was vacated in the Eighth Judicial District Court. The State Engineer has appealed the decision to the State Supreme Court.

The outcomes of these proceedings will weigh heavily on the future viability and use of the groundwater rights, wellfield, and conveyance system associated with Reid Gardner. Until such time, Nevada Power will continue to maintain all water rights and facilities.

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

A. Yes, it does.

EXHIBIT JOHNS-DIRECT-1

MATHEW J. JOHNS
VICE PRESIDENT, ENVIRONMENTAL SERVICES AND LAND MANAGEMENT
NV Energy, Inc.
6226 West Sahara Avenue
Las Vegas, NV 89146
(702) 402-5477

Mr. Johns joined NV Energy in August 2015. He has over 25 years of experience in environmental remediation, project, and program management. Prior to joining NV Energy, Mr. Johns worked as an environmental consultant for industrial companies primarily in the power, manufacturing, mining, oil and gas sectors.

EMPLOYMENT HISTORY

NV Energy, Inc.
8/2015 to 2/2022

Director, Environmental Remediation and Resource Development
Primary responsibility for managing Regulatory Assets and Asset Retirement Obligations ("AROs") for Energy Supply. These obligations include decommissioning, demolition, and environmental remediation of the company's generating facilities.

3/2022 to Present
Vice President, Environmental Services and Land Management
Primary responsibility for leading the teams responsible for all aspects of compliance and permitting pertaining to environmental and land resource matters for Nevada Power and Sierra facilities.

CH2M HILL
6/2000 to 7/2015

Project and Program Management Assignments:

- Owner's Engineer and Construction Management (OECM), power client (2008 to 2014). Responsible for the planning, permitting, engineering and construction oversight services for wastewater and solid waste improvement and related closure projects at a coal-fired power plant.
- Program Design Manager, manufacturing client program, U.S. Nationwide (2011 to 2014). Responsibilities included establishing design teams, identifying delivery approaches, and ensuring best practices to deliver design-construction projects in an efficient manner for environmental remediation projects across the United States.
- Program Management for Greenfield Refined Products Pipeline (2007-2008). Assistant manager for preliminary engineering, cost estimating and permitting phase services for a grass-roots 400-mile refined products pipeline in the southwestern US.

Facilities Operations and Management Assignments:

- Interim Measures and Groundwater Response Action, Power Client, CA (2004-2005). Managed an immediate groundwater response action to establish hydraulic control of chromium-contaminated groundwater near a critical drinking water body in the

southwestern United States. Activities included construction of onsite batch treatment and temporary storage facilities, transportation, and offsite disposal.

- Facility Operations and Compliance Groundwater Extraction and Treatment System, Power Client, CA (2005-2006). Managed for the start-up and operation of a groundwater extraction and treatment system for chromium-contaminated water. The water was treated to rigorous permit limits allowing for onsite disposal into injection wells. Onsite staff included a site operations manager, up to eight full-time operators providing 24-hour/7-day per week operations, engineering staff focused on facility optimization, and environmental compliance specialists.

Other Project Management and Technical Experience

- Mine site closure and post-closure monitoring, Colorado (2006 to 2015)
- Groundwater permeable reactive barrier design, Michigan (2005).
- Municipal landfill closure, Federal facility, Wyoming (2000 to 2004).
- Groundwater investigations, Federal facility, Wyoming (2000 to 2004).
- Groundwater permeable reactive barrier pilot study, Texas (2002 to 2003).
- Groundwater treatment systems design, Federal facilities, Florida (2000 to 2005).

ERM-SOUTHWEST
6/1996 – 6/2000

Project Engineering Assignments

- Coal ash landfill closure design, Texas
- Calcium carbide waste disposal site closure design, Michigan.
- Groundwater slurry wall design, Texas
- Groundwater recovery trench design, Texas
- Hazardous and non-hazardous landfill closure design, Texas
- Corrective action management unit application and design Basis, Texas

EDUCATION

Master of Science in Agricultural Engineering, Texas A&M University, 1996

Bachelor of Science in Civil Engineering, University of Colorado, 1994

PROFESSIONAL REGISTRATIONS

Registered Professional Engineer – Civil Engineering - Arizona
Registered Professional Engineer – Civil Engineering - Nevada
Registered Professional Engineer – Civil Engineering - Texas

EXHIBIT JOHNS-DIRECT-2

EXHIBIT JOHNS DIRECT-2

NAVAJO GENERATION STATION CLOSURE COSTS WITHOUT CARRYING CHARGES
BY PROJECT INCLUDED IN ACCOUNT 182397 REGULATORY ASSET
DECEMBER 2019 THROUGH DECEMBER 2022 AND FORECASTED COST THROUGH MAY 2023

Ln No	(a) Activity Description	(b) 2019	(c) 2020	(d) 2021	(e) 2022	(f) Total	Ln No
1	**Decommissioning & Demolition**						1
2	0502 Pwr Blck D&D	68,993.16	2,571,584.45	2,615,167.18	2,101,419.58	7,357,164.37	2
3	0503 Pwr Blck Salv		(67,913.30)	(2,054,574.96)	(915,531.65)	(3,038,019.91)	3
4	1002 Asset Rec Slvg	9,969.84	(99,829.18)	(92,779.85)	(15,653.69)	(198,292.88)	4
5	0209 D&D Salv	1,090.33	(1,560.04)			(469.71)	5
6	**SUBTOTAL**	**80,053.33**	**2,402,281.93**	**467,812.37**	**1,170,234.24**	**4,120,381.87**	6
7	**Earthwork, Ponds, and Landfill Closures**						7
8	0802 Earthwk Sit Rst		21,886.08	250,699.72	2,015,960.24	2,288,546.04	8
9	0203 Pnd LF CY BP		(18,097.08)			(18,097.08)	9
10	0801 Pnd Clsr Decon	14,613.09	165,353.30	12,177.13	5,679.47	197,822.99	10
11	0702 CCR Lndfill D&D		3,120.47	97,312.67	1,817,901.23	1,918,334.37	11
12	0701 CCR Lndfill Decn		1,175.40	39.97		1,215.37	12
13	**SUBTOTAL**	**14,613.09**	**173,438.17**	**360,229.49**	**3,839,540.94**	**4,387,821.69**	13
14	**Other Decommissioning Costs**						14
15	0602 Catenary D&D	364.90	172,720.48	74,876.95	7,851.81	255,814.14	15
16	0603 Catenary Salv		17,016.84	276.59	(6,292.41)	11,001.02	16
17	1701 RAS Decom		65,913.17	39,155.12	1,528.37	106,596.66	17
18	1702 RAS D&D SRP SPT		2,787.84	43,099.35	(1,149.01)	44,738.18	18
19	**SUBTOTAL**	**364.90**	**258,438.33**	**157,408.01**	**1,938.76**	**418,150.00**	19
20	**Site Services and Site Monitoring Costs**						20
21	0901 Site Svcs Agt	28,166.53	89,040.37	21,972.67	12,165.30	151,344.87	21
22	0903 Site Svcs D&D	75,434.51	976,748.83	601,003.51	534,017.46	2,187,204.31	22
23	1301 Perched Wtr		28,873.82	5,086.84	17,187.35	51,148.01	23
24	1401 Post Retire Mntr	32.37	10,797.55	18,268.28	12,781.06	41,879.26	24
25	0207 Perched Wtr	474.71	(1,369.00)	(0.87)		(895.16)	25
26	**SUBTOTAL**	**104,108.12**	**1,104,091.57**	**646,330.43**	**576,151.17**	**2,430,681.29**	26
27	**Decommissioing Oversite and Planning**						27
28	1101 Prog Mgr & Spt		675,725.84	650,705.70	614,716.47	1,941,148.01	28
29	1201 Retire Oversite	13,828.22	181,745.02	97,378.39	92,175.32	385,126.95	29
30	0204 SRP DDDR Spt	2,834.38	(3,309.52)			(475.14)	30
31	0210 2019 Close Plan		(1,305.96)	(8.98)		(1,314.94)	31
32	0219 U3 Shutdown		(11,456.78)			(11,456.78)	32
33	1802 Spt Pndemic Cost		86,265.59	(1,922.67)		84,342.92	33
34	1501 Record & Doc	3,388.60	113,602.61	4,924.59		121,915.80	34
35	1502 Hist Lgcy Spt		3,124.09	4,439.10		7,563.19	35
36	1504 Culture Mitigate	187.69	1,025.29	55.94		1,268.92	36
37	1505 Spt Close Actns	1,105.30	15,906.84	(147.70)	1,368.50	18,232.94	37
38	1506 Ltgte Spt		484.13			484.13	38
39	1508 Other SRP Spt	175,250.80	60,658.51	25,512.95	31,911.44	293,333.70	39
40	0102 Lgl Consult	164.80	883.90	(6.66)		1,042.04	40
41	**SUBTOTAL**	**196,759.79**	**1,123,349.56**	**780,930.66**	**740,171.73**	**2,841,211.74**	41
42	**Extension Lease and Related Costs**						42
43	0301 Lease Pymts	205,660.00	231,936.69	228,253.86	240,236.60	906,087.15	43
44	1601 Asst Retent Pay	2,066,261.50				2,066,261.50	44
45	0104 Empl Ret	201,297.23	4,393.62			205,690.85	45
46	**SUBTOTAL**	**2,473,218.73**	**236,330.31**	**228,253.86**	**240,236.60**	**3,178,039.50**	46
47	**End of Life and True Up Costs**						47
48	Stranded Diesel Inventory	241,636.54				241,636.54	48
49	Stranded Materials & Supplies Inventory	(202,645.00)				(202,645.00)	49
50	Coal True-Up After Retirement	(34,940.19)				(34,940.19)	50
51	SRP Invoice Adjustments Prior Period	(40,814.54)				(40,814.54)	51
52	Navajo GS Retirement		2,880.00			2,880.00	52
53	AP [NV Energy external support]		2,520.00			2,520.00	53
54	2017 - 2019 NGS Load Audit Adj			(110,777.02)		(110,777.02)	54
55	**SUBTOTAL**	**(36,763.19)**	**5,400.00**	**(110,777.02)**	**-**	**(142,140.21)**	55
56	**TOTAL DECOMMISSIONING COSTS THROUGH DECEMBER 2022**	**2,832,354.77**	**5,303,329.87**	**2,530,187.80**	**6,568,273.44**	**17,234,145.88**	56
57							57
58							58
59					**NGS LEGACY BALANCE (FL90NP102A)**	**18,703.81**	59
60							60
61							61
62				**TOTAL NAVAJO COSTS DECEMBER 2019 THROUGH DECEMBER 2022, EXCLUDING CARRYING CHARGES**		**17,252,849.69**	62
63							63
64							64
65							65
66					**FORECASTED COST DURING CERTIFICATION PERIOD**	**2,492,892.21**	66
67							67
68							68
69				**TOTAL NAVAJO COSTS DECEMBER 2019 THROUGH MAY 2023, EXCLUDING CARRYING CHARGES**		**19,745,741.90**	69
70							70

EXHIBIT JOHNS-DIRECT-3

RECEIVED
FEB 19 2008
ENVIRONMENTAL PROTECTION

NEVADA DIVISION OF ENVIRONMENTAL PROTECTION
ADMINISTRATIVE ORDER ON CONSENT

RECEIVED
FEB 22 2008
ENVIRONMENTAL PROTECTION

Reid Gardner Station

TABLE OF CONTENTS

NEVADA DIVISION OF ENVIRONMENTAL PROTECTION ADMINISTRATIVE ORDER ON CONSENT

This Administrative Order on Consent ("AOC") is made and entered into this 20th day of February, 2008, by and among (i) the State of Nevada, Department of Conservation and Natural Resources, Division of Environmental Protection (the "Division"), and (ii) Nevada Power Company, as the owner and operator of Reid Gardner Station ("RGS") Units Nos. 1, 2, and 3 and as the co-owner and Operating Agent for Unit No. 4 ("NPC"). NPC and the Division are referred to collectively herein as the "Parties."

I. BACKGROUND

1. The Legislature of the State of Nevada has designated the Division as the agency empowered to administer and enforce Nevada's Environmental Laws, including, but not limited to, water pollution control laws, Nevada Revised Statutes ("NRS") §§ 445A.300 to 445A.730, inclusive, Nevada's hazardous waste disposal laws, NRS §§ 459.400 to 459.600 inclusive, and Nevada's Air Pollution Control laws, NRS §§ 445B.230 to 445B.640, inclusive.

2. NPC is the owner and operator of Units Nos. 1, 2 and 3 of RGS. NPC entered into the "Participation Agreement Reid Gardner Unit No. 4" (the "Participation Agreement") with the California Department of Water Resources ("CDWR") dated July 11, 1979, whereby CDWR and NPC jointly own Unit No. 4 of RGS. The Participation Agreement further designates NPC as the Operating Agent of Unit No. 4.

3. RGS has a number of raw water storage ponds, process water evaporation ponds, and fly ash settling ponds. Process water, which has been used beyond the treatable limits, is routed to onsite ponds for evaporation. Waste management units ("WMUs") are present throughout the site and surrounding area. Approximately 150 monitoring wells have been constructed to monitor the shallow, intermediate, and deeper groundwater conditions on and near the site. Currently, regular groundwater monitoring of approximately 75 monitoring wells occurs on a quarterly schedule. Site characterization and groundwater monitoring activities have focused on pollution conditions attributable to the operation of current and historic wastewater ponds, various WMUs, and other site-related activities. NPC has

implemented source control methods including without limitation salt removal and pond lining on most of the ponds, interim measures including construction and operation of a groundwater collection system south of Ponds D & E and north of the mesa, and long-term Corrective Action measures including the construction and operation of a diesel recovery system and Pond 4-A groundwater treatment system. The diesel recovery system has been in operation since 1988 and was upgraded in 2003. The diesel recovery system continues to operate in the eastern portion (power generation area) of the site recovering diesel and contaminated groundwater attributable to operation of large onsite aboveground storage tanks ("ASTs"). The Pond 4-A groundwater treatment system and related Corrective Action activities were designed to be implemented in phases. The Pond 4-A groundwater treatment system was installed and tested during development of this AOC.

Environmental contaminants beneath portions of the RGS facility and surrounding properties have been revealed by characterization and other work activities. Areas of known Releases of Environmental Contaminants from the RGS facility onto adjacent property include, but are not limited to, areas of Hogan Wash, property north of Pond 4A, property east of the power generation units, property north and east of WMU-4 (Mesa Landfill), and property south of WMU-4. Environmental contaminants identified at the RGS facility include, but are not limited to, elevated concentrations of total dissolved solids ("TDS"), sulfate, chloride, dissolved metals, volatile organic compounds ("VOCs"), and petroleum hydrocarbons.

4. This AOC governs the performance and/or completion of Environmental Contaminant characterization, the screening and selection of Corrective Action, and the implementation and long-term Operation and Maintenance of Division-approved Corrective Action concerning Pollution Conditions at the Site.

II. JURISDICTION

The Division has jurisdiction over this matter pursuant to NRS Chapter 445A. This AOC is issued under the authority of NRS § 445A.690. NPC has consented to the Division's jurisdiction over NPC and its jurisdiction to enter this AOC. NPC shall not challenge the terms of this AOC or the Division's jurisdiction to enter and enforce this AOC; however, NPC does not waive its right to challenge the Division's interpretation of any terms or conditions of this AOC through Dispute Resolution in Section XX (Dispute Resolution).

III. PARTIES BOUND

1. The provisions of this AOC shall apply to and be binding upon the Division of Environmental Protection, upon NPC and upon their successors and assigns.

2. Any change in ownership or corporate status of RGS or NPC including, but not limited to, any transfer of assets of real or personal property, or a portion of the Site, shall in no way alter NPC's responsibilities under this AOC, provided that, should NPC transfer ownership or operation of the Site, NPC may transfer its obligations under this AOC and may request the Division to look solely to the transferee for the performance of NPC's obligations hereunder. Any such request shall be in writing and be accompanied by an explanation of the transferee's capability to fulfill the obligations of NPC. The Division shall not unreasonably withhold its approval of a request by NPC pursuant to this Section.

3. In the event that NPC proposes to sell or transfer all or a portion of the Site, or any real property subject to this AOC, NPC shall, prior to such sale or transfer, provide written notice to such purchaser or transferee of the existence and terms of this AOC and status of the Work. NPC shall also obtain, and provide to the Division a copy of a written undertaking (approved in advance by the Division) from any purchaser in connection with such sale or transfer that said purchaser will comply with the foregoing notice requirements in connection with any subsequent transfer of such real property.

IV. DEFINITIONS

Unless otherwise expressly provided herein, terms used in this AOC that are defined in Nevada Law or in regulations promulgated under Nevada Law shall have the meaning assigned to them in Nevada Law or in such regulations. Whenever terms listed below are used in this AOC or in the appendices attached hereto and incorporated hereunder, the following definitions shall apply:

"Administrator" means the Administrator of the Nevada Division of Environmental Protection.

"Administrative Order on Consent" or "AOC" means this agreement and all appendices attached hereto, and Division-approved deliverables, amendments, modifications, and items incorporated by reference as provided in Section XXVII (such section titled "Incorporation and

Enforceability of Appendices or Referenced Materials"). In the event of conflict between this agreement and any appendix, this Agreement shall control.

"CEM" means a Certified Environmental Manager certified by the State of Nevada as defined in NAC 459.9704.

"CERCLA" means the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended, 42 U.S.C. §§ 9601 *et. seq.*

"Community Relations Plan" means a document that identifies stakeholders and proposes work to keep the identified stakeholders informed on the progress of the Corrective Action being conducted at the site.

"Contractor" means any entity or person, including any contractor, subcontractor, consultant, firm or laboratory, retained by NPC or the Division to conduct or monitor any portion of the work performed pursuant to this AOC.

"Corrective Action" means those activities, except for Operation and Maintenance, to be undertaken by NPC to implement the Scope of Work, final Corrective Action Design, Corrective Action Plan, and other plans approved by the Division, which are designed to provide a long-term remedy to minimize the potential exposure to Environmental Contaminants.

"Corrective Action Alternative Study" means the document of the same name developed pursuant to the Scope of Work and approved by the Division and any amendments thereto including remediation alternatives evaluated using appropriate feasibility studies.

"Corrective Action Plan" means the document of the same name developed pursuant to the Scope of Work and approved by the Division and any amendments thereto, including the final plans and specifications for the Corrective Action.

"Corrective Action Design" means those activities to be undertaken by NPC to develop the final plans and specifications for the Corrective Action.

"Corrective Action Standards" shall mean the cleanup standards and other measures that, when met, reflect achievement of the goals of the Corrective Action, as further described in Section XIV (such section titled "Corrective Action Performance Standards").

"Corrective Action Waste" means a Waste Material that is generated as a result of any remedial activity conducted pursuant to this AOC.

"Day" shall mean a calendar day; however, if the day falls on a Saturday, Sunday, State, or federal holiday the date for compliance shall be the next calendar day that is not a Saturday, Sunday, State, or federal holiday.

"Deliverable" means, without limitation, any Work plan, report, progress report, plan, data, document, information, submittal, obligation, permit application, Corrective Action Alternative Study, or Corrective Action Plan, which NPC is required to submit to the Division under the terms of this AOC or other document further defined by the Division as a Deliverable.

"Division" means the State of Nevada, Department of Conservation and Natural Resources, Division of Environmental Protection, or its successor department or agency of the State of Nevada.

"Effective Date" shall be the effective date of this AOC as provided in Section XXXIV ("Effective Date").

"Effective Period" means the period of time between the Effective Date and the date upon which this AOC terminates as specified in Section XXXV ("Termination").

"Engineering Controls" means any designed, installed, and/or constructed component or facility required by the Division that minimizes the potential for human and Environmental exposure to Environmental Contaminants and that is necessary to achieve the Corrective Action Standards associated with a selected Corrective Action.

"Environment" means air, land (including subsurface strata), and water (including groundwater) or any combination or part thereof.

"Environmental" means of or relating to the air, land (including subsurface strata), and water (including groundwater) or any combination or part thereof.

"Environmental Commission" means the Nevada State Environmental Commission as defined by NRS §§ 445B.200 to 445B.245, inclusive.

"Environmental Contaminant" means any material, substance, or waste regulated by any Environmental Law.

"Environmental Law(s)" means each federal and State law and implementing regulations promulgated there under relating in any way to Environmental pollution or the protection of the Environment or the Release of any Environmental Contaminant into the Environment including, without limitation, the Nevada Water Pollution Control Law, NRS §§ 445A.010 to 445A.730, inclusive, the Nevada Solid Waste Disposal Law, NRS §§ 444.440 to 444.645, inclusive, the Nevada Hazardous Waste Disposal Law, NRS §§ 459.400 to 459.652, inclusive, the Nevada Air Pollution Control Law, NRS §§ 445B.230 to 445B.640, inclusive, the Nevada Underground Storage Tank Law, NRS §§ 459.800 to 459.856, inclusive, the Nevada Radiation Control Law, NRS §§ 459.010 to 459.290, inclusive, the Clean Air Act, 42 U.S.C. §§ 7401 to 7671q, inclusive, the Federal Water Pollution Control Act, 33 U.S.C. §§ 1251-1387, the Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act, 42 U.S.C. §§ 6901-6992k, the Comprehensive Environmental Response, Compensation, and Liability Act, 42 U.S.C. §§ 9601- 9675, and the Toxic Substances Control Act, 15 U.S.C. §§ 2601-2692, each as may be amended from time to time.

"EPA" means the United States Environmental Protection Agency or its successor department or agency.

"Institutional Control" means any non-engineered measure or instrument such as an administrative and/or legal control (e.g. covenant, easement, well drilling prohibition, deed restriction, title recordation, servitude) required by the Division that minimizes the potential for human and Environmental exposure to Environmental Contaminants by limiting land or resource use. Institutional Controls include Environmental covenants as created by Senate Bill 263 (2005).

"Interest" means the current Federal funds rate as set by the Federal Reserve Board plus two percent (+2%), compounded monthly, but in no case will be less than five percent (5%) annually or greater than twelve percent (12%) annually. The rate can currently be found on the Federal Reserve Board's internet website at www.federalreserve.gov\FOMC\fundsrate.htm.

"NAC" means the Nevada Administrative Code or its successor codification of rules and regulations.

"NFA" means No Further Action

"NPC" shall have the meaning assigned to it in the introductory paragraph of this AOC.

"NRS" means the Nevada Revised Statutes or its successor codification.

"Operation and Maintenance" or "O & M" shall mean all activities required to maintain the effectiveness of the Corrective Action as required under the Operation and Maintenance Plan approved or developed by the Division pursuant to this AOC and the Scope of Work.

"Oversight Costs" means all costs reasonably incurred by the Division for oversight of this AOC with NPC, pursuant to Section XVII ("Reimbursement of Division Oversight Costs").

"Parties" shall mean the Nevada Division of Environmental Protection and NPC.

"Policies and Guidance" means the policies and guidance documents issued by the Division or EPA in implementing Environmental Laws.

"Pollution Conditions" means the conditions resulting from the Release of Environmental Contaminants at any time at or from the Site, above, on, into, under or upon land, soil, sediments, structures, atmospheres, or any natural or artificial waters including but not limited to: (1) all rivers, streams, lakes, ponds, washes, impounding reservoirs, seeps, springs, wetlands, marshes, watercourses, waterways, wells, irrigation systems and drainage systems; (2) all bodies or accumulations of water whether on the surface or underground; and (3) groundwater.

"RCRA" shall mean the Solid Waste Disposal Act, as amended, 42 U.S.C. §§ 6901 et seq. (also known as the Resource Conservation and Recovery Act).

"Receptor" means any appropriate and representative population, community or habitat of any biological organism (including humans, animals and plants), which is or may be affected by the Releases of Environmental Contaminants at or from the Site or Pollution Conditions.

"Records" mean all (1) Deliverables and (2) documents in the possession of NPC (including without limitation its officers, directors, and employees) and its consultants and

Contractors that are required by this AOC.

"Registered Professional Engineer" means a person who, by reason of his professional education and practical experience, is granted a license by the Nevada Board of Professional Engineers and Land Surveyors to practice professional engineering, subject to NRS §§625.005 to 625.590, inclusive.

"Release" means any past or present spilling, leaking, pumping, pouring, emitting, emptying, discharging, injecting, escaping, leaching, migrating, dumping, dispersal or disposing of any Environmental Contaminant into the Environment (including the abandonment or discarding of drums, barrels, containers, and other closed receptacles containing any Environmental Contaminant)

"Remedy" means all Response Actions implemented to provide for long-term Corrective Actions and which are designed to protect human health or welfare and the Environment at or related to the Site.

"Response Action" mean Corrective Actions, Institutional Controls, Engineering Controls, Operation and Maintenance, Interim Measures (as defined in Section VIII), and emergency response conducted for the remediation of Environmental Contaminants at the Site.

"Site" means all that certain land, structures, other appurtenances, and improvements described in Appendix A.

"State" shall mean the State of Nevada, including, as appropriate, its agencies, departments, political subdivisions, agents, and employees.

"Scope of Work" shall mean the statement of work as set forth in Appendix B to this AOC and any modifications made in accordance with this AOC.

"Sub-Area" shall mean any area on or off the Site that has been impacted by Waste Material and/or Environmental Contaminants originating from the Site that may be considered hydrologically, geographically, or otherwise separate from other areas of the Site.

"Supervising Contractor" shall mean the principal contractor retained by NPC to supervise and direct the implementation of portions of the Work under this AOC that require

the use of a Contractor.

"Waste Material" shall mean any discarded material, including solid, liquid, or contained gaseous material, that is (1) any "hazardous substance" under Section 101(14) of CERCLA, 42 U.S.C. § 9601(14) and NRS § 459.429; (2) any "pollutant" or "contaminant" under Section 101(33) 42 U.S.C. § 9601(33) and NRS §§ 445A.325, 445A.400; (3) any "solid waste" under Section 1004(27) of RCRA, 42 U.S.C. § 6903(27) and NRS § 444.490; and (4) any "hazardous material" under NRS § 459.428 that contributes or has contributed to the Pollution Conditions at the Site unless otherwise excepted by law.

"Work" shall mean all activities regarding Pollution Conditions that NPC is required to perform under this AOC, including but not limited to Corrective Action, Interim Measures (as defined in Section VIII), emergency response, and Institutional Controls.

V. STATEMENT OF PURPOSE

1. The objectives of the Parties in entering into this AOC are to protect human health or welfare and the Environment at and near the Site by the design and implementation of Response Actions at or near the Site by NPC, to reimburse the Division's Oversight Costs, to resolve the potential claims of the State against NPC as provided in this AOC, and to ensure compliance with applicable Environmental Laws.

2. This AOC governs the performance and/or completion of Environmental Contaminant characterization, the screening and selection of Corrective Action(s) and other Response Actions, and the implementation and long-term Operation and Maintenance of Division-approved Corrective Action(s) concerning Pollution Conditions.

3. This AOC supersedes the following administrative orders and Division requests:

a. The Division issued "Finding of Alleged Violation and Administrative Order No. 040191W1" in April 1991 because NPC had not applied for and obtained water pollution control permits for wastewater ponds and dewatering activities at the RGS. NPC complied with all requirements of this Order in June 1991.

b. The Division issued "Finding of Alleged Violation and Administrative Order No. NV052797W1" to NPC in May 1997 for discharging pollutants to waters of the state without authorization. Four of the six requirements in this Order are complete. The remaining

two, relating to investigation and cleanup of groundwater contamination, will be superseded by this AOC.

c. The Division issued "Finding of Alleged Violation and Administrative Order No. NV083199W1" to NPC in August 1999 for discharging pollutants to waters of the state without authorization. This Order was replaced by National Pollutant Discharge Elimination System ("NPDES") Permit No. NEV91022. NPC is still operating under this NPDES permit.

4. By entering into this AOC the Division and NPC recognize the actions undertaken by NPC in accordance with this AOC do not constitute an admission of liability, and NPC does not admit, and retains the right to controvert in any subsequent proceedings other than to implement or enforce this AOC, the validity of any determination made by the Division in connection with entering into this AOC.

VI. GENERAL PROVISIONS

1. Commitments by the Nevada Power Company. NPC, upon written notice from the Division, shall finance and perform the Work in accordance with this AOC, the Scope of Work, and all Work plans, other plans, standards, specifications, and schedules set forth herein or developed by NPC and approved by the Division pursuant to this AOC. NPC shall also reimburse the Division for Oversight Costs as provided in this AOC.

2. Compliance with Applicable Law. All activities undertaken by NPC pursuant to this AOC shall be performed in accordance with the requirements of all applicable federal and State laws and regulations. NPC must also comply with the Scope of Work.

3. Permits.

a. Where any portion of the Work requires a federal or State permit or approval, NPC shall submit timely and complete applications and take all other actions necessary to obtain all such permits or approvals.

b. NPC may seek relief under the provisions of Section XIX ("Force Majeure") of this AOC for any delay in the performance of the Work resulting from a failure to obtain, or a delay in obtaining, any permit required for the Work.

c. This AOC is not, and shall not be construed to be, a permit issued pursuant to any federal or State statute or regulation.

4. Notice to Successors-in-Title.

a. With respect to any property owned or controlled by NPC that comprises a part of the Site, within thirty (30) days after the Effective Date of this AOC, NPC shall submit to the Division for review and approval a notice to be filed with the Recorder's Office, Clark County, State of Nevada, in a form and substance reasonably satisfactory to the Division, which shall provide notice to all successors-in-title that the property(ies) is(are) part of the Site, that the Division has approved a Remedy, or will select a Remedy, for the Site and that potentially responsible Parties have entered into an AOC requiring implementation of the Remedy. Such notice(s) shall identify where a copy of this AOC may be obtained. NPC shall record the notice(s) within thirty (30) days of the Division's approval of the notice(s) and shall provide the Division with a certified copy of the recorded notice(s) within thirty (30) days of recording such notice(s).

b. In the event of any conveyance of any property interest within the Site, including but not limited to fee interest, leasehold interests, and mortgage interests, NPC's obligations under this AOC, including, but not limited to, its obligation to provide or secure access and Institutional Controls, as well as to abide by such Institutional Controls, pursuant to Section XI (such section titled "Site Access and Institutional Controls") of this AOC, shall continue to be met by NPC. In no event shall the conveyance, release or other transfer of any interest in the Site affect the liability of NPC to comply with all provisions of this AOC, absent the prior written consent of the Division pursuant to Section III, Paragraph 2.

VII. PERFORMANCE OF THE WORK BY THE NEVADA POWER COMPANY

1. NPC shall submit, receive approval for and likewise implement, as appropriate, Deliverables, consistent with the requirements of the Scope of Work attached as Appendix B and incorporated by reference.

2. Upon approval by the Division, Deliverables shall be incorporated into and become enforceable under this AOC.

3. Modification of the Scope of Work or related Deliverables.

a. If the Division determines that modification to the Work specified in the Scope of Work and/or in other Deliverables developed pursuant to the Scope of Work is necessary to achieve and maintain the Corrective Action Standards or to carry out and maintain the effectiveness of the Remedy, the Division may require that such modification be

incorporated in the Scope of Work and/or such Deliverables provided; however, that a modification may only be required pursuant to this Paragraph to the extent that it is consistent with the scope of the Remedy selected.

b. If NPC objects to any modification determined by the Division to be necessary pursuant to this Paragraph, they may seek dispute resolution pursuant to Section XX (such section titled "Dispute Resolution"). The Scope of Work and/or related Deliverables shall be modified in accordance with final resolution of the dispute.

c. NPC shall implement any Work required by any modifications incorporated in the Scope of Work and/or in Deliverables developed pursuant to the Scope of Work in accordance with this Paragraph.

d. Nothing in this Paragraph shall be construed to limit the Division's authority to require performance of further Response Actions as otherwise provided in this AOC.

4. All Work shall be performed in compliance with the health and safety plan as required in the Scope of Work.

5. NPC shall continue to implement the Corrective Action and O & M until the Corrective Action Standards are achieved and for so long thereafter as is otherwise required under this AOC.

6. NPC acknowledges and agrees that nothing in this AOC, the Scope of Work, or the associated Deliverables constitutes a warranty or representation of any kind by the State that compliance with the Work requirements set forth in the Scope of Work and the Work plans will achieve the Corrective Action Standards.

7. NPC shall, prior to any off-Site shipment of Corrective Action Waste from the Site to a waste management facility, provide written notification to the Division Project Coordinator of such shipment of Corrective Action Waste.

a. In the event that any Corrective Action Waste is destined for an out-of-state facility, NPC shall provide written notification to the Division Project Coordinator.

b. NPC shall include in the written notification the following information, where available: (1) the name and location of the facility to which the Corrective Action Waste is to be shipped; (2) the type and quantity of the Corrective Action Waste to be shipped; (3) the

expected schedule for the shipment of the Corrective Action Waste; and (4) the method of transportation. NPC shall notify the Division Project Coordinator of major changes in the shipment plan, such as a decision to ship the Corrective Action Waste to another facility.

c. NPC shall provide the information required by this Paragraph as soon as practicable after the award of a waste management agreement or contract but in no event, later than 30 days before the Corrective Action Waste is actually shipped (unless the Corrective Action Wastes must be shipped sooner in order to comply with applicable law).

VIII. INTERIM MEASURES

1. If, at any time during the Effective Period of this AOC, the Division determines, based upon consideration of any of the factors specified in Paragraph 2 below, that any Pollution Conditions may pose an imminent and substantial hazard to human health, welfare, or the Environment, the Division may notify NPC in writing of the measure(s) the Division has determined need to be developed and implemented by NPC to mitigate the imminent and substantial hazard ("Interim Measure(s)"). If deemed appropriate by the Division, the identification of such Interim Measure(s) may be deferred pending the collection, by NPC, of additional data or information requested by the Division.

2. The following factors, among others, may be considered by the Division in determining whether any Interim Measure(s) should be required:

a. the time required to develop and implement a final Remedy for Pollution Conditions;

b. actual or potential exposure of nearby Receptors to Environmental Contaminants from Pollution Conditions;

c. actual or potential contamination of drinking water supplies or sensitive ecosystems by Pollution Conditions;

d. further degradation of the Environment, which may occur because of Pollution Conditions if an Interim Measure is not implemented expeditiously.

e. the presence of Environmental Contaminants in drums, barrels, tanks, or other bulk storage or disposal containers or facilities at the Site that pose a threat of Release;

f. weather conditions that may cause Environmental Contaminants to be Released;

risks of fire or explosion, or potential for exposure to Environmental Contaminants as a result of an accident or failure of a container, facility, or handling system that may cause a Release;

g. any other factor relating to Pollution Conditions that may indicate the existence of an imminent and substantial threat to human health, welfare, or the Environment.

3. If, at any time during the Effective Period of this AOC, NPC determines that information or data has been identified or developed indicating that any Pollution Conditions pose a potential threat to human health, welfare, or the Environment of a degree that reasonably requires the prompt development and implementation of an Interim Measure(s), NPC shall so notify the Division (1) orally within twenty-four (24) hours, and (2) in writing within three (3) days following the making of such determination, summarizing the immediacy and magnitude of the potential threat and explaining how NPC intends to address those Pollution Conditions.

4. Within fourteen (14) days following any requirement by the Division regarding an Interim Measure that is the subject of Division notification pursuant to Paragraph 1, NPC shall submit to the Division a Work plan for the development and implementation of the Interim Measure(s) ("Interim Measure(s) Work Plan") as identified in such notification. Each Interim Measure(s) Work Plan is subject to approval by the Division, and each Interim Measure(s) Work Plan shall address, as appropriate and without limitation:

a. objectives of the Interim Measure(s);

b. technical approach;

c. engineering design and planning (including Division approval of all design plans and specifications);

d. schedule for development and implementation of the Interim Measure(s);

e. qualifications of personnel performing the development or implementation of the Interim Measure(s), including Contractor personnel;

f. health and safety planning;

g. data collection quality assurance, strategy, management, and analysis;

h. construction quality assurance including inspection activities, sampling requirements, documentation, and certification of construction consistent with Division-

approved designs;

i. Operation and Maintenance of the Interim Measure(s);

j. document/data submittals for Division approval; and

k. regular progress reporting during the development and implementation of the Interim Measure(s).

5. Interim Measure(s) shall, to the extent practicable, be consistent with the objectives of, and contribute to the performance of, any long-term Remedy at the Site.

6. Division approval of an Interim Measure(s) Work Plan and any Work undertaken by NPC pursuant thereto shall be governed by the other provisions of this AOC, including without limitation, the dispute resolution provisions of Section XX. In the case of a dispute related to an Interim Measure, the timeframes outlined in Section XX shall be shortened by one-half of the time allowed. The Division is entitled to take over the performance of an Interim Measure pursuant to Paragraph 13 (such paragraph titled "Work Takeover") of Section XXII (such section titled "Covenants by the Division and Reservation of Rights").

IX. PROJECT COORDINATORS AND KEY PERSONNEL

1. Designation of Project Coordinator. NPC and the Division shall each designate a Project Coordinator ("Project Coordinator") and Alternate Project Coordinator ("Alternate Project Coordinator") for the Site and will notify the Parties, in writing of the name, address and telephone number of such coordinators. The Project Coordinator shall be a representative of a team of individuals who have expertise to oversee implementation of the Scope of Work at or related to the Site. The Project Coordinator shall be responsible for overseeing the implementation of this AOC and for designating a person to act in his/her absence. The Division Project Coordinator will be the Division's designated representative for the Site. If a Project Coordinator or Alternate Project Coordinator initially designated is changed, the identity of the successor will be given to the other Party at least seven (7) days before the change occurs, unless impracticable, but in no event later than the actual day the change is made. NPC's Project Coordinator shall have the technical expertise sufficient to adequately oversee all aspects of the Work, or shall retain Key Personnel, as defined in Paragraph 3 of this Section, who have such expertise. He or she may assign other representatives, including other Contractors, to serve as a Site representative for oversight of performance of daily

operations during Site activities.

2. CEM Signature. All Work conducted for NPC by a Contractor shall be signed by a CEM and shall include the jurat language found in NAC 459.97285

3. For the purposes of this Section, the term "Key Personnel" is defined to mean those individuals who have primary responsibility for the direction of employees or subcontract personnel for major project tasks, outputs, or deliverables including, but not limited to, data collection, data interpretation, and report writing.

4. Unless the Division notifies NPC otherwise, the Division's Project Coordinator, Alternate Project Coordinator, and Emergency Contact shall be:

Project Coordinator

Staff Engineer III / RPE
Nevada Division of Environmental Protection
2030 E. Flamingo Rd, Suite 230
Las Vegas, NV 89119
TL: 702-486-2850
FX: 702-486-2863

Alternate Project Coordinator

Remediation Branch Supervisor
Nevada Division of Environmental Protection
2030 E. Flamingo Rd, Suite 230
Las Vegas, NV 89119
TL: 702-486-2850
FX: 702-486-2863

Emergency Contact

Spill Reporting Number (Reportable releases per NAC 445A.347)
888-311-6337

5. Unless NPC notifies the Division otherwise, NPC's Project Coordinator, Alternate Project Coordinator, and Emergency Contact shall be:

Project Coordinator

Supervisor, Environmental Services
Reid Gardner Generating Station MS #77
P.O. Box 279
501 Wally Kay Way
Moapa, NV 89025
TL:702-579-1389
FX: 702-579-1885

Alternate Project Coordinator

Manager, Environmental Services, Coal
Nevada Power Company
6226 West Sahara Avenue, MS #30
Las Vegas, NV 89146

TL: 702-367-5767
FX: 702-227-2051

Emergency Contact

Environmental Services 24-Hour Emergency Response Number
702-598-7352

6. The absence of the Division Project Coordinator from the Site shall not be cause for the stoppage of Work.

7. To the maximum extent practicable, all communications from NPC to the Division, which shall include without limitation all Deliverables, documents, reports, approvals and other correspondence concerning the activities performed pursuant to this AOC, shall be in writing and shall be directed to the Division Project Coordinator and a copy provided to the Division's Alternate Project Coordinator.

8. Communications from the Division to NPC shall be directed to the responsible corporate officer discussed in Section XII (such section titled "Reporting Requirements") or Section XXV (such section titled "Notices and Deliverables"), and copied to NPC's Project Coordinator.

9. Authority of the Division Project Coordinators.

a. The Division's Project Coordinator or Alternate Project Coordinator shall have the authority to halt any Work required by this AOC and to take any Emergency Response pursuant to Section XVI.

b. The Division may designate other representatives, including, but not limited to, State employees, and State Contractors and consultants, to observe and monitor the progress of any activity undertaken pursuant to this AOC.

10. Within thirty (30) days following the Effective Date of this AOC, and before the required Work begins, NPC shall notify the Division's Project Coordinator in writing of the names, titles and qualifications of any other Key Personnel, Contractors, and its personnel proposed to be used in carrying out the terms of this AOC. If Key Personnel or Contractors to be used to carry out the terms of the AOC are not known within the initial thirty (30) days of the Effective Date, NPC shall provide such notification of Key Personnel and Contractors to the Division at least thirty (30) days prior to their incorporation into performance of any Work, unless circumstances reasonably warrant shorter notice.

11. The qualifications of the Project Coordinator, Alternate Project Coordinator, and Key Personnel shall be subject to the Division's review and approval, for verification that such persons meet minimum technical background and experience requirements. The Division reserves the right to disapprove NPC Project Coordinator, Alternate Project Coordinator, or Key Personnel for good cause shown at any time during the Effective Period of this AOC. If the Division disapproves any Project Coordinator, Alternate Project Coordinator or Key

Personnel proposed by NPC to perform Work pursuant to this AOC, then NPC shall, within thirty (30) days after receipt from the Division of written notice of such disapproval, notify the Division in writing of the name, title, and qualifications of any replacement. The Division's disapproval under this Section shall be subject to review in accordance with Section XX ("Dispute Resolution") of this AOC.

12. During the Effective Period of this AOC, NPC shall notify the Division in writing of any changes or additions in the Key Personnel used to carry out the Work required by the AOC, providing their names, titles, and qualifications. The Division shall have the same right to approve changes and additions to such persons as it has hereunder regarding the initial notification.

13. Changes to personnel shall not be considered a modification to this AOC.

X. QUALITY ASSURANCE, SAMPLING, DATA ANALYSIS AND DATA AVAILABILITY

1. NPC shall use quality assurance, quality control, and chain of custody procedures for all characterization, treatability, design, compliance, monitoring, and risk assessment/closure samples consistent with current and applicable EPA Policies and Guidance.

2. Within the timeframe established by the schedule in the Scope of Work, NPC shall submit to the Division for approval, a Quality Assurance Plan ("QAP") for the Site that is consistent with the Scope of Work and applicable Policies and Guidance. Work plans shall reference and incorporate the Site QAP and, as applicable, contain Work plan-specific quality assurance/quality control ("QA/QC") and chain of custody procedures for all sampling, monitoring and analytical activities associated with the Work plan. Any deviations from the approved Site QAP and/or Work plan QA/QC procedures must be approved by the Division; must be documented, including reasons for the deviations, and must be reported in any applicable Deliverable.

3. If relevant to a proceeding, the Parties agree that validated sampling data generated in accordance with the QAP(s) and reviewed and approved by the Division shall be admissible as evidence, without objection, in any proceeding under this Agreement.

4. NPC shall ensure that all samples are collected and analyzed using Division approved procedures, accepted laboratory methods, and laboratories certified under Nevada

law. NPC shall use best efforts to ensure that its Contractor or contract laboratories obtain high quality data. NPC shall require that laboratories used for analysis, perform such analysis according to the latest approved edition of "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods" ("SW -846") or other methods deemed satisfactory by the Division. NPC shall submit any deviations from the protocols proposed in any Work plan to the Division for its approval thirty (30) days prior to the commencement of analyses, except in extraordinary circumstances. The Division may reject any data that does not meet the requirements of the approved Work plan or EPA analytical methods and may require re-sampling and additional analysis.

5. NPC shall ensure that laboratories NPC or NPC's Contractor(s) use for analyses participate in a QA/QC program that is deemed acceptable to the Division. As part of such a program, and upon request by the Division, NPC shall ensure that Division personnel and its authorized representatives are allowed access at reasonable times to all laboratories utilized by NPC in implementing this AOC. In addition, NPC shall ensure that such laboratories shall analyze all samples submitted by the Division for quality assurance monitoring. Such laboratories shall perform analyses of samples provided by the Division to demonstrate laboratory performance and the quality of analytical data. If the audit reveals deficiencies in a laboratory's performance or QA/QC, the Division may require re-sampling and additional analysis of any samples affected by the deficiencies.

6. Any deviations from the QAP must be approved by the Division, must be documented, including reasons for the deviations and must be reported in the applicable Deliverable.

7. The name(s), addresses, and telephone numbers of the analytical laboratories NPC proposes to use must be submitted to the Division for review and approval prior to Work being performed.

8. Upon request, NPC shall allow split or duplicate samples to be taken by the Division or its authorized representatives. NPC shall notify the Division not less than fourteen (14) days in advance of any sample collection activity unless the Division approves a shorter notice period, which approval shall not be unreasonably withheld. During sample collection activities conducted by NPC, the Division shall have the right to take any additional samples

that the Division deems necessary. Upon request, the Division shall allow NPC to take split or duplicate samples of any samples the Division takes as part of the oversight of NPC's implementation of the Work.

9. All final results of sampling, tests, modeling and other data generated by NPC, or on NPC's behalf pursuant to this AOC (not including raw data that has not been subject to QA/QC procedures), shall be submitted to the Division. NPC shall submit to the Division two (2) copies of the results of all sampling and/or tests or other data obtained or generated by or on behalf of NPC with respect to the Site and/or the implementation of this AOC unless the Division agrees otherwise. NPC shall make all raw data available to the Division for review on request, and shall submit such data to the Division on written request. The Division will provide to NPC validated data generated by the Division, unless it is exempted or prohibited from disclosure by any applicable federal or State law or regulation.

10. Notwithstanding any provision of this AOC, the Division hereby retains all of its information gathering and inspection authorities and rights, including enforcement actions related thereto, under any applicable statutes or regulations.

XI. SITE ACCESS AND INSTITUTIONAL CONTROLS

1. The Division, its Contractors, employees, and/or any duly designated Division representatives carrying out the authority of the Division shall have NPC's permission, at all reasonable times, upon notice to NPC's Project Coordinator, Alternate Project Coordinator, or Emergency Contact and in conformance with any health and safety requirements at the Site, to enter and freely move about the Site whether or not Work is being performed pursuant to this AOC for the purposes of, *inter alia:* (1) discussing the Work being performed under this AOC with NPC or relevant Contractor personnel; (2) inspecting conditions, activities, the results of activities, Records, operating logs, and contracts related to the Site or NPC and its Contractors pursuant to this AOC; (3) reviewing the progress of NPC in carrying out the terms of this AOC; (4) conducting such tests, sampling, or monitoring as the Division or its authorized representatives deem necessary; (5) using a camera, sound recording device or other documentary type equipment; (6) verifying the Records submitted to the Division by NPC; and (7) inspecting and copying all non-privileged Records, files, photographs, documents, sampling and monitoring data, and other writings or materials related to Work undertaken in carrying out

the requirements of this AOC consistent with the requirements of this AOC. Nothing herein shall be interpreted as limiting, waiving or otherwise affecting (1) the Division's right of entry or inspection under state or federal laws; (2) the Division's rights to require, or enforcement authority related to, Institutional Controls or Engineering Controls including any land or water use restrictions; (3) any attorney-client, work-product or other privilege with respect to any matter affecting NPC; or (4) NPC's right to seek confidential treatment of any matter pursuant to applicable law.

2. To the extent that the Site or any other property to which access is required for the performance of Work required under this AOC is owned or controlled by persons or entities other than NPC, NPC shall use best efforts pursuant to Paragraph 6 of this Section to obtain access to such property for NPC, and the Division and its authorized representatives, within thirty (30) working days after the date that the need for access becomes known to NPC. The Division may provide reasonable assistance to NPC in the event that any third-party property owner refuses to provide access.

3. NPC agrees to indemnify, defend and hold harmless the Division as provided in Section XVIII (such section titled "Indemnification"), for any and all claims arising from NPC's, or its officers', employees', agents' or Contractors' activities described in Paragraph 2 of this Section.

4. Nothing in this Section shall be construed to limit or otherwise affect NPC's liability and obligations with respect to any Release of Environmental Contaminant(s) or Pollution Condition(s).

5. If the Site, or any other property where Institutional Controls regarding land or water use restrictions are needed to implement this AOC, is owned or controlled by NPC, NPC shall, commencing on the Effective Date of this AOC, refrain from using the Site, or such other property on which Work is being performed in any manner that would interfere with or adversely affect the integrity or effectiveness of the Response Action (s) to be implemented pursuant to this AOC.

6. For purposes of this Section, "best efforts" shall include, at a minimum: (1) a certified letter from NPC to the present owners of such property requesting access agreements to permit NPC and the Division, including its authorized representatives, to access such

property, and the payment of reasonable compensation in consideration of granting access or access easements; (2) the payment of reasonable sums of money in consideration of any land or water use restriction, easements, covenants, Institutional Controls or agreements required by this Section; or (3) compliance with federal and state laws, regulations and policies addressing access, easements, covenants, Institutional Controls or agreements, including but not limited to such actions as are contemplated by NRS 459.930 (such section titled "Immunity from liability for certain persons for response actions and cleanup with respect to certain real property at which a hazardous substance has been or may have been released"). Any such access agreement(s) or restriction(s) shall be incorporated by reference into this AOC upon execution. NPC shall provide to the Division's Project Coordinator a copy of each such access agreement or restriction. In the event that any necessary agreement for access is not obtained within thirty (30) days following approval of any Work plan for which access is required, or following the date that the need for access became known to NPC, NPC shall notify the Division thereafter regarding both the efforts undertaken to obtain access and its failure to obtain such access agreement. The Division shall cooperate with NPC in obtaining access agreements or restrictions, but NPC shall pay any just compensation required for any agreements or restrictions as described herein. In the event that the Division obtains access, NPC shall undertake Division approved Work on such property. The Division may, as it deems appropriate, assist NPC in obtaining land or water use restrictions, either in the form of contractual agreements or in the form of easements, covenants, or Institutional Controls running with the land. NPC shall reimburse the Division in accordance with the procedures in Section XVII ("Reimbursement of Division Oversight Costs"), for all costs incurred, direct or indirect, by the Division in obtaining such access or land or water use restrictions including, but not limited to, the cost of attorney time.

7. Division officials, agents, employees, Contractors, subcontractors, or representatives shall be safety trained by NPC before entry to the Site and shall have any required safety equipment issued by NPC during the Site visit.

XII. REPORTING REQUIREMENTS

1. Beginning with the first full calendar quarter following the Effective Date, and throughout the Effective Period of this AOC, and in addition to any other requirement of this

AOC, NPC shall submit to the Division a written quarterly progress report. The report shall: (a) describe the actions which have been taken toward achieving compliance with this AOC during the previous quarter; (b) include a summary of all results of sampling and tests and all other data received or generated by NPC or its Contractors or agents in the previous quarter; (c) identify all Work plans, plans and other deliverables required by this AOC that were completed and submitted during the previous quarter; (d) describe all actions including, but not limited to, data collection and implementation of Work plans that are scheduled for the next quarter and provide other information relating to the progress of construction including, but not limited to, critical path diagrams, Gantt charts and Pert charts; (e) include information regarding percentage of completion, unresolved delays encountered or anticipated that may affect the future schedule for implementation of the Work, and a description of efforts made to mitigate those delays or anticipated delays; (f) include any modifications to the Work plans or other schedules that NPC has proposed to the Division or that have been approved by the Division; and (g) describe all activities undertaken in support of the Community Relations Plan during the previous quarter and those to be undertaken in the next quarter.

2. NPC shall submit quarterly progress reports to the Division by the twenty-eighth (28th) day of the month following the end of each calendar quarter. If requested by the Division, NPC shall also provide briefings for the Division, upon reasonable notice, to discuss the progress of the Work.

3. NPC shall notify the Division of any change in the schedule described in the quarterly progress report for the performance of any activity, including, but not limited to, data collection and implementation of Work plans, no later than fourteen (14) days prior to the performance of the activity.

4. NPC is expected to report any unexpected occurrence at the Site that is related to Work conducted in compliance with this AOC. Unexpected occurrences include, but are not limited to, interruptions of remediation, unusual or unanticipated malfunctions, upsets, interruptions, delays, slowdowns, accelerations, and other discoveries that are not subject to other reporting requirements in this AOC.

5. Upon the occurrence of any event that NPC is required to report, NPC shall, within 24 hours of discovery such event, orally notify the Division's Project Coordinator or

Alternate Project Coordinator if the Division's Project Coordinator is unavailable. If neither the Division's Project Coordinator nor Alternate Project Coordinator is available, then the Division's Chief of the Bureau of Corrective Actions shall be the point of contact. In no case will this Paragraph relieve NPC from complying with State reporting requirements contained in NAC § 445A.347 (such section titled "Notice Required") when any such reportable event occurs.

6. Within twenty (20) days of the discovery of such an event, NPC shall furnish to the Division a written report, signed by the Company's Project Coordinator, setting forth the events which occurred and the measures taken, and to be taken, in response thereto. Within thirty (30) days after completion of the measures taken in response to such an event, NPC shall submit a report setting forth all actions taken in response thereto.

7. NPC shall submit an original and at least two (2) copies of all Deliverables required by the Scope of Work or any other data or approved plans to the Division in accordance with the schedules set forth in such plans or the Scope of Work pursuant to the terms and conditions of this AOC. One copy shall be a paper copy and one copy shall be an electronic copy. The electronic copy shall be in a form acceptable to the Division. Deliverables shall be hand delivered, sent by certified mail - return receipt requested, sent by overnight parcel delivery service, or sent by verified facsimile transmission to the Division's Project Coordinator in accordance with Section XXV (such section titled "Notices and Deliverables").

8. All Deliverables and other documents submitted by NPC to the Division (other than the quarterly progress reports referred to above), which purport to document NPC's compliance with the terms of this AOC shall be signed and certified by a responsible corporate officer of NPC. A responsible corporate officer means: a president, secretary, treasurer, general manager, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision making functions for the corporation.

9. The certification required above shall be in the following form:

> I certify that this document and all attachments submitted to the Division were prepared under the direction or supervision of NPC in accordance with a system designed to gather and evaluate the information by appropriately

qualified personnel. Based on my inquiry of the person or persons who manage the system(s) or those directly responsible for gathering the information, or the immediate supervisor of such person(s), the information submitted and provided by NPC is, to the best of my knowledge and belief, true, accurate, and complete in all material respects. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Signature: _____
Name: _____
Title: _____
Company: _____
Date: _____

10. In addition, all Deliverables and other documents submitted by NPC to the Division that are required under Nevada Law to be prepared or submitted by a Certified Environmental Manager shall be signed and certified by the CEM responsible for the project. These Deliverables shall include the Jurat required by NAC 459.97285 and shall be in the following form:

I hereby certify that I am responsible for the services described in this document and for the preparation of this document. The services described in this document have been provided in a manner consistent with the current standards of the profession and to the best of my knowledge comply with all applicable federal, state, and local statutes, regulations, and ordinances. I hereby certify that all laboratory analytical data was generated by a laboratory certified by the NDEP for each constituent and media presented herein.

Signature: _____
Name: _____
Title: _____
Company: _____
Date: _____
EM Certificate Number: _____
EM Expiration Date: _____

XIII. DIVISION APPROVAL OF PLANS AND OTHER SUBMISSIONS

1. After review of any Deliverable, which is required to be submitted for approval pursuant to this AOC, the Division shall: (a) approve, in whole or in part, the Deliverable; (b) approve the Deliverable upon specified conditions; (c) disapprove, in whole or in part, the Deliverable, directing that NPC modify the Deliverable; or (d) any combination of the above.

The Division will notify NPC of the decision in writing within a reasonable time after submittal by NPC.

2. In the event of approval or approval upon conditions pursuant to Paragraph 1 (a) or (b), NPC shall proceed to take any action required by the Deliverable, as approved by the Division subject only to its right to invoke the dispute resolution procedures set forth in Section XX with respect to the conditions made by the Division. The Division retains its right to seek stipulated penalties, as provided in Section XXI in the event NPC fails to implement the approved Deliverable.

3. Upon receipt of a notice of disapproval pursuant to Paragraph 1, NPC shall, within fourteen (14) days or such longer time as specified by the Division in such notice, correct the deficiencies and resubmit the Deliverable for approval. Any stipulated penalties applicable to the Deliverable, as provided in Section XXI, may accrue during the 14-day period or otherwise specified period if NPC fails to correct the deficiency or fails to resubmit the Deliverable to the Division. If NPC submits an approvable Deliverable within the 14-day period or otherwise specified period, the Division will not assess stipulated penalties.

4. Notwithstanding the receipt of a notice of disapproval pursuant to Paragraph 1, NPC shall proceed, at the direction of the Division, to take any action required by any non-deficient portion of the Deliverable. Implementation of any non-deficient portion of a Deliverable shall not relieve NPC of any liability for stipulated penalties under Section XXI as to the deficient portion of the Deliverable, subject to Paragraph 3.

5. In the event that a resubmitted Deliverable, or portion thereof, is disapproved by the Division, the Division may again require NPC to correct the deficiencies, in accordance with the preceding Paragraphs, or the Division retains the right to develop the Deliverable. NPC shall implement any such Deliverable as developed by the Division, subject only to its right to invoke the dispute resolution procedures set forth in Section XX as to the portions developed by the Division.

6. If upon resubmission, a Deliverable is disapproved by the Division, NPC shall be deemed to have failed to submit such Deliverable timely and adequately unless NPC invokes the dispute resolution procedures set forth in Section XX and the Division's action is overturned pursuant to that Section. The dispute resolution provisions of Section XX and the

stipulated penalty provisions of Section XXI shall govern the implementation of the Work and accrual and payment of any stipulated penalties during a period of dispute resolution. If the Division's disapproval is upheld, stipulated penalties shall accrue for such violation from the date on which the initial submission was originally due.

7. All Deliverables required by the Division under this AOC shall, upon approval or development by the Division, be incorporated by reference into and made enforceable under this AOC. In the event the Division approves a portion of a Deliverable required by the Division under this AOC, the approved portion shall be enforceable under this AOC.

XIV. CORRECTIVE ACTION PERFORMANCE STANDARDS

1. The Corrective Action Design(s) required in the Scope of Work shall provide for design, construction, and implementation of the Remedy(ies). Upon their approval by the Division, the Corrective Action Design(s) shall be incorporated into and become enforceable under this AOC. Corrective Action Standards approved by the Division shall be incorporated into and become enforceable under this AOC.

2. NPC shall continue to implement the Remedy(ies) and Operations & Maintenance until the Corrective Action Standards are achieved and for so long thereafter as is otherwise required under this AOC.

XV. DETERMINATION OF COMPLETION

A. No Further Action.

1. If at any time NPC believes that sampling results, the performance of other Work or other circumstances demonstrate that, with respect to any portion of the Site, no further Response Actions are required or necessary to protect human health and the Environment, NPC may propose that the Division issue a written notice to that effect. The Division's disapproval of or failure to act upon (within a reasonable time) a proposal made under this Section may be subject to dispute resolution under Section XX.

2. In making any determination hereunder, the Division may consider within its statutory discretion any and all relevant factors including, without limitation:

a. existing and potential or planned land uses for such portion of the Site and Environmental and human exposure threats associated therewith;

b. whether the issuance of such written notice would preclude or significantly and adversely affect the investigation or Corrective Action of Environmental Contaminants at or associated with the Site;

c. the sampling data or other information and circumstances relied upon by NPC; and

d. applicable or relevant and appropriate environmental cleanup standards (including, without limitation, any Division Policies and Guidance regarding contaminated soil and groundwater remediation).

3. The issuance by the Division of a written determination of "No Further Action" hereunder shall not constitute or be construed as either: (1) a release, covenant not to sue, or any other limitation whatsoever on the authority of the Division to respond to subsequently-identified Environmental conditions at or associated with the Site; (2) a determination, decision or opinion regarding the suitability of any particular land use for the Site; or (3) a limitation on the Division's ability to require that Institutional Controls be recorded on the property with the Clark County Recorder's office.

B. Completion of Sub-Area Corrective Action.

1. Within ninety (90) days after NPC concludes that the Corrective Action Plan(s) for a Sub-Area has/have been fully performed and the Corrective Action Standards have been attained, NPC shall schedule and conduct a pre-determination inspection to be attended by NPC and the Division. If, after the pre-determination inspection, and within thirty (30) days of the inspection, NPC still believes that the Corrective Action(s) has/have been fully performed, that the Corrective Action Standards have been attained and that no further Work is necessary to protect human health and the Environment, NPC may propose that the Division acknowledge this status in writing. NPC shall submit such a proposal to the Division in writing, together with a report including data and analysis to support its opinion. In the report, a CEM and NPC's authorized representative shall state that the Corrective Action(s) has/have been completed in full satisfaction of the requirements of this AOC in accordance with certification requirements in Section XII ("Reporting Requirements"). The written report shall include as-built drawings signed and stamped by a professional engineer. Upon receipt of such proposal and report, the Division will review the documentation and take appropriate action to confirm

that the Work is complete pursuant to Section XIII (such section titled "Division Approval of Plans and Other Submissions"). The Division shall acknowledge this status in writing by providing NPC with a "No Further Action" letter. A determination of "No Further Action" regarding Corrective Action(s) shall not affect NPC's remaining obligations under this AOC.

2. If, after completion of the pre-determination inspection and receipt and review of the written report, the Division determines that the Corrective Action(s) or any portion thereof has/have not been completed in accordance with this AOC or that the Corrective Action Standards have not been achieved, the Division will notify NPC in writing of the activities that must be undertaken by NPC pursuant to this AOC to complete the Corrective Action(s) and achieve the Corrective Action Standards. The Division will set forth in the notice a schedule for performance of such activities consistent with the AOC and the Scope of Work or require NPC to submit a schedule to the Division for approval pursuant to Section VIII (such section titled "Division Approval of Plans and Other Deliverables"). NPC shall perform all activities described in the notice in accordance with the specifications and schedules established pursuant to this Paragraph, subject to its right to invoke the dispute resolution procedures set forth in Section XX.

C. Completion of the Work.

1. Within ninety (90) days after NPC concludes that all elements of the Scope of Work (including O & M and any long-term monitoring) have been fully performed, NPC shall schedule and conduct a pre-determination inspection to be attended by NPC and the Division. If, after the pre-determination inspection, NPC still believes that the Work has been fully performed and that no further Work is necessary to protect human health and the Environment, NPC may propose that the Division acknowledge this status in writing. NPC shall submit such a proposal to the Division in writing, together with a report including data and analysis to support its opinion. In the report, a CEM and NPC authorized representative shall state that the Work has been completed in full satisfaction of the requirements of this AOC in accordance with certification requirements in Section XII (such section titled "Reporting Requirements"). Upon receipt of such proposal and report, the Division will review the documentation and take appropriate action to confirm that the Work is complete pursuant to Section XIII (such section titled "Division Approval of Plans and Other Deliverables").

2. If, after review of the written report, the Division determines that any portion of the Work has not been completed in accordance with this AOC, the Division will notify NPC in writing of the activities that must be undertaken by NPC pursuant to this AOC to complete the Work. The Division will set forth in the notice a schedule for performance of such activities consistent with the AOC and the Scope of Work or require NPC to submit a schedule to the Division for approval pursuant to Section XIII (such section titled "Division Approval of Plans and Other Deliverables"). NPC shall perform all activities described in the notice in accordance with the specifications and schedules established therein, subject to its right to invoke the dispute resolution procedures set forth in Section XX.

3. If the Division concludes, based on the initial or any subsequent request by NPC for a determination that the Work has been performed in accordance with this AOC, the Division will so notify NPC in writing.

XVI. EMERGENCY RESPONSE

1. In the event of any action or occurrence during the performance of the Work, which causes or threatens a Release of Waste Material from the Site that constitutes an emergency situation or may present an imminent and substantial threat to human health or welfare or the Environment, NPC shall, subject to Paragraph 2 of this Section, immediately take all appropriate action to prevent, abate, or minimize such Release or threat of Release, and shall immediately notify the Division's Project Coordinator, or, if the Project Coordinator is unavailable, the Division's Alternate Project Coordinator. If neither of these persons is available, NPC shall notify the Chief of the Bureau of Corrective Action. In no case will this Paragraph relieve NPC from complying with State reporting requirements contained in NAC 445A.347 (such section titled "Notice Required") when any such reportable event occurs. NPC shall take such actions in consultation with the Division's Project Coordinator or other available authorized Division officer and in accordance with all applicable provisions of the health and safety plans, the contingency plans, and any other applicable plans or documents developed pursuant to the Scope of Work. In the event that NPC fails to take appropriate Response Action(s) as required by this Section, and the Division takes such action instead, NPC shall reimburse the Division all costs of the response action pursuant to Section XVII (such section titled "Reimbursement of Division Oversight Costs") and NPC will, if applicable, be subject to

the stipulated penalties set forth in Section XXI. In the event that the Division is required to take action pursuant to this Paragraph, NPC may not dispute the Division's actions under the dispute resolution provisions of this AOC prior to the Division taking such actions; however, NPC may later dispute only the Division's determination of imminent and substantial threat.

2. Nothing in the preceding Paragraph or in this AOC shall be deemed to limit any authority of the Division: (a) to take all appropriate action to protect human health and the Environment or to prevent, abate, respond to, or minimize an actual or threatened Release of Waste Material on, at, or from the Site or (b) to direct or order such action, or seek an order from the Court, to protect human health and the Environment or to prevent, abate, respond to, or minimize an actual or threatened release of Waste Material on, at, or from the Site, subject to Section XXIII (such section titled "Covenants by the Nevada Power Company and Reservation of Rights").

XVII. REIMBURSEMENT OF DIVISION OVERSIGHT COSTS

1. Following the Effective Date and for the Effective Period of this AOC, NPC shall reimburse the Division for costs reasonably incurred for oversight of this AOC. NPC shall advance the Division $100,000 within thirty (30) days after the Effective Date of this AOC. The Division shall draw upon the advance to pay its oversight costs and NPC shall remit to the Division payment on a quarterly basis the amount necessary to restore the advanced funds to $100,000 as described in Paragraphs 2 and 3. Such payments shall cover all reasonable direct and indirect costs incurred by the Division in overseeing, administering, or performing Work regarding NPC's implementation of the requirements of this AOC. Costs incurred may also include reasonable costs associated with conducting discussions regarding disputes that may arise under this AOC (except where the Division's actions are not upheld in the dispute resolution process). Reimbursable costs shall not include any direct or indirect costs incurred in connection with a matter subject to dispute resolution after the filing of a Statement of Position (as defined in Section XX below) by NPC. Reimbursable costs shall exclude the costs and expenses incurred by the Division's consultants and Contractors, which will be paid directly by NPC as described herein. The Division shall be responsible for selecting and managing the work performed by its consultants and Contractors, provided that such consultants and Contractors shall contract with NPC for the services to be provided under this

AOC, shall meet the contracting procedures customarily used by NPC, including those related to the content of invoices, and shall submit their invoices directly to NPC. The consultants and Contractors shall report directly to the Division and send a copy of all reports to NPC. NPC shall forward each invoice to the Division for review and approval and shall pay such invoice after approval of the Division.

2. The Division shall submit to NPC invoices for its oversight and expenses on a quarterly basis. Submittals shall be made promptly after the Division's preparation and internal review. Such invoices shall contain reasonable detail regarding the work performed. To the extent practicable, the Division will identify in reasonable detail the costs and expenses incurred for each task performed by the Division. Upon request, the Division shall make available to NPC all relevant documents in support of its invoices for inspection or audit by NPC.

3. All payments due by NPC hereunder shall be received by the Division within sixty (60) days of NPC's receipt of the invoice, shall reference the name of the Site, the Company name and address, the progress billing number identified in the Division invoice and shall be by a check payable to the "State of Nevada Hazardous Waste Fund" for the full amount due and owing to:

Nevada Division of Environmental Protection
901 South Stewart Street, Suite 4001
Carson City, Nevada 89701
Attn: Chief, Bureau of Corrective Actions

4. Upon termination of this AOC pursuant to Section XXXV, NPC shall receive the balance of any remaining funds advanced pursuant to this Section XVII.

5. NPC may contest payment of any Oversight Costs under this Section if it determines that the Division has made an accounting error or if it alleges that a cost item that is included represents costs that are unreasonable or inconsistent with the Work. Such objection shall be made in writing within thirty (30) days of receipt of the invoice and must be sent to the Division pursuant to Section XXV (such section titled "Notices and Submissions"). Any such objection shall specifically identify the contested Oversight Costs and the basis for objection. In the event of an objection, NPC shall within sixty (60) days pay all uncontested Oversight Costs to the State in the manner described in Paragraph 3 and NPC shall initiate the

dispute resolution procedures in Section XX. If the Division prevails in the dispute, within fifteen (15) days of the resolution of the dispute, NPC shall pay the sums due (with accrued Interest) to the Division in the manner described in Paragraph 3. If NPC prevails concerning any aspect of the contested costs, NPC shall pay that portion of the costs (plus associated accrued Interest) for which they did not prevail to the Division. The dispute resolution procedures set forth in this Paragraph in conjunction with the procedures set forth in Section XX shall be the exclusive mechanisms for resolving disputes regarding NPC's obligation to reimburse the Division for its Oversight Costs.

6. In the event that the payments required by this Section are not made within sixty (60) days of NPC's receipt of the invoice, NPC shall pay Interest on the unpaid balance. The Interest on Oversight Costs shall begin to accrue on the due date of the invoice. The Interest shall accrue through the date of NPC's payment. Payments of Interest made under this Paragraph shall be in addition to such other remedies or sanctions available to the Division by virtue of NPC's failure to make timely payments under this Section, including the assessment of stipulated penalties. NPC shall make all payments required by this Paragraph in the manner described in Paragraph 3.

XVIII. INDEMNIFICATION

1. The Nevada Power Company's Indemnification of the Division. The Division does not assume any liability by entering into this AOC. NPC shall indemnify, save and hold harmless the Division, and its officials, agents, employees, Contractors, subcontractors, or representatives for or from any and all claims or causes of action arising from, or on account of, negligent or other wrongful acts or omissions of NPC, its officers, directors, employees, agents, Contractors, subcontractors, and any persons acting on its behalf or under its control, in carrying out activities pursuant to this AOC. Further, NPC agrees to pay the Division all costs it incurs including, but not limited to, attorneys fees and other expenses of litigation and settlement arising from, or on account of, claims made against the Division based on negligent or other wrongful acts or omissions of NPC, its officers, directors, employees, agents, Contractors, subcontractors, and any persons acting on its behalf or under its control, in carrying out activities pursuant to this AOC. This indemnity shall not apply to any negligent or other wrongful acts or omissions of the Division, or any of its employees, agents, contractors,

subcontractors, and any persons acting on its behalf or under its control. The Division shall not be held out as a party to any contract entered into by or on behalf of NPC in carrying out activities pursuant to this AOC. Neither NPC nor any such Contractor shall be considered an agent of the State.

2. The Division shall give NPC notice of any claim for which the Division plans to seek indemnification pursuant to Paragraph 1 within sixty (60) days of service of a complaint, and shall not settle any such claims without written approval from NPC, which approval shall not be unreasonably withheld. The Division may tender the defense of such a claim to NPC.

3. NPC waives all claims against the Division for damages or reimbursement or for set-off of any payments made or to be made to the Division, arising from or on account of any contract, agreement, or arrangement between NPC and any person for performance of Work on or relating to the Site, including, but not limited to, claims on account of construction delays. In addition, NPC shall indemnify and hold harmless the Division with respect to any and all claims for damages or reimbursement arising from or on account of any contract, agreement, or arrangement between NPC and any person for performance of Work on or relating to the Site, including, but not limited to, claims on account of construction delays. This indemnity shall not apply to any negligent or other wrongful acts or omissions of the Division, or any of its employees, agents, Contractors, subcontractors and any persons acting on its behalf or under its control including without limitation any Contractors with whom NPC contracts under Section XVII, Paragraph 1.

XIX. FORCE MAJEURE

1. NPC shall perform the requirements of this AOC within the time limits prescribed, unless the performance is prevented or delayed by events that constitute a *force majeure*. NPC shall have the burden of proving such a *force majeure*. A *force majeure*, for purposes of this AOC, is defined as any event arising from causes not reasonably foreseeable or beyond the reasonable control of NPC, or of any person or entity controlled by NPC, which delays or prevents the timely performance of any obligation under this AOC despite NPC's best efforts to fulfill such obligation. A *force majeure* may include without limitation: extraordinary weather events, natural disasters, strikes and lockouts [by other than NPC employees], national emergencies, wars, acts of terror, delays in obtaining access or use of property not owned or

controlled by NPC despite timely best efforts to obtain such access or use approval, and delays in obtaining any required approval or permit from the Division or any other public agency that occur despite NPC's complete, timely and appropriate submission of all information and documentation required for approval or applications for permits within a timeframe that would allow the Work to proceed in a manner contemplated by the schedule of the AOC. A *force majeure* does not include (i) increased costs of the Work to be performed under the AOC, (ii) financial inability to complete the Work or (iii) normal weather events.

2. If any event occurs or has occurred that may delay the performance of NPC's obligations under this AOC, whether or not caused by a *force majeure* event, NPC shall notify the Division orally within three (3) Days of when NPC first knew that the event might cause a delay. If NPC wishes to claim a *force majeure* event, then within seven (7) Days thereafter, NPC shall provide to the Division a written explanation and description of the obligation(s) delayed or affected by the *force majeure* event; the reasons for the delay; the anticipated duration of the delay; a schedule for implementation of any measures to be taken to prevent or mitigate the delay or the effect of the delay; NPC's rationale for attributing such delay to a *force majeure* event; and a statement as to whether, in the opinion of NPC, such event may cause or contribute to an imminent and substantial hazard to human health, welfare, or the Environment. NPC shall include with any notice all available documentation supporting its claim that the delay was attributable to a *force majeure*. Failure to comply with the above requirements shall preclude NPC from asserting any claim of *force majeure* for that event.

3. The Division shall notify NPC in writing of its *force majeure* determination within ten (10) Days after receipt of the written notice from NPC. If the Division determines that the delay has been or will be caused by circumstances constituting a *force majeure* event, the time for performance of the obligations under this AOC that are affected by the *force majeure* event will be extended by the Division in writing for such time as the delay that was occasioned by that *force majeure* event. An extension of the time for performance of the obligations affected by the *force majeure* event shall not, of itself, extend the time for performance of any other obligation, unless NPC can demonstrate to the Division's satisfaction that more than one obligation was affected by the *force majeure* event.

4. In the event that the Division and NPC cannot agree that any delay or failure has

been or will be caused by circumstances constituting a *force majeure*, or if there is no agreement on the length of the extension, the dispute shall be resolved in accordance with the dispute resolution provisions set forth in Section XX ("Dispute Resolution") of this AOC.

XX. DISPUTE RESOLUTION

1. The Parties agree that the procedures contained in this Section are the sole and exclusive procedures for resolving disputes arising under this AOC. If NPC fails to follow any of the requirements contained in this Section, then they shall have waived its rights to further consideration of the dispute in issue.

2. If NPC disagrees with any determination by the Division pursuant to this AOC, for which NPC has reserved its right to dispute resolution, NPC shall notify the Division in writing of the dispute ("Notice of Dispute") within fifteen (15) Days.

3. Any dispute that arises under or with respect to this AOC shall in the first instance be the subject of informal negotiations between the Parties. The period for informal negotiations shall not exceed fifteen (15) Days following the date the dispute arises, unless such period is extended by written agreement of the Parties. The dispute shall be considered to have arisen when the Division receives a "Notice of Dispute."

4. In the event that the Parties cannot resolve a dispute by informal negotiations under the preceding Paragraph, then the position advanced by the Division shall be considered binding unless, within ten (10) Days after the conclusion of the informal negotiation period, NPC invokes the formal dispute resolution procedures of this Section by serving on the Division Administrator a written "Statement of Position" which shall set forth the specific points of the dispute, the position NPC claims should be adopted as consistent with the requirements of this AOC, the basis for NPC's position, any factual data, analysis or opinion supporting that position, any supporting documentation relied upon by NPC, and any matters which it considers necessary for the Administrator's determination. The "Statement of Position" also may include a request for an opportunity to make an oral presentation of factual data, supporting documentation and expert testimony to the Administrator and to answer questions that the Administrator may pose. It is within the sole discretion of the Administrator to grant or deny a request for an oral presentation.

5. Within fifteen (15) days following receipt of a Statement of Position, or after any

oral presentation by NPC, the Administrator shall issue his/her decision. The Administrator's written decision shall include a response to NPC's arguments and evidence. The written decision of the Administrator shall be incorporated into and become an enforceable element of this AOC, and shall be considered the Division's final decision as provided in Paragraph 6 of this Section.

6. As to any final Division decision, NPC may, as appropriate, pursue the dispute before the State Environmental Commission ("SEC") as a "contested case" pursuant to NRS §§ 233B.010 *et seq.* and NAC §§ 445B.875 – 445B.899, and shall be entitled to judicial review as provided therein.

XXI. STIPULATED PENALTIES

1. The Division may assess stipulated penalties in the amounts set forth in Paragraph 3 for failure to comply with the requirements of this AOC specified below, unless excused under Section XIX (such section titled "Force Majeure").

2. "Compliance" by NPC shall include completion of the activities under this AOC or any Work plan or other plan approved under this AOC identified below in accordance with all applicable requirements of law, this AOC, the Scope of Work, and any plans or other documents approved by the Division pursuant to this AOC and within the specified time schedules established by and approved under this AOC.

3. Stipulated Penalty Amounts - The following stipulated penalties shall accrue per violation per Day for any noncompliance identified:

Maximum Penalty Per Violation Per Day	Period of Noncompliance
$ 3,500.00	1st through14th Day
$ 5,500.00	15th through 30th Day
$11,000.00	31st Day and beyond

4. All penalties shall begin to accrue on the Day after the complete performance is due or the Day a violation occurs, and shall continue to accrue through the final Day of the correction of the noncompliance or completion of the activity. Nothing herein shall prevent the simultaneous accrual of separate penalties for separate violations of this AOC.

5. Following the Division's determination that NPC has failed to comply with a requirement of this AOC, the Division shall give NPC written notification of the same and

describe the noncompliance. If stipulated penalties are assessed, the Division shall send NPC a written demand for the payment of the penalties. Failure to pay Division Oversight Costs pursuant to Section XVII ("Reimbursement of Division Oversight Costs") can be included as a determination of failure to comply pursuant to this Section.

6. All penalties accruing under this Section shall be due and payable to the Division within sixty (60) Days of NPC's receipt from the Division of a demand for payment of the penalties, unless NPC invokes the dispute resolution procedures under Section XX. The amount of the stipulated penalty is not subject to appeal. NPC can only appeal the underlying violation or act of non-compliance forming the basis for the stipulated penalty, including but not limited to the Day a violation is alleged to have occurred and the Day when correction of the noncompliance was completed. All payments to the State under this Section shall be paid by certified or cashier's check(s) made payable and mailed as detailed in Section XVII (such section titled "Reimbursement of Division Oversight Costs") and shall indicate that the payment is for stipulated penalties, and shall reference the Division, the Site and the name and address of the Company making payment.

7. The payment of penalties shall not alter in any way NPC's obligation to complete the performance of the Work required under this AOC.

8. Except as provided in Paragraph 10 below, penalties assessed by the Division shall continue to accrue as provided in Paragraph 4 during any dispute resolution period, but need not be paid until the following:

a. If the dispute is resolved by agreement or by a decision of the Division that is not appealed to the Environmental Commission, accrued penalties determined to be owing shall be paid to the Division within sixty (60) Days of the agreement or the receipt of the Division's decision or order;

b. If the dispute is appealed to the Environmental Commission and the State prevails in whole or in part, NPC shall pay all accrued penalties determined to be owed to the Division within sixty (60) Days of receipt of the decision or order, except as provided in Subparagraph c below;

c. If the Environmental Commission's decision is appealed by any Party, NPC shall pay all accrued penalties determined to be owing to the State into an interest-

bearing escrow account within sixty (60) Days of receipt of the Commission's decision or order. Penalties shall be paid into this account as they continue to accrue, at least every sixty (60) Days. Within sixty (60) Days of receipt of the final District court decision, the escrow agent shall pay the balance of the account to the Division or to NPC to the extent that they prevail.

9. Stipulated penalties shall not accrue with respect to a decision by the Administrator under Paragraph 3 of Section XX ("Dispute Resolution"), during the period, if any, beginning on the 16th Day after the receipt of a Statement of Position by the Administrator until the date that the Administrator issues a decision.

10. If NPC fails to pay stipulated penalties when due, the State may institute proceedings to collect the penalties, as well as Interest. NPC shall pay Interest on the unpaid balance, which shall begin to accrue on the date of demand made pursuant to Paragraph 6.

11. If the Division chooses to assess stipulated penalties for a violation by NPC, such assessment shall be the exclusive remedy of the Division with respect to the payment of penalties.

12. Notwithstanding any other provision of this Section, the Division may, in its unreviewable discretion, waive any portion of stipulated penalties that have accrued pursuant to this AOC.

XXII. COVENANTS BY THE DIVISION AND RESERVATION OF RIGHTS

1. Covenants Not to Sue. In consideration of the actions that will be performed and the payments that will be made by NPC under the terms of the AOC, and except as specifically provided in Paragraph 5 of this Section, the Division covenants not to sue or to take administrative action against the Company pursuant to Environmental Laws, including but not limited to, Nevada State Law, CERCLA § 107(a), the Resource Conservation and Recovery Act, 42 U.S.C. §§ 6901 6992k, or the Clean Water Act, 33 U.S.C. §§ 1251-1387 for matters addressed by this AOC. These covenants not to sue shall take effect upon the receipt by the Division of the payments required by Paragraph 3 of Section XVII (such section titled "Reimbursement of Division Oversight Costs"). These covenants not to sue are conditioned upon the satisfactory performance by NPC of its obligations under this AOC.

2. The Division's Pre-Determination of Completion Reservations. Notwithstanding any other provision of this AOC, the Division reserves, and this AOC is without prejudice to,

the right to institute civil or administrative proceedings, or to issue an administrative order seeking to compel NPC:

a. to perform further Response Actions relating to the Site for matters not the subject of Work approved by the Division and being performed by NPC; or

b. to reimburse the Division for additional costs of response; if prior to determination of completion of the Work under Section XV:

(1) conditions at the Site, previously unknown to the Division, are discovered, or

(2) information, previously unknown to the Division, is received, in whole or in part, and these previously unknown conditions or information together with any other relevant information indicates that the Corrective Action (s) are not protective of human health or the Environment.

3. The Division's Post-Determination of Completion Reservations. Notwithstanding any other provision of this AOC, the Division reserves, and this AOC is without prejudice to, the right to institute civil or administrative proceedings, or to issue an administrative order seeking to compel NPC:

a. to perform further Response Actions relating to the Site; or

b. to reimburse the Division for additional costs of response; if subsequent to determination of completion of the Work under Section XV:

(1) conditions at the Site, previously unknown to the Division, are discovered, or

(2) information, previously unknown to the Division, is received, in whole or in part, and these previously unknown conditions or this information together with other relevant information indicate that the Remedy(ies) is/are not protective of human health or the Environment.

4. For purposes of Paragraph 2, the information and the conditions known to the Division shall include only that information and those conditions known to the Division as of the date the appropriate Work plans are approved. For purposes of Paragraph 3, the information and the conditions known to the Division shall include only that information and those conditions known to the Division as of the date of determination of completion of the Work as

set forth in a "No Further Action" letter, the administrative record supporting the determination of "No Further Action", or the post-"No Further Action" administrative record.

5. General Reservations of Rights. The covenants not to sue set forth above do not pertain to any matters other than those expressly specified in Paragraph 1 of this Section. The Division reserves, and this AOC is without prejudice to, all rights against NPC with respect to all other matters, including but not limited to, the following:

a. claims based on a failure by NPC to meet a requirement of this AOC;

b. liability arising from the past, present, or future disposal, Release, or threat of Release of Waste Materials outside of the Site;

c. liability for future disposal of Waste Material at the Site, other than as provided in the Work or otherwise ordered by the Division;

d. liability for damages for injury to, destruction of, or loss of natural resources, and for the costs of any natural resource damage assessments;

e. criminal liability;

f. liability for violations of federal or state law which occur during or after implementation of the Corrective Action; and

g. liability, prior to issuance of a NFA letter, for additional response actions that the Division determines are necessary to achieve Corrective Action Standards, but that cannot be required pursuant to Section XXIX (such section titled "Modification"), Paragraph 4.

6. The Division reserves all of its statutory and regulatory powers, authorities, rights, and remedies, both legal and equitable, which may pertain to NPC's failure to comply with any of the requirements of this AOC or of any requirement of federal or state laws, regulations, or permit conditions. Except as otherwise provided in this Section, this AOC shall not be construed as a covenant not to sue, release, waiver, or limitation of any rights, remedies, powers, and/or authorities, civil or criminal, which the Division has under any applicable Environmental Law or common law authority of the State. This AOC in no way relieves NPC of its responsibility to comply with any federal, State or local law or regulation.

7. The Division reserves the right to disapprove Work performed by NPC pursuant to this AOC subject to the dispute resolution provisions in Section XX.

8. The Division reserves any and all legal rights and equitable remedies available to

enforce (1) the provisions of this AOC, or (2) any applicable provision of State or federal law.

9. If the Division determines that activities in compliance or noncompliance with this AOC have caused a Release of Environmental Contaminant that may present an imminent and substantial hazard to human health, welfare, and/or the Environment, the Division may order NPC to stop further implementation of this AOC for such period of time as the Division determines may be needed to abate any such Release and/or to undertake any action which the Division determines is necessary to abate such Release.

10. This AOC is neither a permit nor a modification of a permit. NPC acknowledges and agrees that the Division's approval of any Work plan hereunder does not constitute a warranty or representation that the Work plan will achieve the required or appropriate Corrective Action Standards.

11. Notwithstanding any other provision of this AOC, except as provided in Section XX, no action or decision by the Division pursuant to this AOC including without limitation, decisions by the Administrator, shall constitute final agency action giving rise to any right of judicial review prior to the Division's initiation of a judicial action to enforce this AOC, including an action to collect penalties or an action to compel NPC's compliance with the terms and conditions of this AOC.

12. In any subsequent administrative or judicial proceeding initiated by the State for injunctive or other appropriate relief relating to the Site, NPC shall not assert, and may not maintain, any defense or claims based upon the principles of waiver, claim-splitting, or other defenses based upon any contention that the claims raised by the State of Nevada in the subsequent proceeding were or should have been raised in this AOC, except as to claims based on information known to the Division as of the Effective Date that relate to the subject matter of this AOC.

13. Work Takeover. In the event the Division determines that NPC has ceased implementation of any required portion of the Work, are seriously or repeatedly deficient or late in its performance of the Work, or are implementing the Work in a manner, which may cause an endangerment to human health or the Environment, the Division may assume the performance of all or any portions of the Work as the Division determines necessary. Costs incurred by the State in performing the Work pursuant to this Paragraph shall be considered

Oversight Costs that NPC shall pay pursuant to Section XVII (such section titled "Reimbursement of Division Oversight Costs") and NPC will be subject to the stipulated penalties set forth in Section XXI.

14. Notwithstanding any other provision of this AOC, the Division retains all authority and reserves all rights to take any and all response actions authorized by law.

XXIII. COVENANTS BY THE NEVADA POWER COMPANY AND RESERVATION OF RIGHTS

1. Covenant Not to Sue. Subject to the reservations in Paragraph 2, NPC hereby covenants not to sue and agrees not to assert any claims or causes of action against the State with respect to the Site, for past Response Actions, and Oversight Costs as defined herein, or this AOC, including, but not limited to:

a. any direct or indirect claim for reimbursement; or

b. any claims arising out of response activities at the Site, including claims based on the Division's selection of Response Actions, oversight of response activities or approval of plans for such activities.

2. NPC reserves, and this AOC is without prejudice to, claims against the State of Nevada, subject to the limitations of NRS Chapter 41, for money damages for injury or loss of property or personal injury or death caused by the negligent or wrongful act or omission of any employee of the State, relating to implementation of this AOC, while acting within the scope of his office or employment. However, any such claim shall not include a claim based on the Division's selection of Response Actions, or the oversight or approval of NPC's plans or activities. To the extent permitted by law, the Division shall indemnify, hold harmless, and defend, not excluding NPC's right to participate, NPC, its officers, agents, employees, Contractors, subcontractors and representatives for, from and against any and all claims, causes of action, costs and expenses (including but not limited to reasonable attorneys' fees and costs), arising out of the alleged negligent or willful acts or omissions of the Division or its employees, agents and Contractors in implementing this AOC.

3. General Reservations of Rights. NPC reserves all rights, claims and/or defenses they may have in any action brought or taken by or against the Division, the EPA or any third party pursuant to applicable law, with respect to the specific claims that can be asserted at the Site.

4. Nothing in this agreement shall be construed as an admission of liability by NPC.

XXIV. CONFIDENTIAL BUSINESS INFORMATION

1. All information required by this AOC will be deemed public information upon submittal to the Division unless NPC requests in writing at the time of submittal that specific information be treated as confidential, business information in accordance with NRS §§ 459.555 or 445A.665, and such regulations adopted there under, and the Division grants the request. Pending such determination and any appeals thereof, the Division shall treat such information as confidential. NPC shall adequately substantiate any assertion of confidentiality in writing when the request is made. NPC may assert business confidentiality claims covering part or all of the documents or information submitted to the Division under this AOC to the extent permitted. If no claim of confidentiality accompanies a document or information when it is submitted to the Division, or if the Division has notified NPC that the document or information is not confidential, the public may be given access to such documents or information without further notice to NPC.

2. No documents, reports or other information created or generated or submitted pursuant to the requirements of the AOC shall be withheld on the grounds that they are privileged.

3. No claim of confidentiality shall be made with respect to any data including, but not limited to, all sampling, analytical, monitoring, hydrogeologic, scientific, chemical, or engineering data or any other documents or information evidencing conditions at or around the Site.

XXV. NOTICES AND DELIVERABLES

1. Whenever, under the terms of this AOC, written notice is required to be given or a report, Deliverable or other document is required to be sent by one Party to another, it shall be directed to the individuals at the addresses specified below, unless those individuals or its successors give notice of a change of individual or address to the other Party in writing. All notices and Deliverables shall be considered effective upon receipt, unless otherwise provided. Written notice as specified herein shall constitute complete satisfaction of any written notice requirement of the AOC with respect to the Division and NPC, respectively.

As to the State: Nevada Division of Environmental Protection
2030 E Flamingo Road, Suite 230

Las Vegas, NV 89119
Attn: Project Coordinator (Nevada Power)

Remediation Branch Supervisor
Nevada Division of Environmental Protection
2030 E Flamingo Road, Suite 230
Las Vegas, NV 89119
Attn: Alternate Project Coordinator (Nevada Power)

As to NPC:

Nevada Power Company
Reid Gardner Generating Station
P.O. Box 279
501 Wally Kay Way
Moapa, NV 89025
Attn: Supervisor, Environmental Services, MS #77

Nevada Power Company
6226 West Sahara Avenue
Las Vegas, NV 89146
Attn: Manager, Environmental Services, Coal Generation, MS #30

XXVI. COOPERATION IN REVIEW

1. With respect to any action by NPC or the Division contemplated by this AOC (including without limitation the provisions of Section VII (such section titled "Performance of the Work by the Nevada Power Company") for which a time period is not specified herein or in any relevant Work plan, NPC and the Division agree to perform such actions within a reasonable time under the circumstances, so as to not prejudice the other party.

XXVII. INCORPORATION AND ENFORCEABILITY OF APPENDICES OR REFERENCED MATERIALS

1. Any and all AOC amendment(s) or modification(s), Work plan(s) (including each schedule contained therein and attachments thereto), and Deliverable(s) required hereunder shall, upon execution or Division approval as submitted or developed by the Division, be deemed incorporated into and made fully enforceable under this AOC as if fully set forth herein. It is contemplated that from time to time, additional documents shall be executed or approved by the Division and shall, as such, be incorporated herein. The following appendices are incorporated into, and made fully enforceable under this AOC as if fully set forth herein:

a. "Appendix A" is the description of the Site subject to this AOC, and

b. "Appendix B" is the Scope of Work.

XXVIII. COMMUNITY RELATIONS

1. Subject to the provisions of Section XXIV ("Confidential Business Information"), all Deliverables received by the Division may be made available to the public in accordance with applicable law. The Division may, at its discretion, conduct a public notice or comment procedure with respect to any Deliverable submitted pursuant to this AOC. The Division shall notify NPC in writing of its determination to provide for, or legal requirement governing, public notice or comment with respect to such document as well as the corresponding adjustment that shall be made to any affected Work or Deliverable submittal or approved schedule. Following any such notice and comment period, the Division may require NPC to revise the Deliverable and/or perform reasonable additional Work necessary to address appropriately any issue regarding such document identified by the public during such comment period.

2. Within one hundred twenty (120) Days of the Effective Date, NPC shall submit and/or update a Community Relations Plan for the dissemination of information to the interested public regarding the activities to be conducted pursuant to this AOC. Any such plan shall, at a minimum, address the following:

a. provide for the periodic development and distribution of fact sheets summarizing current and/or proposed activities;

b. provide for the development of a mailing list for distribution of the fact sheets;

c. Identify a community liaison for NPC with respect to activities to be conducted pursuant to the AOC.

XXIX. MODIFICATION

1. This AOC may be modified or amended only upon the mutual agreement of NPC and the Division. Any agreed upon amendment or modification shall be in writing, shall be signed by all Parties, shall have as its Effective Date the date on which it is signed by the Division as the last Party executing the amendment or modification, and shall, upon that date, be incorporated into and made enforceable under this AOC.

2. Any requests for a compliance date modification or revision of an approved Deliverable requirement must be made in writing. Such requests must be timely and provide justification for any proposed compliance date modification or Deliverable revision. The

Division has no obligation to approve such requests, but if it does so, such approval must be in writing. Any approved compliance date or Deliverable modification shall be incorporated by reference into and made enforceable under this AOC.

3. No informal advice, guidance, suggestions, or comments by the Division regarding any matter associated with this AOC shall be construed as relieving NPC of its obligation to obtain written approval regarding any Deliverable, if and when required by this AOC provided; however, that the Division shall consider the good faith reliance by NPC on such advice in the exercise of its prosecutorial discretion.

4. No material modifications shall be made to the Scope of Work without written notification to and written approval of the Division and NPC.

5. othing in this Agreement shall be deemed to alter the State's authority to enforce, supervise, or approve modifications to this AOC.

XXX. COMPUTATION OF TIME

1. For purposes of computing due dates set forth in this AOC, the Effective Date or the Day of the act, event, or default from which the designated period of time begins to run, shall be designated and counted as Day zero (0). Calendar Days shall be utilized in computing due dates. The last Day of the period so computed shall be included, unless it is a Saturday, Sunday, or State or federal holiday, in which event the period runs until the end of the next Day which is not one of the aforementioned Days.

XXXI. GOVERNING LAW

1. The provisions and interpretation of this AOC shall be governed by the law of the State of Nevada without regard to choice of law statutes thereof. This agreement shall be interpreted to effectuate the intent and purpose of all relevant Environmental Laws.

XXXII. OTHER APPLICABLE LAWS

1. All actions required to be taken pursuant to this AOC shall be undertaken in accordance with the requirements of all applicable local, State, and federal laws and regulations. NPC shall obtain or cause its representative(s) to obtain all permits and approvals necessary under such laws and regulations.

XXXIII. SEVERABILITY

1. If any provision or authority of this AOC or the application of this AOC to any Party or

circumstances is held by any judicial or administrative authority to be invalid, and such holding does not result in a material change in the rights or obligations of the Parties, the application of such provisions to the other Party or circumstances and the remainder of the AOC shall remain in force and shall not be affected thereby.

XXXIV. EFFECTIVE DATE

1. This AOC shall become effective on the date upon which it is executed by the Division as the last Party executing this AOC, after it having previously been signed by NPC ("Effective Date"). This AOC may be executed in separate counterparts.

XXXV. TERMINATION

1. After completion of the obligations created by this AOC, including but not limited to the Work, NPC shall submit to the Division a Statement of Completion, as discussed in Section XV (such section titled "Determination of Completion") Part C (such part titled "Completion of the Work") which certifies that NPC has fulfilled all obligations under this AOC, including the performance of any additional Work and the payment of any costs and stipulated penalties to the Division. Within a reasonable time after receipt of the Statement of Completion, not to exceed one hundred-eighty (180) Days, the Division shall issue a written notice to NPC that either: (a) all obligations under this AOC have been fulfilled, or (b) all obligations have not been fulfilled. Such notice shall specify the obligations the Division believes must be fulfilled in order to satisfy this AOC. Except for the confidential business information obligations in Section XXIV of this AOC, any and all obligations of NPC created by the terms of this AOC shall be deemed satisfied and shall terminate upon issuance by the Division of written notice that NPC has fulfilled all obligations under this AOC.

XXXVI. MERGER

1. This AOC is the complete agreement between the Division and NPC. This AOC is the result of negotiations between the Parties over each provision contained herein. Each provision shall therefore be construed to have been mutually drafted and neither of the Parties shall be deemed to have solely drafted this entire AOC or any single provision herein.

XXXVII. SIGNATORIES/SERVICE

1. Each undersigned representative to this AOC certifies that he or she is fully authorized by the Party whom he or she represents to enter into the terms and conditions of

this AOC and to execute and legally bind such Party to this document. Additionally, NPC states that, under the Participation Agreement between CDWR and NPC, NPC has authority—as Operating Agent of Unit No. 4—to enter into this AOC with respect to Unit No. 4.

[signatures on the following page]

IN WITNESS WHEREOF, The Parties execute this AOC by their duly authorized representatives as of the date set forth above.

It is so agreed and ordered.

THE STATE OF NEVADA:

By: _____ Date: 2/20/08

Leo M. Drozdoff, P.E.

Administrator

For the State of Nevada, by and through its Department of Conservation & Natural Resources, Division of Environmental Protection

Approved as to form:

By: _____ Date: 2.22.08

William Frey

Senior Deputy Attorney General

State of Nevada

NEVADA POWER COMPANY:

By: _____ Date: 4/21/08

Name: Michael W. Yackira

Title: CEO

For NPC as the owner and operator of RGS Units No. 1, 2, and 3 and as Operating Agent of RGS Unit No. 4

Appendix "A"

Site Description

The Site consists of all that certain land, structures, other appurtenances, and improvements comprising NPC's Reid Gardner Station (RGS) as shown in Figure 1, located at 501 Wally Kay Way, Moapa, NV in Section 05, Township 15 South, Range 66 East, together with adjacent private and public properties, including the Muddy River, that have been impacted by the Release of Environmental Contaminants from RGS as shown by characterization results and/or Corrective Action activities carried out under this AOC. Figure 1 illustrates the initial boundaries of the Site as the property boundary of the RGS plus those portions of Areas 1 – 7 lying outside of the RGS property boundary.

Appendix "B"

Scope of Work

ND: 4811-3478-1186, Ver 1

APPENDIX B

ADMINISTRATIVE ORDER ON CONSENT

Reid Gardner Station

Scope of Work

1.0 Introduction

The Administrative Order on Consent (AOC) to which this Scope of Work (Scope) is attached and incorporated therein provides for the continuation of Environmental Contaminant characterization activities, allows for the identification and/or screening of Corrective Actions, and allows for the implementation and long-term Operation and Maintenance of Division-approved Corrective Actions at or associated with Reid Gardner Station (Site).

2.0 Objectives for the Scope of Work

The overall objective for the Scope is to provide a framework for the completion of characterization activities for groundwater and soil within the Site boundaries and for the identification and implementation of Corrective Actions applicable to each media as necessary. The common objective of all parties is to seek permanent Remedies for all media that address current and future risks to human health and the Environment.

2.1 Deliverables and Division Decision Documents

This Scope defines specific Deliverables and Division decision documents that provide a framework and sequence for activities to be completed. The list of these documents is described in Section 3.0. It should be noted that this Scope cannot anticipate every scenario that may unfold during the course of investigation, characterization, and remediation of the Site. Additional Deliverables may be required to complete the project. Similarly, some of the Work products may be combined or eliminated at the discretion of the Division as the project progresses.

Detailed Work Plans are required for submittal to the Division for review and approval prior to the start of any field or study activities. It is expected that technical issues will be discussed and resolved in meetings prior to formal document submittal.

2.2 Definitions

Any capitalized term used in this Scope that is defined in Section 2.0 of the AOC shall have the meaning assigned to the term in the AOC. Any other capitalized term shall have the meaning assigned to the term in the Scope.

APPENDIX B

3.0 Work To Be Performed

3.1 Deliverables to be Prepared by NPC

3.1.1 Encyclopedia of Supporting Documentation

This encyclopedia will be a list of the titles and locations of supporting documents that pertain to all projects and sub-areas with the Site. Examples include: Health and Safety Plan (as described in 3.1.4); Dust Mitigation Work Plan; Perimeter Air Monitoring Plan; Field Standard Operating Procedures (SOPs); Field Screening Methods and Equipment; Quality Assurance Project Plan (QAPP); the Document Numbering and Tracking System (see also Section 3.1.2); and field logs.

3.1.2 Document and Response to Comments Tracking System

The Division may provide NPC comments to draft submittals. Formal response-to-comments letters are required to such comments. The response to comments letters shall clearly address each comment and state where the comment has been addressed in the re-submittal. In addition, NPC is required to document a process to track and address the Division's historic comments concerning the Site. Through this mechanism, the Division is hereby incorporating the historic comments and the requirement for NPC to respond to these comments as part of this AOC. This Deliverable must be submitted and obtain Division approval prior to proceeding with document submittal.

3.1.3 Closure Plan

The Closure Plan is a "road map" that describes the process by which the Site and/or specific sub-areas of the Site will be closed. The Closure Plan should identify applicable or relevant and appropriate requirements (ARARs) for all applicable media at the Site. In addition, the Closure Plan includes the risk assessment Work Plan. This Deliverable must obtain Division approval.

3.1.4 Health and Safety Plan (HASP)

The HASP shall conform to applicable federal and state Occupational Safety and Health Administration requirements including, but not limited to, 29 CFR § 1910.120 and NRS Chapter 618. The Division's review will not constitute approval of the plan. However, this work is being conducted within the boundaries of a site for which the Division has jurisdiction; therefore, the Division reserves the right to review the general content of the HASP and may have comments to be considered by NPC. This Deliverable must be completed prior to the implementation of field activities conducted under this AOC. This Deliverable does not need to obtain Division approval.

APPENDIX B

3.1.5 Progress Reports

These reports shall be submitted in accordance with Section XII (Reporting Requirements), Paragraphs 1 and 2 of this AOC. These Deliverables must obtain Division approval.

3.1.6 Assessment of Background Conditions

The assessment of background conditions may be submitted through a series of Work plans and reports. Background conditions may be developed for various soils and water-bearing zones. All Work plans and reports regarding background conditions must obtain Division approval prior to implementation.

3.1.7 Site-Related Chemicals (SRC) Document

The SRC document is a description of all of the chemicals (including degradation by products) that are known to likely to exist in soils and groundwater at the Site based on available information. This Deliverable must obtain Division approval prior to submittal of the Site-Wide Conceptual Site Model.

3.1.8 Site-Wide Conceptual Site Model (CSM)

The site-wide CSM is a comprehensive description of the conditions at the Site. This report may result in the generation of other Work plans to address data gaps identified in the CSM. At a minimum, the CSM must include the following:

a. Comprehensive list of Site-related chemicals and/or surrogate indicator chemicals with proposed analytical methods (under separate cover as described above in Section 3.1.7),

b. Evaluation of background conditions (as described above in Section 3.1.6),

c. Delineation of known or potential source areas,

d. Presentation of the three dimensional nature and extent of contamination including on-Site and off-Site soils contamination, vadose zone contamination, groundwater contamination, surface water, and air.

e. Detailed evaluation of hydrogeological conditions including: cross-sections; evaluation of the interconnectivity of water-bearing zones; descriptions and illustrations regarding the thickness of saturated zones; and other descriptions and/or illustrations that fully describe the hydrogeological conditions of the Site, and

f. Steps 1 and 2 of the USEPA DQO process for site-wide DQOs, which must be submitted and obtain Division approval prior to submittal of specific sub-area Work plans.

g. Historical growth and/or retreat of the groundwater plume.

APPENDIX B

h. Parameters controlling contaminant fate and transport (e.g. groundwater velocity).

i. Designation of sub-areas.

j. Identification of data gaps.

k. Known or potential routes of migration.

l. Known or potential human and ecological receptors.

This Deliverable must obtain Division approval prior to submittal of the Groundwater Corrective Action Alternative Study.

3.1.9 Sub-Area Specific Work

As requested by the Division, the Site will be delineated into sub-areas with adequate justification for each delineation. For each sub-area, a number of documents may be required depending on the circumstances of each sub-area and may require Division approval prior to implementation. Examples of documents that may need to be produced for Division approval include Data Usability Assessment, sub-area CSM, sub-area DQOs (steps 3-7, as necessary), baseline risk determination report, data quality assessment, sub-area Corrective Action Plan, implementation of Corrective Action(s), data validation, and risk assessment (human health and ecological), etc.

3.1.10 Data Validation Reports

Data validation reports will need to be generated for data that are proposed to be used at the Site. It is recommended that these reports be submitted on specific data sets and not on the entire database in one report. These Deliverables must obtain Division approval.

3.1.11 Groundwater Modeling

Groundwater, air, and soil to groundwater leaching modeling may need to be completed as part of the evaluation of fate and transport mechanisms on the Site. The specific models and scenarios to be evaluated are currently under discussion but remain indefinite at this time. A Work Plan and a report must obtain Division approval for each instance and the models will be refined as additional data is collected. The types of modeling to be conducted will be negotiated with the Division as necessary. Modeling may be implemented to supplement the information in the CSM or may be implemented to satisfy data gaps identified in the CSM.

3.1.12 Corrective Action Alternative Study (CAAS)

Following characterization of the Site conditions, NPC must complete a CAAS for groundwater at the Site. Corrective Action alternatives should be evaluated using appropriate feasibility studies. Site characterization activities that remain should be fully

integrated with the development and evaluation of alternatives in the feasibility study. This Deliverable must obtain Division approval prior to submittal of a Corrective Action Plan. (Note: more than one Corrective Action Plan may be submitted for the Site on a sub-area basis.)

3.1.13 Corrective Action Plan (CAP)

This Deliverable shall describe methods, procedures, and activities by which NPC will implement the Division-approved Corrective Action(s). Additionally, this document must obtain Division approval prior to Implementation of the CAP. (Note: more than one Corrective Action Plan may be submitted for the Site on a sub-area basis.)

3.1.14 Implementation of CAP

Once the CAAS has been developed and the Division approves a CAP, several Work plans and reports will be generated to detail the implementation of the Division-approved Corrective Action(s). Once approved by the Division, the CAP must be implemented according to the schedule. (Note: more than one Corrective Action Plan may be submitted for the Site on a sub-area basis.)

3.1.15 CAP Completion Document

This Deliverable shall be submitted when NPC determines that the Corrective Action(s) implemented for the Site (or a specific sub-area of the Site) has been completed in accordance with Section XV (Determination of Completion), Paragraph C (Completion of Work) of this AOC or is no longer efficient. The CAP Completion Document should recommend either closure of the Site (or specific sub-area of the Site) or the submittal of a revised CAAS for the Site (or specific sub-area of the Site). The CAP Completion Document shall include technical discussion, analytical data, and risk assessment for the presented recommendation. This Deliverable must obtain Division approval.

3.2 Approval Documents to be Prepared by the Division

3.2.1 Comments Tracking System Approval

3.2.2 Closure Plan Approval

3.2.3 Progress Report Approval

3.2.4 Assessment of Background Conditions Work Plan(s) and Report Approval

3.2.5 SRC Approval

3.2.6 CSM Approval

APPENDIX B

3.2.7 Sub-area Specific Work Plan(s) and other sub-area Work Approval

3.2.8 DVSR Approval

3.2.9 Groundwater Modeling Deliverable Approval

3.2.10 CAAS Approval

3.2.11 CAP Approval

3.2.12 CAP Completion Document Approval

4.0 Schedule for Scope Implementation and Deliverables

The Implementation of the Scope shall begin upon the Effective Date of the AOC. Pursuant to the AOC, NPC agree to perform the work included in this Scope by the milestones specified herein, within the AOC or within an approved Deliverable. All dates calculated herein shall be in accordance with the Computation of Time section of the AOC.

EXHIBIT JOHNS-DIRECT-4

ENVIRONMENTAL AGREEMENT

between

NEVADA POWER COMPANY

and

CALIFORNIA DEPARTMENT OF WATER RESOURCES

Dated: July 18, 2013

ENVIRONMENTAL AGREEMENT

This **ENVIRONMENTAL AGREEMENT** ("this Agreement") dated as of July 18, 2013 ("Execution Date"), is between **NEVADA POWER COMPANY**, a Nevada corporation, doing business as NV Energy ("NVE"); and **CALIFORNIA DEPARTMENT OF WATER RESOURCES**, an agency of the State of California ("CDWR"). CDWR and NVE are at times referred to collectively as the "Parties" and individually as a "Party."

RECITALS:

A. The Parties entered into that certain Reid Gardner Unit No. 4 Participation Agreement, dated July 11, 1979, as supplemented by various Memoranda of Agreement (collectively, the "Participation Agreement"), pursuant to which unit number 4 ("Unit 4") at the Reid Gardner Generating Station (the "Station") as more particularly described in the Participation Agreement was constructed, operated, and maintained.

B. The Participation Agreement provides for the operation and joint ownership of Unit 4. In addition, the Participation Agreement provides for the ownership and allocation of the electric power produced from the operation of Unit 4.

C. NVE is, and has always been, the owner and operator of Units 1, 2, and 3 of the Station.

D. After evaluation by the Nevada Department of Conservation and Natural Resources, Division of Environmental Protection (the "Division") of the environmental conditions at the Station, the Division and NVE executed the Administrative Order on Consent, dated February 20, 2008 ("AOC"), a copy of which is attached hereto as Exhibit B.

E. NVE has taken, and will continue to take, a number of actions to address the Pollution Conditions at and around the Station.

F. The Participation Agreement identifies July 25, 2013, as the date upon which the Participation Agreement is scheduled to terminate ("Termination Date"). The Parties entered into a Termination Settlement Agreement, dated March 11, 2013 ("Termination Settlement Agreement"), to more completely address the details related to the termination of the Participation Agreement. The Termination Settlement Agreement specifically does not address the environmental and other obligations addressed in this Agreement. The Closing of the Termination Settlement Agreement is a condition precedent to this Agreement becoming effective. Execution of this Agreement is a condition precedent to Closing under the Termination Settlement Agreement.

G. NVE has incurred costs to comply with the AOC and it will continue to incur costs following the Termination Date.

H. After having engaged in negotiations to develop an appropriate, scientifically-based cost allocation related to the AOC, the Parties have reached agreement on the allocation for such costs and now desire to enter into this Agreement.

NOW, THEREFORE, for and in consideration of the promises and of the mutual covenants and agreements contained in this Agreement,

IT IS HEREBY AGREED AS FOLLOWS:

1 DEFINITIONS

1.1 "Annual True-Up" shall have the meaning set forth in Section 5.9.

1.2 "Amendment Request" shall have the meaning set forth in Section 2.3.1.

1.3 "AOC" shall have the meaning set forth in Recital D.

1.4 "Budget Year" shall have the meaning set forth in Section 5.1.

1.5 "Business Day" means a day other than a Saturday, Sunday, or other day on which commercial banks in Sacramento, California, or Las Vegas, Nevada, are generally closed for business.

1.6 "CDWR Advance Payment" shall have the meaning set forth in Section 5.6.

1.7 "CDWR 2013 Environmental Costs" shall have the meaning set forth in Section 3.2.2.

1.8 "CDWR Past Environmental Costs" shall have the meaning set forth in Section 3.2.1.

1.9 "CDWR RG4 Company Allocation" shall have the meaning set forth in Section 2.1.3.

1.10 "Closing" shall have the same meaning as in the Termination Settlement Agreement.

1.11 "Commercially Reasonable Efforts" means the efforts that a prudent business Person would use in similar circumstances to achieve a desired result in a commercially reasonable manner and as expeditiously as possible; provided that an obligation to use such efforts under this Agreement does not require the Party subject to that obligation to take actions that would result in a material adverse change in the benefits to such Party of this Agreement.

1.12 "Cost Allocation Area(s)" means those areas identified as a Cost Allocation Area on Exhibit A, as it may be revised to reflect any addition or deletion of a Cost Allocation Area as provided for under this Agreement.

1.13 "Division" shall have the meaning set forth in Recital D.

1.14 "Disputed Advance Payment Amount" shall have the meaning set forth in Section 5.6.

1.15 "Disputed Budget Items" shall have the meaning set forth in Section 5.2.

1.16 "EA Assurance Escrow" shall have the meaning set forth in Section 6.1.1.

1.17 "E.A. Assurance Escrow Instructions" shall have the meaning set forth in Section 6.1.1.

1.18 "EA Budget" shall have the meaning set forth in Section 5.1.

1.19 "EA Payment Escrow" shall have the meaning set forth in Section 3.1.

1.20 "EA Payment Escrow Instructions" shall have the meaning set forth in Section 3.1.

1.21 "EA Manager" shall have the meaning set forth in Section 7.3.1.

1.22 "Environmental Action(s)" means any action taken after February 20, 2008 or planned to be taken by NVE, subject to the concurrence of the Division, that is related to the project requirements and/or liabilities associated with the AOC, including the investigation, testing and administrative functions necessary and appropriate under the AOC and this Agreement, and all actions taken after February 20, 2008 to characterize, monitor and remediate the Pollution Conditions. An Environmental Action also shall include the negotiation and communication with the Division related to the AOC.

1.23 "Environmental Contaminant" shall have the meaning set forth in the AOC.

1.24 "Environmental Cost(s)" means the reasonable funds necessary to perform any Environmental Action, including those actual costs incurred or accrued by NVE for reasonable and necessary internal administration and labor (e.g., time billed to and costs incurred in administering the AOC), internal services provided by NVE (e.g., fees or costs related to use of existing NVE-owned facilities), the construction and operation of necessary facilities, and reasonable and necessary third party services, costs, supplies, and equipment; provided, however, that such costs shall not include any borrowing or other financing costs incurred by NVE, including interest. Environmental Costs for any given Cost Allocation Area may include costs associated with soils, solids, and/or groundwater except as specifically noted on Exhibit A. An Environmental Cost does not include costs or expenses incurred by either Party to communicate or coordinate with the other Party relating to the AOC or to this Agreement or costs incurred by NVE to prepare any submittals to the Public Utilities Commission of Nevada.

1.25 "Execution Date" shall have the meaning set forth in the Preamble to this Agreement and shall be the date when the Parties are deemed to have executed this Agreement.

1.26 "Final EA Budget" shall have the meaning set forth in Section 5.5.

1.27 "Future Environmental Costs" means all Environmental Costs incurred after December 31, 2013.

1.28 "Governmental Authority" means any nation or government, any state or other political subdivision thereof, any municipal, local, city or county government, any entity exercising executive, legislative, judicial, regulatory or administrative functions of or pertaining to government and any corporation or other entity owned or controlled by any of the foregoing; provided, however, that CDWR shall not be considered to be a Governmental Authority for purposes of this Agreement.

1.29 "Joint AOC Committee" shall have the meaning set forth in Section 7.2.

1.30 "Letter of Credit" shall have the meaning set forth in Section 6.1.2.

1.31 “Monitoring Representative” shall have the meaning set forth in Section 7.3.3.

1.32 “New Materially Significant Technical Information” means information, based on the latest technical information available for a particular Cost Allocation Area, that fundamentally alters the knowledge of the conditions and circumstances of that particular Cost Allocation Area; provided, however, that the following are not considered New Materially Significant Technical Information: (i) new information on the actual volume/mass of contaminants for a particular Cost Allocation Area; and (ii) new information on the projected or actual costs to complete a corrective action ordered by the Division or other applicable Governmental Authority.

1.33 “Normal Business Hours” shall mean the hours from 9:00 a.m. to 5:00 p.m. Pacific Prevailing Time.

1.34 “NVE RG4 Company Allocation” shall have the meaning set forth in Section 2.1.3.

1.35 “Notice of Budget Dispute” shall have the meaning set forth in Section 5.2.

1.36 “Pacific Prevailing Time” means Pacific Standard Time or Pacific Daylight Savings Time, whichever is applicable at the given time.

1.37 “Participation Agreement” shall have the meaning set forth in Recital A.

1.38 “Party(ies)” has the meaning set forth in the Preamble of this Agreement.

1.39 “Past Environmental Costs” means Environmental Costs incurred by NVE through December 31, 2012, but excluding costs associated with the South Lateral Landfill Expansion.

1.40 “Person” means an individual, partnership, corporation, business trust, limited liability company, limited liability partnership, joint stock company, trust, unincorporated association, joint venture or other entity or a Governmental Authority.

1.41 “Pollution Conditions” shall have the meaning set forth in the AOC.

1.42 “Preliminary Report” means the Preliminary Source Area Identification and Characterization Report, dated November 15, 2012.

1.43 “Program Plan” shall have the meaning set forth in Section 7.2.2.

1.44 “Release Agreement” shall have the meaning set forth in Section 10.1.

1.45 “RG4 Company Allocation” shall have the meaning set forth in Section 2.1.3.

1.46 “Section,” and all references in this Agreement to a “Section,” means a numbered section in this Agreement unless otherwise indicated.

1.47 "South Lateral Landfill Expansion" means that phase 1 portion of the permitted class III landfill located on the mesa adjacent to the Station (known as the Mesa Landfill) placed in service in 2013 with a capacity of approximately 1.5 million cubic yards in the NE quarter of the SW quarter and the NW quarter of the SE quarter of Section 7, Township 15S, Range 66E.

1.48 "Station" shall have the meaning set forth in Recital A.

1.49 "Termination Date" shall have the meaning set forth in Recital F.

1.50 "Termination Settlement Agreement" shall have the meaning set forth in Recital F.

1.51 "Total Assurance Amount" shall have the meaning set forth in Section 6.1.

1.52 "TU Credit Amount" shall have the meaning set forth in Section 5.9.1.

1.53 "TU Invoice" shall have the meaning set forth in Section 5.9.

1.54 "TU Invoice Amount" shall have the meaning set forth in Section 5.9.2.

1.55 "Uncontrollable Force" shall mean any cause beyond the control of the Party affected, including but not restricted to failure of or threat of failure of facilities, flood, earthquake, tornado, storm, fire, lightning, epidemic, war, riot, civil disturbance or disobedience, labor dispute, labor or material shortage, sabotage, restraint by court order, which by exercise of due diligence the Party has been unable to overcome.

1.56 "Undisputed Advance Payment Amount" shall have the meaning set forth in Section 5.6.

1.57 "Unit 4" shall have the meaning set forth in Recital A.

1.58 "Unit 1-3 Allocation" shall have the meaning set forth in Section 2.1.2.

1.59 "Unit 4 Allocation" shall have the meaning set forth in Section 2.1.2.

1.60 "Unit Allocation" shall have the meaning set forth in Section 2.1.2.

1.61 "WSJ Prime Rate" shall mean a per annum rate equal to the rate published in the "Money Rates" section of The Wall Street Journal on the day that a decision is rendered by arbitrator(s) under Section 11 of this Agreement.

2 ALLOCATIONS

2.1 The Parties have adopted, by way of compromise, and without prejudice to or waiver of their respective positions in matters unrelated to this Agreement, and without CDWR's admission of any liability or responsibility imposed against it by the AOC, this Agreement to specify the rights and responsibilities of the Parties to each other, with respect to the subject matter of this Agreement, including certain allocations as to Environmental Costs, as follows:

2.1.1 Cost Allocation Areas. The Parties have identified all pertinent Cost Allocation Areas based on all relevant technical information available as of the Execution Date of this Agreement, including the Preliminary Report. All Cost Allocation Areas are identified in Exhibit A.

2.1.2 Unit Allocations. Each Cost Allocation Area shall have a unit allocation ("Unit Allocation"), which is the reasonable estimate, based on the best technical information available for that Cost Allocation Area, of the percentage attributable to Units 1-3 ("Unit 1-3 Allocation") and the percentage attributable to Unit 4 ("Unit 4 Allocation"). The Unit 1-3 Allocation or the Unit 4 Allocation may be zero. All Unit Allocations are identified in Exhibit A.

2.1.3 RG4 Company Allocations. So long as the Unit 4 Allocation is not zero, each Cost Allocation Area shall have a company allocation with respect to Unit 4 ("RG4 Company Allocation"). There shall be a percentage attributable to NVE ("NVE RG4 Company Allocation") and a percentage attributable to CDWR ("CDWR RG4 Company Allocation"). All RG4 Company Allocations are identified in Exhibit A and were agreed to on the basis of one or more equitable allocation principles considering spatial and temporal differences, mass, toxicity, power generation, and contractual terms.

2.2 Additions and Deletions of Cost Allocation Areas.

Subsequent to the Effective Date of this Agreement, as new information is obtained regarding Pollution Conditions at the Station, the Parties may agree to add a new Cost Allocation Area or delete an existing Cost Allocation Area; provided, however, that the addition or deletion of a Cost Allocation Area must be based on New Materially Significant Technical Information. If the Parties agree to add a new Cost Allocation Area, the Parties must also concurrently agree to a Unit Allocation. If a new Cost Allocation Area is added, the Unit Allocation and the Company Allocation shall be determined based on the latest technical information available, including New Materially Significant Technical Information. Exhibit A shall be revised accordingly to reflect any addition or deletion of a Cost Allocation Area.

2.3 Amendment of a Unit Allocation.

Subject to the terms and conditions of this Agreement and subject to the strict compliance with this Section 2.3, either Party may reasonably request to open good faith negotiations to revise the Unit Allocation for any particular Cost Allocation Area.

2.3.1 The requesting Party must make a written request to amend an existing Unit Allocation ("Amendment Request") that shall include the following (i) the proposed revision to the Unit Allocation for a particular Cost Allocation Area and (ii) sufficient detail to support the request, including all New Materially Significant Technical Information and a summary thereof.

2.3.2 The requesting Party must represent in good faith (i) that the Amendment Request is based on New Materially Significant Technical Information obtained by that Party after the time that the existing Unit Allocation was

agreed to by the Parties; and (ii) that the requesting Party reasonably believes that the New Materially Significant Technical Information warrants a change to the Unit Allocation at issue that will result in a significant decrease or increase in the Environmental Costs to be paid by CDWR pursuant to this Agreement.

2.3.3 If an Amendment Request is made, then the Parties shall negotiate in good faith to determine whether a change to the Unit Allocation is warranted. If an agreement has not been reached within ninety (90) days from the time that the Amendment Request is delivered by the requesting Party to the other Party, the requesting Party may then initiate the dispute resolution procedures set forth in Section 11 below. In deciding such a dispute, the arbitrator(s) shall first decide whether there is New Materially Significant Technical Information to support the Amendment Request. If so, the arbitrator(s) will then decide whether the New Materially Significant Technical Information warrants a change to the Unit Allocation at issue that will result in a significant decrease or increase in the Environmental Costs to be paid by CDWR pursuant to this Agreement. If the arbitrator(s) decide(s) that a new Unit Allocation is warranted, then the arbitrator(s) shall also decide the new Unit Allocation. If the arbitrator(s) decide(s) that a new Unit Allocation is not warranted, then the existing Unit Allocation shall remain in place.

2.3.4 Notwithstanding the other provisions of this Section 2.3 to the contrary, the Parties shall, at the request of either Party, reopen allocation negotiations for the Cost Allocation Areas set forth below if an EA Budget includes any Environmental Costs for an Environmental Action taken to remediate Pollution Conditions at such Cost Allocation Areas: (i) Former Diesel AST (850,000-gallon) (AOC Source Area No. SA-12) and (ii) a portion of Mesa Area Groundwater (AOC Source Areas No. MA-1 through MA-6, MA-8, and MA-9).

2.3.5 If a Unit Allocation is modified, either by agreement of the Parties or by a determination in dispute resolution, then Exhibit A shall be amended to reflect such modification. To the extent that there is a reasonable basis and sufficient supporting documentation for doing so, the modified Unit Allocation may be applied retroactively for all Environmental Costs related to the affected Cost Allocation Area that are incurred after December 31, 2012. Adjustments to each Party's Environmental Costs based on modified Unit Allocations, including any credits or debits resulting from retroactive application, shall be made during the next Annual True-Up that takes place after the Unit Allocation has been modified.

2.4 Amendment of a Company Allocation for Specified Cost Allocation Areas.

After the close of calendar year 2017, NVE will complete a one-time revision of the company allocations set forth in Exhibit A for the Cost Allocation Areas set forth below to reflect megawatt-hours generated and attributable to NVE and CDWR,

respectively, during the period beginning January 1, 2013 and ending December 31, 2017:

(i) Unit 4 Cooling Tower (AOC Source Area SA-2);

(ii) Unit 4 Cooling Tower Catch Basin (AOC Source Area SA-3);

(iii) Unit 4 Coal Pile above groundwater level and Unit 4 Coal Pile below groundwater level (part of AOC Source Area SA-4);

(iv) Unit 4 Settling Pond (AOC Source Area SA-7); and

(v) Unit 4 Absorber Area (part of AOC Source Area SA-19).

Upon completion of any revisions necessary as set forth above, and upon approval of such revisions by CDWR, NVE will true-up all invoices previously submitted to CDWR for payment associated with these Cost Allocation Areas and wire any monies owed by NVE to CDWR as a result of such revisions.

3 PAYMENT OF ENVIRONMENTAL COSTS

3.1 EA Payment Escrow

On or before the Closing, an interest-bearing escrow account will be opened with an escrow agent mutually agreeable to the Parties ("EA Payment Escrow"). The cost of the escrow agent and all expenses of the EA Payment Escrow shall be borne equally by the Parties. CDWR is entitled to recoup any interest earned prior to the Closing on the amount CDWR deposits into the EA Payment Escrow. Written "EA Payment Escrow Instructions," in substantially the same form as the attached Exhibit C, consistent with this Agreement, and signed by each of the Parties, shall be delivered to the escrow agent prior to the Closing.

3.2 Payment of Environmental Costs.

3.2.1 Past Environmental Costs. CDWR shall pay One Million Eight Hundred Twenty-Nine Thousand Five Hundred Eighty Two Dollars ($1,829,582) to NVE as CDWR's share of Past Environmental Costs ("CDWR Past Environmental Costs"). On or before Closing, CDWR shall wire the entire amount of CDWR Past Environmental Costs in immediately available funds, to the EA Payment Escrow.

3.2.2 2013 Environmental Costs. CDWR shall pay Nine Hundred Thirty-Three Thousand Four Hundred Twenty-Four Dollars ($933,424) to NVE as CDWR's share of Environmental Costs reasonably anticipated to be incurred during the 2013 calendar year ("CDWR 2013 Environmental Costs"). On or before Closing, CDWR shall wire the entire amount of CDWR 2013 Environmental Costs, in immediately available funds, to the EA Payment Escrow.

3.2.2.1 Except as otherwise provided herein, all terms of this Agreement shall apply to the CDWR 2013 Environmental Costs. Sections 5.1

through 5.6 shall not apply to the CDWR 2013 Environmental Costs.

3.2.3 Landfill Costs. CDWR shall make a one-time payment of Three Million Eight Hundred Seventy-Seven Thousand Dollars ($3,877,000) with respect to the South Lateral Landfill Expansion. CDWR shall make such payment by wire transfer to NVE no later than January 15, 2014. In exchange, CDWR shall receive the right to disposal of 520,000 in-place cubic yards of waste attributable to CDWR pursuant to this Agreement in the South Lateral Landfill Expansion, as determined at the location of excavation. Such payment shall include all landfill operations and maintenance costs, as well as monitoring, regulatory, and closure and post-closure costs. NVE shall indemnify and hold CDWR harmless with respect to any and all claims or liability relating in any way to the South Lateral Landfill Expansion.

3.2.4 Future Environmental Costs. CDWR shall pay its share of Future Environmental Costs in an amount and manner calculated according to and consistent with this Agreement.

3.2.5 Party Allocation of Future Environmental Costs.

3.2.5.1 NVE is solely responsible for all of the Future Environmental Costs allocated to Units 1-3.

3.2.5.2 NVE and CDWR agree to share responsibility for the Future Environmental Costs allocated to Unit 4 as set forth in this Agreement; provided, however, that nothing in this Agreement alters or amends the Parties' agreement under the Termination Settlement Agreement.

3.2.5.3 CDWR's share of Future Environmental Costs is calculated as follows: (i) the total Environmental Cost for any Cost Allocation Area is multiplied by the Unit 4 Allocation for that Cost Allocation Area, and (ii) the product calculated in (i) above is then multiplied by the CDWR RG4 Company Allocation for that Cost Allocation Area.

3.2.5.4 NVE is solely responsible for all Environmental Costs not attributable to CDWR under this Section 3.

4 DELIVERY FROM ESCROW

4.1 Upon written confirmation from each of the Parties to the escrow agent of the EA Payment Escrow that all of the conditions precedent in Section 9.1 of this Agreement have occurred, the entire amount of CDWR Past Environmental Costs and CDWR 2013 Environmental Costs shall be wired from the EA Payment Escrow to NVE.

5 ACCOUNTING AND PAYMENT

5.1 Annual Budget.

On or before March 1 of each year following the Closing, NVE shall deliver to CDWR an annual budget (the "EA Budget") showing the type and amount of Environmental Costs anticipated for the following calendar year ("Budget Year"). In preparing the EA Budget, NVE shall exercise good faith in determining what Environmental Actions and Environmental Costs are reflected in the EA Budget, including reasonably estimating the length of time necessary to complete any Environmental Action. After the EA Budget is delivered to CDWR, the Parties shall meet and confer regarding the contents of the EA Budget. NVE may deliver one or more revised EA Budgets to CDWR on or before August 1 of the year prior to the Budget Year.

5.2 Notice of Budget Dispute.

Provided that CDWR has received an EA Budget in accordance with Section 5.1, CDWR shall notify NVE in writing on or before October 1 of the year prior to the Budget Year of any items on the EA Budget last delivered to CDWR that it disputes ("Notice of Budget Dispute"). CDWR may dispute any Environmental Cost or Environmental Actions disclosed in the EA Budget. The Notice of Budget Dispute shall specifically identify the Environmental Costs and Environmental Actions that are disputed ("Disputed Budget Items"), together with supporting documentation showing the basis for the dispute.

5.2.1 The Parties acknowledge that NVE will consider the Notice of Budget Dispute in making a final determination whether or not to perform work, and the Parties agree that time is of the essence to resolve any budget dispute. The failure by CDWR to deliver a Notice of Budget Dispute on or before October 1 of the year prior to the Budget Year shall constitute a waiver of any future right to contest or dispute the items on the EA Budget for that Budget Year, provided that the basis for disputing the item has been reasonably disclosed to CDWR in the EA Budget.

5.3 EA Budget Revision.

If CDWR delivers a Notice of Budget Dispute in compliance with Section 5.2 above, NVE may deliver a revised EA Budget on or before November 15 of the year prior to the Budget Year. In such revised EA Budget, NVE may revise, adjust, modify or delete, subject to the provisions set forth in this Section 5, but shall not increase or add any Environmental Costs or Environmental Actions in any such revised EA Budget once CDWR has submitted a Notice of Budget Dispute.

5.4 Continued Budget Disputes.

The Parties shall continue to negotiate in good faith prior to January 1 of the Budget Year and may agree to resolve any portion of any Disputed Budget Items. If the Parties resolve any portion of the Disputed Budget Items, NVE shall amend, if necessary, the latest EA Budget consistent with such agreed upon resolution of the Notice of Budget

Dispute. If the Parties are unable to resolve the dispute, then the remaining Disputed Budget Items will be resolved as follows:

5.4.1 If an agreement has not been reached as to all Disputed Budget Items before January 1 following delivery of the Notice of Budget Dispute, CDWR may initiate the dispute resolution procedures set forth in Section 11 below.

5.4.2 If CDWR does not initiate dispute resolution under Section 11 on or before March 1 of the Budget Year, CDWR shall have waived its right to make such a dispute. In such event, after March 1 of that Budget Year, the Parties shall instruct the escrow agent to immediately distribute to NVE the Disputed Advance Payment Amount.

5.4.3 If CDWR initiates dispute resolution with respect to only a portion of Disputed Budget Items on or before March 1 of the Budget Year, CDWR shall have waived its right to dispute the other portion of the Disputed Budget Items. In such event, after March 1 of that Budget Year, the Parties shall instruct the escrow agent to immediately distribute to NVE the portion of the Disputed Advance Payment Amount that is not subject to the dispute resolution.

5.4.4 Upon resolution of any Disputed Advance Payment Amount, either by agreement of the Parties or through dispute resolution, the Parties shall instruct the escrow agent to immediately distribute any amount of such Disputed Advance Payment Amount in the EA Payment Escrow as follows:

(i) the amount determined to be an Environmental Cost owed by CDWR shall be delivered from escrow to NVE, together with any interest earned on such amount from the EA Payment Escrow.

(ii) the amount determined to not be an Environmental Cost owed by CDWR shall be delivered from escrow to CDWR, together with any interest earned on such amount from the EA Payment Escrow.

5.5 Final EA Budget.

The latest version of the EA Budget submitted or revised by NVE pursuant to Sections 5.1, 5.3, or 5.4 above, or amended pursuant to Section 5.4 above, shall be deemed the final EA Budget ("Final EA Budget") for the particular Budget Year.

5.5.1 Under no circumstances shall NVE's election to delete or defer any Environmental Cost(s) in the Final EA Budget be interpreted as: (i) a waiver of its right to include such Environmental Cost in a subsequent EA Budget; or (ii) an admission that such action is not an Environmental Action. If circumstances warrant, NVE may include such Environmental Costs in an EA Budget in a future calendar year (which shall be subject to CDWR's right to dispute under this Section 5).

5.5.2 If, in the Final EA Budget for any Budget Year, NVE has deleted or deferred any Environmental Cost(s) that was disputed by CDWR, then either Party may (but is not required to) initiate dispute resolution under Section 11 below and seek a declaratory judgment with respect to such Environmental Cost(s), for purposes of all future EA Budgets prepared under this Agreement.

5.6 Advance Payment.

As set forth in greater detail below, CDWR shall pay, by wire, the full amount of CDWR's share of the Final EA Budget ("CDWR Advance Payment"). Any amount that is undisputed, including any particular line-item in the Final EA Budget that is undisputed, shall be referred to herein as the "Undisputed Advance Payment Amount." Any portion of the CDWR Advance Payment Amount that reflects payment for Disputed Environmental Costs shall be referred to herein as the "Disputed Advance Payment Amount." In each Budget Year, CDWR shall pay the entire CDWR Advance Payment for that year in two, equal payments, as follows:

5.6.1 On or before January 1 of the Budget Year, CDWR shall wire (i) one-half of the Undisputed Advance Payment Amount directly to NVE and (ii) one-half of the Disputed Advance Payment Amount, if any, to the EA Payment Escrow.

5.6.2 On or before July 1 of the Budget Year, CDWR shall wire (i) the other half of the Undisputed Advance Payment Amount directly to NVE and (ii) the other half of the Disputed Advance Payment Amount, if any, to the EA Payment Escrow.

5.7 Monthly Cost Accounting.

On a monthly basis, NVE will provide, at its expense, to CDWR an accounting of the Environmental Costs NVE has incurred for the prior month and year-to-date, allocated to each Cost Allocation Area, with reasonably detailed documentation.

5.8 Work Outside the EA Budget.

5.8.1 The Parties acknowledge that it may prove necessary or efficient to perform work during a particular Budget Year that was not anticipated, or not to perform work that was anticipated, in the Final EA Budget for that Budget Year. The Parties further acknowledge that CDWR shall have an opportunity to dispute such work, in the manner described in this Section 5.8.

5.8.2 NVE shall notify CDWR of any Environmental Action it performs or Environmental Cost that it incurs that was not included in the Final EA Budget. NVE may (but is not required to) request CDWR approval to take an Environmental Action and incur an Environmental Cost that was not included in the Final EA Budget. Any such request shall be in writing. If CDWR does not concur with the Environmental Cost, CDWR shall deliver a written notice to NVE, within sixty (60) days of CDWR's receipt of such written request, stating CDWR's disapproval of the Environmental Cost and setting forth the basis for the disapproval. Failure by CDWR to respond to the request within sixty (60) days shall constitute CDWR's approval of the request.

5.8.3 If CDWR fails to provide a written notice as set forth in Section 5.8.2 above, then CDWR shall be responsible for its portion of the Environmental Cost. Payment by CDWR, however, shall be made as part of the Annual True-Up set forth in Section 5.9.

5.8.4 If CDWR delivers a timely notice stating CDWR's disapproval of the Environmental Cost, then NV Energy may or may not, in its sole discretion, perform the additional work.

5.8.5 If NV Energy performs work that was not included in the Final EA Budget, regardless of CDWR's approval or disapproval, NV Energy shall include the cost of such work in the Annual True-Up set forth in Section 5.9; provided, however, that CDWR shall retain its ability to protest the amount and purpose of the cost, as well as the inclusion of such cost, under Section 5.10.

5.9 Annual True-Up.

After the close of each Budget Year, at its own expense, NVE will true-up the actual Environmental Costs to the CDWR Advance Payment for the Budget Year ("Annual True-Up"). On or before March 1 of the year following the applicable Budget Year, NVE shall deliver to CDWR a final invoice summarizing the Annual True-Up for that immediately prior Budget Year ("TU Invoice"). If the TU Invoice has an amount owing by CDWR, it shall provide detail of the amount owed by CDWR to NVE. If the TU Invoice has a credit to CDWR, it shall provide details of the amount owed by NVE to CDWR.

5.9.1 NVE will remit the amount of any credit to CDWR ("TU Credit Amount") within 30 days after the date of the TU Invoice as follows: (1) if NVE has received the CDWR funds for such Environmental Costs (either directly or from the EA Payment Escrow), NVE shall wire the TU Credit Amount in immediately available funds to CDWR; and (2) if the CDWR funds for such Environmental Costs remain in the EA Payment Escrow, NVE shall deliver instructions to the escrow agent to release the TU Credit Amount to CDWR, together with any interest earned in the EA Payment Escrow on the TU Credit Amount.

5.9.2 Without limiting its rights under Section 5.10 below, CDWR will remit the amount of the TU Invoice to NVE ("TU Invoice Amount") in immediately available funds within 30 days after the date of the TU Invoice as follows: (1) if an Environmental Cost related to the TU Invoice Amount (a) was previously disputed and the Disputed Advance Payment Amount remains unresolved at the time TU Invoice Amount is due or (b) was work outside the Final EA Budget that CDWR timely contested pursuant to the provisions of Section 5.8.2, then CDWR shall wire the portion of the TU Invoice Amount related to such Environmental Cost to the EA Payment Escrow; and (2) in all other cases, CDWR shall wire the TU Invoice Amount directly to NVE.

5.9.2.1 If any portion of the TU Invoice Amount is deposited in the EA Payment Escrow under Section 5.9.2(1)(b), CDWR may following

such deposit initiate dispute resolution under Section 11. If CDWR does not initiate dispute resolution under Section 11 within three (3) months after any amount is deposited in the EA Payment Escrow under Section 5.9.2(1)(b), CDWR shall have waived its right to further dispute such amount. In such event, the Parties shall instruct the escrow agent to immediately distribute to NVE the amount deposited in the EA Payment Escrow under Section 5.9.2(1)(b).

5.10 Annual Audit.

5.10.1 Following the Annual True-Up, CDWR may perform an audit of Environmental Costs billed to it in the previous Budget Year. CDWR shall have reasonable access to accounting information and documentation to perform such an audit; provided, however, that CDWR shall reimburse NVE for all reasonable costs incurred by NVE with respect to facilitating CDWR's audit.

5.10.2 Within twelve (12) months after the date of CDWR's receipt of the TU Invoice for any given year, CDWR may dispute any portion of the Annual True-Up by delivering written notice of a dispute of the Annual True-Up. Such CDWR notice must provide results of the audit to NVE and provide sufficient detail to validate the dispute. If CDWR does not deliver such written notice within twelve (12) months after the date of the TU Invoice, the Annual True-Up shall be considered final and not subject to dispute.

5.10.3 Upon receipt of any written notice of a dispute of the TU Invoice, the Parties shall negotiate in good faith for a period of at least ninety (90) days. At the end of such period, if an agreement has not been reached to resolve the dispute, either Party may then initiate the dispute resolution procedures set forth in Section 11 below. If a Party does not initiate a dispute within one hundred fifty (150) days after receipt of the written notice of dispute, the TU Invoice shall be considered final and not subject to further dispute.

6 FINANCIAL ASSURANCES

6.1 Financial Assurance.

CDWR will provide a total amount of Twenty-Four Million Dollars ($24,000,000) (the "Total Assurance Amount") in financial assurances as security for the full and faithful performance by CDWR of all of its obligations under this Agreement. As set forth in greater detail below, the Total Assurance Amount may have one or both of the following components: (i) cash in an escrow account, as established below, or (ii) a letter of credit, on the terms provided below. So long as the Total Assurance Amount is maintained at all times, CDWR shall have sole discretion regarding the amounts to be committed under each financial assurance component.

6.1.1 EA Assurance Escrow. An interest bearing escrow may be established with a mutually agreeable escrow agent for the purpose of holding funds subject to

the terms and conditions of this agreement (the "EA Assurance Escrow"). CDWR shall solely bear the costs of maintaining the EA Assurance Escrow. CDWR shall retain all interest earned in the EA Assurance Escrow. CDWR shall deposit funds to the EA Assurance Escrow in the amount sufficient to maintain at all times, in combination with the amount of the Letter of Credit, the Total Assurance Amount. Distributions from the EA Assurance Escrow shall be authorized as set forth in this Agreement and pursuant to the "EA Assurance Escrow Instructions," in substantially the same form as the attached Exhibit D. No other distributions shall be authorized except by written instruction of both NVE and CDWR. Upon written acknowledgement, from both CDWR and NVE, to the escrow agent, of the termination of this Agreement, as set forth in Section 12, the balance of funds in the EA Assurance Escrow, including any interest earned, shall be distributed to CDWR.

6.1.2 Letter of Credit. If CDWR elects to obtain a letter of credit in any amount, CDWR shall deliver to NVE an irrevocable and unconditional negotiable letter of credit (the "Letter of Credit"), in substantially the same form as the attached Exhibit E. Such Letter of Credit shall be payable at sight, in the amount sufficient to maintain at all times, in combination with the cash deposited in the EA Assurance Escrow, the Total Assurance Amount. Such Letter of Credit shall be issued by a solvent nationally recognized United States bank or financial institution with a long term debt rating of at least A+ or higher, (as rated by Standard & Poor's) or A1 (as rated by Moody's Investors Service) that is under the supervision of the Superintendent of Banks of the State of California, or a national banking association, from which NVE may draw on such Letter of Credit. The Letter of Credit shall (i) be irrevocable, unconditional, and payable at sight; (ii) provide NVE the right to draw down an amount up to the face amount of the Letter of Credit upon the presentation to the issuing bank of NVE's statement that such amount is due to NVE; (iii) be subject to the International Standby Practices, ICC Publication No. 590; and (iv) permit partial draws in accord with this Agreement.

6.1.3 Replacements. CDWR may replace an existing Letter of Credit with a subsequent Letter of Credit so long as the replacement Letter of Credit is issued and in full force and effect within thirty (30) days prior to the expiration or termination of the prior Letter of Credit. Provided, however, if a replacement Letter of Credit has not been obtained within thirty (30) days prior to the expiration or termination of the prior Letter of Credit and CDWR has not deposited the Total Assurance Amount in the EA Assurance Escrow, then NVE shall be entitled to immediately draw upon the entire amount of the Letter of Credit. If there is a draw upon the Letter of Credit under this Section 6.1.3, then the funds drawn shall be wired to the EA Assurance Escrow and deposited there to fulfill CDWR's obligation to maintain the Total Assurance Amount under this Agreement.

6.1.4 Change in Rating. If the long term debt rating of the bank or institution issuing the Letter of Credit falls below A+ (as rated by Standard & Poor's) or A1 (as rated by Moody's Investors Service), then CDWR shall, within thirty (30) days of such a downgrade by either credit rating agency, obtain a new Letter of Credit which fully satisfies the conditions set forth in Section 6.1.2 (or, at CDWR's discretion, deposit to the EA Assurance Escrow an amount equal to the Total Assurance Amount).

6.1.5 Satisfaction of Financial Assurances. On or before Closing, CDWR shall provide financial assurances in the Total Assurance Amount by depositing funds into the EA Assurance Escrow and/or delivering the Letter of Credit (or a combination thereof). NVE shall have no right to access any of the financial assurances until after the Closing and then only pursuant to the terms of this Section 6. The Total Assurance Amount shall be maintained at all times. Except as specifically provided in Section 6.1.6 and 6.1.9, a failure to maintain the Total Assurance Amount for any amount of time shall be a material breach of this Agreement.

6.1.6 Increase for Failure to Maintain the Total Assurance Amount. If the Total Assurance Amount is not maintained, except as specifically provided in Section 6.1.8, then NVE shall, without waiving any other remedies available under this Agreement, send written notice to CDWR of the failure to maintain the Total Assurance Amount. Upon receipt of such a notice, CDWR shall have thirty (30) days to cure the failure and prevent any increase in the Total Assurance Amount pursuant to this Section 6.1.6. If there are not financial assurances equaling the Total Assurance Amount at the end of the thirty (30) day period, then the Total Assurance Amount shall increase by Two Million Dollars ($2,000,000) for the remainder of the term of this Agreement

6.1.7 Mixture of Financial Assurances. The sum of the financial assurances in the EA Assurance Escrow and the Letter of Credit shall, at all times, be at least equal to the Total Assurance Amount. So long as the sum of the cash held in the EA Assurance Escrow and the amount of the Letter of Credit are at least equal to the Total Assurance Amount, CDWR may, in CDWR's sole discretion, vary the amount of either component of the financial assurances in the EA Assurance Escrow; provided, however that (i) no amount shall be disbursed from the EA Assurance Escrow prior to delivery of a new Letter of Credit to NVE in the amount necessary to maintain the Total Assurance Amount after such disbursement; and (ii) no Letter of Credit shall be reduced or extinguished prior to delivery to the EA Assurance Escrow of cash in the amount necessary to maintain the Total Assurance Amount after such change to the Letter of Credit.

6.1.8 Disbursements from the EA Assurance Escrow and Draws on the Letter of Credit. If CDWR does not pay any CDWR Advance Payment due under Section 5.6 or the TU Invoice Amount after an Annual True-Up due under Section 5.9 or any other amount due under this Agreement, NVE may immediately call upon the financials assurances provided herein, by either (i)

instructing the escrow agent for the EA Assurance Escrow to distribute funds pursuant to the escrow instructions or (ii) drawing upon the Letter of Credit, subject to the limitations in the Letter of Credit. To initiate a distribution of funds from the EA Assurance Escrow or a draw on the Letter of Credit, NVE must first provide written notice to CDWR in substantially the same form as the attached Exhibit F specifying NVE's intent to invoke this Section 6.1.8 and specifying the amount CDWR has failed to pay. CDWR shall have twenty (20) Business Days after NVE's delivery of the written notice to cure the circumstance set forth in the written notice. If CDWR fails to cure the circumstances set forth in the written notice within such time, NVE shall be entitled to receive an immediate distribution from the EA Assurance Escrow, consistent with the escrow instructions, or to immediately draw from the Letter of Credit, consistent with its terms, in the following amount: the sum of (a) the amount set forth in the notice and (b) an amount equaling two percent (2%) of the amount set forth in the notice.

6.1.9 Replenishment of Total Assurance Amount. If any disbursement is made under Section 6.1.8, CDWR shall, within thirty (30) days of the disbursement made under Section 6.1.8, provide financial assurances so that the sum of the cash in the EA Assurance Escrow and the Letter of Credit are at least equal to the Total Assurance Amount.

6.1.10 Adjustments to the Total Assurance Amount. The Total Assurance Amount may be modified as follows:

6.1.10.1 Material Change in Anticipated Costs. Upon the three year anniversary of the Effective Date of this Agreement, and each subsequent two year anniversary during the term of this Agreement, the Parties will negotiate in good faith to determine whether to modify the Total Assurance Amount. A modification of the Total Assurance Amount shall be warranted only if, considering all circumstances then-existing, including any New Materially Significant Technical Information, there has been significant decrease or increase in estimated Environmental Costs to be paid by CDWR pursuant to this Agreement. In determining whether there has been a been significant decrease or increase in estimated total Environmental Costs to be paid by CDWR pursuant to this Agreement, the estimated magnitude, and any changes therein, of Pollution Conditions at all Cost Allocation Areas and the estimated future costs, and any changes thereto, shall be considered. Upon agreement of the Parties, the Total Assurance Amount may increase or decrease. If the Parties cannot agree on whether to modify the Total Assurance Amount, after a period of at least sixty (60) days in which they shall negotiate in good faith, either Party may then initiate the dispute resolution procedures set forth in Section 11 below.

6.1.10.2 CDWR Credit Rating. If CDWR's credit rating on any uninsured

revenue bond falls below "A+" (as determined by Standard & Poor's), or "A1" (as determined by Moody's), or "A+" (as determined by Fitch), then the Total Assurance Amount shall be increased to one and one-half times greater than the then-existing Total Assurance Amount, and, within thirty (30) days following written notice from NVE demanding an increase in the Total Assurance Amount, CDWR shall deposit additional funds in the EA Assurance Escrow and/or deliver a new or amended Letter of Credit in an amount sufficient to satisfy the new Total Assurance Amount upon the same terms as set forth above. If, after a degradation of CDWR's credit rating and increase in the Total Assurance Amount under the terms of this Section 6.1.10.2, CDWR's credit rating on all existing uninsured revenue bond subsequently improves to the rating of at least "AA" as determined by Standard & Poor's, or "Aa2" as determined by Moody's, or "AA" as determined by Fitch, then the Total Assurance Amount shall return to the amount it was prior to the degradation in credit rating.

7 ADMINISTRATION

7.1 Party of Record.

NVE is the party-of-record with the Division for compliance with the AOC, and NVE is ultimately responsible for compliance with all obligations under the AOC and for determining the means to achieve such compliance. Except as otherwise provided for below, NVE has the sole authority to negotiate with the Division and determine what Environmental Actions are necessary and appropriate under the AOC. Each Party is solely responsible for the costs and expenses it incurs in connection with its communications and coordination with the other Party relating to the AOC and the administration of this Agreement, including, but not limited to, the activities conducted pursuant to this Section 7.

7.1.1 Consistent with the objectives of the AOC and in concurrence with the Division, NVE will determine what Environmental Actions are necessary and appropriate and will perform the Environmental Actions in accordance with prudent and Commercially Reasonable Efforts. In making such determinations and performing such Environmental Actions, NVE shall reasonably communicate and coordinate with CDWR, as set forth below.

7.1.2 Nothing in this Agreement shall limit CDWR's rights and ability to individually meet with and provide comment to the Division and/or any other regulatory entity regarding any actions under the AOC. Further, nothing in this Agreement shall limit CDWR's rights and ability to enter into a separate agreement and/or become a signatory to the AOC with the Division. To the extent that CDWR becomes (i) a signatory to the AOC; (ii) a party-of-record to another environmental agreement with the Division regarding the Pollution Conditions; or (iii) subject to an order issued by the Division regarding the

Pollution Conditions, then NVE no longer will have the sole authority as between it and CDWR to negotiate with the Division and determine what Environmental Actions are necessary and appropriate under the AOC and all provisions of this Section 7 providing that NVE has such sole authority will be revoked and rendered null and void with respect to any portion of the AOC for which CDWR becomes responsible. In such an event, all other terms and conditions of this Agreement will remain in full force and effect.

7.2 Joint AOC Committee

During the term of this Agreement, there shall be a "Joint AOC Committee" for the purpose of facilitating effective cooperation and exchange of information and of providing consultation on a prompt and orderly basis between the Parties. The Joint AOC Committee shall consist of one representative duly authorized and appointed by each Party. Each Party shall designate its representative within ten (10) days after the Effective Date by giving written notice to the other Party and shall also designate one or more alternates to act as its representative on the Joint AOC Committee in the absence of the regular member. The Joint AOC Committee member may designate in writing another representative to act on specified occasions with respect to specific matters. The chairperson of the Joint AOC Committee shall be the NVE representative who shall be responsible for presiding over meetings of the Joint AOC Committee.

7.2.1 The Joint AOC Committee will meet at least quarterly, to discuss current AOC status, budgets and variance reporting, costs incurred, work related to compliance with the AOC, and implementation planning.

7.2.2 NVE will develop, maintain, and communicate an action plan for implementing the AOC ("Program Plan") to the Joint AOC Committee that reflects known and reasonably anticipated information. At a minimum, the Program Plan will include scope, schedule, and cost forecasts for the current Budget Year and subsequent two years. In preparing the Program Plan, NVE shall exercise good faith in determining what Environmental Actions are needed and reasonably estimating the length of time necessary to complete any Environmental Action.

7.2.3 At any time, CDWR may suggest, through the Joint AOC Committee, that NVE take an Environmental Action or incur an Environmental Cost that was not contemplated or included in any EA Budget.

7.2.4 In all matters related to AOC compliance, and specifically in meetings of the Joint AOC Committee, NVE must consider in good faith CDWR recommendations relating to the determination of what Environmental Actions are reasonable and necessary, the method of performing Environmental Actions, and the manner in which Environmental Actions are proposed to the Division in seeking the concurrence of the Division.

7.3 Oversight

7.3.1 Each Party shall designate an "EA Manager" within ten (10) days after the Effective Date by giving written notice to the other Party. The EA Managers will serve as the point of contact between the Parties on a day-to-day basis between meetings of the Joint AOC Committee. Each of the EA Managers shall make reasonable efforts to provide information requested by the other EA Manager.

7.3.2 CDWR's EA Manager may consult with and make recommendations to NVE's EA Manager; provided however that nothing in this Section shall contradict NVE's sole authority to agree with the Division in determining what Environmental Actions are reasonable and necessary under the AOC, except as provided for in Section 7.1.2 of this Agreement.

7.3.3 CDWR's EA Manager may monitor the progress and performance of Environmental Actions. CDWR may designate, by giving written notice to NVE's EA Manager, a representative assigned to perform such monitoring ("Monitoring Representative").

7.3.4 CDWR's EA Manager and CDWR's Monitoring Representative shall be allowed reasonable access to the facilities on the plant site; provided, however, CDWR's EA Manager and CDWR's Monitoring Representative may not supervise or direct any of NVE's employees or any of the consultants and remediation contractors performing any work under the direction of NVE.

7.4 Documents

7.4.1 NVE will provide to CDWR draft copies of all substantive, non-administrative submittals to the Division required under the AOC, and, will make Commercially Reasonable Efforts to provide reasonably sufficient time for CDWR review and comment. In so doing, NVE will not be restricted in submitting any required submittal to the Division on the timeframe requested by the Division, nor will it be obligated to incorporate any comment or edit proposed by CDWR except as may be required following completion of dispute resolution procedures set forth in this Agreement.

7.4.2 NVE shall provide to CDWR copies of all submittals and formal correspondence with the Division related to the AOC, within a reasonable period of time but no more than fourteen (14) days after such filing. If NVE files any documents related to the AOC or this Agreement with any other regulatory agency, and such documents were not previously provided to CDWR and are not otherwise publically available to CDWR, NVE shall provide such documents to CDWR within seven (7) days after a written request from CDWR.

7.4.3 In addition to the rights set forth in Section 14.11, CDWR may submit to NVE special requests it may have to receive additional accounting records, research, or other information related to the AOC beyond those materials expressly provided for in this Agreement. NVE shall use its Commercially Reasonable

Efforts to the extent possible to reasonably respond to such special requests. CDWR shall reimburse NVE for any reasonable expenses incurred in fulfilling such special requests. Notwithstanding the above, NVE is not obligated to develop or produce documents or data not otherwise in existence.

7.4.4 Except as provided in Section 14.7 of this Agreement, all document requests, submittals, notices, consents, and other communications hereunder shall be in writing and shall be sent by email to the following person or to his/her designee as subsequently specified by written notice to the other Party:

For NVE: NV Energy
Generation Partnership Contracts
6226 W. Sahara Ave.
Las Vegas, Nevada 84146
Mail Station #25
E-mail: acasey@nvenergy.com

Attn: Ann Casey

For CDWR: California Department of Water Resources
1416 Ninth Street
Sacramento, California 95814
E-mail: mark.andersen@water.ca.gov

Attn: Mark Andersen, P.E.

8 REPRESENTATIONS AND WARRANTIES

8.1 Representations and Warranties of NVE.

NVE represents and warrants to CDWR that:

8.1.1 Organization; Good Standing.

NVE is a corporation duly organized, validly existing and in good standing under the laws of the jurisdiction of its organization.

8.1.2 Authority; Enforceability.

NVE has the absolute and unrestricted right, authority, power and capacity to (i) execute and deliver this Agreement and any document to be executed by NVE in connection herewith and (ii) perform its obligations hereunder and thereunder. The execution and delivery of this Agreement have been duly and validly authorized by NVE. This Agreement has been duly and validly executed and delivered by NVE and constitutes, and upon execution and delivery by NVE, the legal, valid and binding obligations of NVE, enforceable against it in accordance with its terms.

8.1.3 Consents and Approvals.

Except as otherwise set forth in the AOC or this Agreement, no approval, consent, license, permit, waiver, or other authorization is required from any Governmental

Authority or any other Person in connection with (i) the execution or delivery by NVE of this Agreement or (ii) the performance of NVE's obligations under this Agreement.

8.2 Representations and Warranties of CDWR.

CDWR represents and warrants to NVE that:

8.2.1 Organization; Good Standing.

CDWR is an agency of the State of California and has the requisite power and authority to perform all its obligations under this Agreement.

8.2.2 Authority; Enforceability.

CDWR is authorized, pursuant to the Central Valley Project Act (CA Water Code Section 11100 et seq.), to (i) execute and deliver this Agreement and each certificate, document and agreement to be executed by CDWR in connection herewith and (ii) perform its obligations hereunder and thereunder. The execution and delivery of this Agreement have been duly and validly authorized and approved and constitute, and upon execution and delivery by CDWR, the legal, valid and binding obligations of CDWR, enforceable against it in accordance with its terms.

8.2.3 Consents and Approvals.

Except as otherwise set forth in this Agreement, no approval, consent, license, permit, waiver, or other authorization is required from any Governmental Authority or any other Person in connection (i) the execution or delivery by CDWR of this Agreement or (ii) the performance of CDWR's obligations under this Agreement.

9 CONDITIONS PRECEDENT TO THIS AGREEMENT BECOMING EFFECTIVE

9.1 Conditions Precedent.

For Closing to occur and this Agreement to become effective, and to obligate the Parties in accordance with the terms and conditions of this Agreement, the following must occur: (i) on or before the Closing, CDWR must pay to the EA Payment Escrow the Past Environmental Costs pursuant to Section 3.2.1; (ii) on or before the Closing, CDWR must pay to the EA Payment Escrow the CDWR 2013 Environmental Costs pursuant to Section 3.2.2.; (iii) on or before the Closing, CDWR must provide the Total Assurance Amount either through payment of cash to the EA Assurance Escrow or provision of a Letter of Credit, or a combination thereof; (iv) on or before the Closing, NVE shall provide an EA Budget to CDWR for calendar year 2014 in such a manner as to allow CDWR sufficient time to review and exercise its rights as provided in Section 5 of this Agreement; and (v) there must be a Closing of the Termination Settlement Agreement and the funds sought to be paid by one Party to the other Party at the Closing, pursuant to the Termination Settlement Agreement, must take place. This Agreement will not become effective until each and every condition is satisfied.

10 RELEASE

10.1 Release.

At any time, the Parties may negotiate and agree upon terms and conditions for an agreement contemplating an amount to be paid in one lump sum, in installments, or upon completion of some other mutually agreeable financial instrument or insurance policy to release CDWR of all further obligations under this Agreement (the "Release Agreement"). Upon execution and full performance of a Release Agreement, NVE shall fully release CDWR from any continued obligations under this Agreement or with respect to financial responsibility for any payment or costs incurred under the AOC and shall indemnify CDWR for any claims by other Persons related to or arising from the Pollution Conditions and/or the AOC. In such an event, NVE shall deliver documentation of the Release Agreement in a form mutually agreed upon by the Parties.

11 DISPUTE RESOLUTION

11.1 Meet and Confer.

Unless otherwise specified in this Agreement, prior to making any demand for arbitration, the Parties agree to meet and confer for a period of at least sixty (60) days; provided, however, that this period may be extended by mutual agreement or by the terms of this Agreement with respect to specific disputes identified herein. The time period to meet and confer under this Agreement shall begin upon the date written notice from one Party is received by the other Party. The written notice constitutes the initiation of dispute resolution and shall specifically reference the need to meet and confer under this Section 11.1 and shall describe the issue(s) in dispute.

11.2 Arbitration.

Any and all controversies or claims arising out of or relating to this Agreement, or the breach thereof, shall be settled by binding arbitration administered by the American Arbitration Association in accordance with its Commercial Arbitration Rules. Judgment on the award rendered by the arbitrator(s) may be entered in any court having jurisdiction thereof. For any dispute involving less than One Million Dollars ($1,000,000) as the amount in controversy, there shall be one neutral arbitrator, named in accordance with such rules. For any dispute involving more than One Million Dollars ($1,000,000) as the amount in controversy, there shall be three neutral arbitrators, named in accordance with such rules. The arbitrator(s) will be selected from a panel of persons with at least ten years' experience in litigation and with environmental issues. Either Party may make a demand for arbitration after the period to meet and confer under Section 11.1 has expired.

11.2.1 Prevailing Party. Subject to the limitations and conditions set forth below, the arbitrator(s) shall award to the prevailing Party the administrative fees and the fees of the arbitrator(s); in addition, the arbitrator(s) shall award to the prevailing Party other reasonable pre-award expenses of the arbitration, including travel expenses, copying and telephone, witness fees, and attorneys' fees, up to a total maximum amount (inclusive of all such costs and fees

identified in this Section 11.2.1.) of $150,000 per dispute in a one arbitrator proceeding and $250,000 per dispute in a three arbitrators proceeding.

11.2.1.1 In the event the arbitrator(s) hear(s) a dispute regarding an Amendment Request pursuant to Section 2.3.3, each Party shall specify a proposed Unit Allocation with an explanation supporting that amount, and the arbitrator(s) shall select one of the proposed Unit Allocations in their decision. The Party whose proposed Unit Allocation is selected by the arbitrator(s) is the prevailing Party.

11.2.1.2 In the event the arbitrator(s) hear(s) a dispute regarding a Disputed Advance Payment Amount pursuant to Section 5.4.1 and Section 5.6, then (i) CDWR shall be the prevailing Party for purposes of this Section 11 if, and only if, the entire Disputed Advance Payment Amount is remitted to CDWR; and (ii) NVE shall be the prevailing Party for purposes of this Section 11 if, and only if, the entire Disputed Advance Payment Amount is awarded to NVE.

11.2.1.3 In the event the arbitrator(s) hear(s) a dispute regarding whether to modify the Total Assurance Amount pursuant to Section 6.1.10.1, each Party shall specify a proposed Total Assurance Amount with an explanation supporting that amount, and the arbitrator(s) shall select one of the proposed Total Assurance Amounts in their decision. The Party whose proposed Total Assurance Amount is selected by the arbitrator(s) is the prevailing Party.

11.2.2 Interest. The arbitrator(s) shall award prejudgment and post-judgment interest as allowed by law. Interest shall be computed as simple interest, with the rate of interest at the WSJ Prime Rate plus one percent (1%).

11.2.2.1 In the event the arbitrator(s) hears a dispute regarding a Disputed Advance Payment Amount pursuant to Section 5.4.1 and Section 5.6, then interest (including any interest earned in the EA Payment Escrow and distributed in accordance with Section 5.4.4) shall be paid as follows: (i) NVE shall pay to CDWR interest from the date of initial payment to the EA Payment Escrow on any amount of the Disputed Advance Payment Amount determined by the arbitrator(s) to not be an Environmental Cost; (ii) CDWR shall pay to NVE interest from the date of initial payment to the EA Payment Escrow on any amount of the Disputed Advance Payment Amount determined by the arbitrator(s) to be an Environmental Cost.

11.2.2.2 In the event the arbitrator(s) hear(s) a dispute regarding a TU Invoice pursuant to Section 5.10.3, then interest (including any interest earned in the EA Payment Escrow and distributed in accordance with Section 5.4.4) shall be paid as follows: (i) NVE shall pay to CDWR interest from the date of initial payment of the

TU Invoice on any amount awarded to CDWR as a result of the TU Invoice dispute; (ii) CDWR shall pay to NVE interest from the date payment was due under the TU Invoice on any amount awarded to NVE as a result of the TU Invoice dispute.

11.2.3 Confidentiality. Except as may be required by law, neither a Party nor the arbitrator(s) may disclose the existence, content, or results of any arbitration hereunder to any Person other than the Parties without the prior written consent of both Parties.

12 TERMINATION

12.1 Duration and Termination.

This Agreement will become effective upon Closing and will continue in full force and effect until terminated under this Section 12.

This Agreement will terminate at the earlier of: (i) fulfillment of all of the obligations under the AOC and the termination of the AOC as acknowledged by a written notice from the Division that all obligations under the AOC have been fulfilled, or (ii) the execution and full performance of a Release Agreement under Section 10.1, or (iii) otherwise upon mutual agreement by the Parties.

12.2 Survival.

This Agreement will not terminate for any other reason not enumerated in Section 12.1.

13 RELATIONSHIP OF PARTIES:

13.1 No Joint Venture.

Nothing herein contained shall ever be construed to create an association, joint venture, trust, or partnership, or to impose a trust or partnership covenant, obligation or liability on or with regard to anyone or both of the Parties. Each Party shall be individually responsible for its own covenants, obligations and liabilities as herein provided. Neither Party shall be under the control of or shall be deemed to control the other Party.

14 GENERAL PROVISIONS

14.1 Uncontrollable Forces:

14.1.1 Other than the obligation of a Party to make payments as provided in this Agreement, no Party shall be considered to be in default in the performance of any of its obligations under this Agreement when a failure of performance is due to an Uncontrollable Force.

14.1.2 Nothing contained herein shall be construed so as to require a Party to settle any strike or labor dispute in which it may be involved.

14.1.3 In the event any Party is rendered unable to fulfill any of its obligations under this Agreement by reason of an Uncontrollable Force, such Party shall give prompt written notice of such fact to the other Party and shall exercise due diligence to remove such inability with all reasonable dispatch.

14.1.4 In such event, the Parties shall diligently and expeditiously determine how they may equitably proceed to carry out the objectives of this Agreement.

14.2 Entire Agreement.

This Agreement (including all exhibits), constitutes the entire agreement and understanding of the Parties hereto in respect of the subject matter hereof. The exhibits attached hereto are an integral part of this Agreement and are incorporated by reference herein. This Agreement supersedes all prior agreements, understandings, promises, representations and statements between the Parties and their representatives with respect to the subject matter of this Agreement.

14.3 Construction.

14.3.1 Unless the context requires otherwise, the word “including” and variations thereof mean including without limitation, the words “hereof” and “herein,” and similar terms refer to this Agreement as a whole and not any particular Section, and any reference to a applicable law shall include, unless otherwise stated, any amendment or successor thereto and any rules and regulations promulgated thereunder.

14.3.2 Currency amounts are in U.S. Dollars.

14.3.3 References to a number of days refer to calendar days unless Business Days are specified.

14.3.4 The Parties acknowledge that they and their attorneys have reviewed this Agreement and have had the opportunity to negotiate fully all of its provisions, and that any rule of construction to the effect that any ambiguities are to be resolved against the drafting Party, or any similar rule operating against the drafter of an agreement, shall not be applicable to the construction or interpretation of this Agreement.

14.3.5 Each representation, warranty and covenant set forth herein shall have independent significance.

14.4 Expenses.

Except as otherwise specifically provided in this Agreement, each Party shall be responsible for and shall pay all costs and expenses incurred by that Party in connection with the negotiation and administration of this Agreement, including all fees and expenses of such Parties’ respective representatives, counsel and consultants.

14.5 Amendment and Modification.

This Agreement may be amended, modified or supplemented only by an agreement in writing signed by the Parties.

14.6 Waiver of Compliance; Consents.

Unless otherwise stated, no failure or delay by any Party in exercising any right or privilege under this Agreement operates as a waiver of such right or privilege, and no single or partial exercise of any such right or privilege precludes any other or further exercise of such right or privilege or the exercise of any other right or privilege. Any consent required or permitted by this Agreement is binding only if in writing.

14.7 Notices.

Any notices of (i) initiation of dispute resolution under Section 11 of this Agreement; (ii) termination under Section 12 of this Agreement; (iii) any alleged material breach of this Agreement; and (iv) a change of address for the Persons listed in Section 7.4.4 or this Section 14.7 of this Agreement shall be in writing and shall be (a) delivered by hand, (b) sent electronically by email, with delivery of such transmissions confirmed, or (c) sent certified mail or by a nationally recognized overnight delivery service, charges prepaid, to the address set forth below (or such other address for a Party, as shall subsequently be specified, by like notice):

If to CDWR, to:

California Department of Water Resources
1416 Ninth Street
Sacramento, California 95814
Email: mark.andersen@water.ca.gov
Attn: Mark Andersen

with hard-copy to:

Chief Counsel
California Department of Water Resources
1416 Ninth Street
Sacramento, California 95814

And:

If to NV Energy, to:

NV Energy
Generation Partnership Contracts
6226 W. Sahara Ave.
Las Vegas, Nevada 84146
Mail Station #25
Email: acasey@nvenergy.com
Attn: Ann Casey

with hard-copy to:

NV Energy
General Counsel
6226 W. Sahara Ave. MS03A
Las Vegas, Nevada 84146

Each notice or other communication shall be deemed to have been duly given and to be effective (d) if delivered by hand, immediately upon delivery if delivered on a Business Day during Normal Business Hours and, if otherwise, on the next Business Day, (e) if sent by electronic transmission, immediately upon confirmation that such transmission has been successfully transmitted on a Business Day before or during Normal Business Hours and, if otherwise, on the Business Day following such confirmation or (f) if sent by a nationally recognized overnight delivery service, on the day of delivery by such service or, if not a Business Day, on the first Business Day after delivery. Notices sent via email must be followed by delivery within two Business Days by notice delivered by hand, nationally recognized delivery services, or by United States mail.

14.8 Publicity.

Neither Party shall make any public announcement regarding this Agreement prior to Closing. NV Energy and CDWR shall consult with each other in advance of any public announcements to be made by the Parties regarding this Agreement and will make Commercially Reasonable Efforts to agree to the terms of any public announcement or similar publicity to be made or released by the Parties regarding this Agreement. Public announcements shall not be interpreted to include responses to media inquiries or requests of any Governmental Authority.

14.9 Assignment; No Third-Party Rights.

This Agreement and all of the provisions hereof shall be binding upon and inure to the benefit of the Parties and their respective successors and permitted assigns, but neither this Agreement nor any of the rights, interests or obligations hereunder shall be assigned by any Party without the prior written consent of the other Party; provided that NVE shall have the right to assign its rights hereunder to any of its affiliates without such consent provided that this assignment does not constitute any implied or express abrogation of NVE's obligations under this Agreement. This Agreement and its provisions are for the sole benefit of the Parties to this Agreement and their successors and permitted assigns and shall not give any other Person any legal or equitable right, remedy or claim.

14.10 Waiver of Litigation and Right to Jury Trial.

AS SET FORTH IN SECTION 11, THE PARTIES AGREE THAT ANY AND ALL CONTROVERSIES OR CLAIMS ARISING OUT OF OR RELATING TO THIS AGREEMENT, OR THE BREACH THEREOF, SHALL BE SETTLED BY BINDING ARBITRATION AND EACH PARTY HEREBY WAIVES ANY RIGHT TO TRIAL BY COURT OR JURY OF ANY CLAIM, DEMAND, ACTION, OR CAUSE OF ACTION ARISING UNDER THIS AGREEMENT EXCEPT THAT THE

JUDGMENT ON THE ARBITRATION AWARD MAY BE ENTERED IN ANY COURT HAVING JURISDICTION THEREOF.

14.11 Further Assurances; Records.

Each Party shall cooperate and use Commercially Reasonable Efforts to take such actions, and execute all such further instruments and documents, at or subsequent to the Effective Date of this Agreement, as the other Party may reasonably request in order to effect the transactions contemplated by and consistent with the terms and purposes of this Agreement. NVE shall provide CDWR with access to all relevant documents and other information pertaining to the AOC, including such documents and other information that are needed for the purposes of preparing tax returns, preparing audits or responding to audits or audit requests by any Person or Governmental Authority.

14.12 Severability.

If any provision contained in this Agreement shall for any reason be held invalid, illegal or unenforceable in any respect, such invalidity, illegality or unenforceability shall not affect any other provision of this Agreement, and this Agreement shall be construed as if such invalid, illegal or unenforceable provision had never been contained herein, unless the invalidity of any such provision substantially deprives either Party of the practical benefits intended to be conferred by this Agreement. Notwithstanding the foregoing, any provision of this Agreement held invalid, illegal or unenforceable only in part or degree shall remain in full force and effect to the extent not held invalid or unenforceable, and the determination that any provision of this Agreement is invalid, illegal or unenforceable as applied to particular circumstances shall not affect the application of such provision to circumstances other than those as to which it is held invalid, illegal or unenforceable.

14.13 Counterparts.

This Agreement may be executed in multiple counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. This Agreement may be executed on signature pages exchanged by facsimile or electronic mail, in which event each Party shall promptly deliver to the others such number of original executed copies as the others may reasonably request.

[signature page follows]

IN WITNESS WHEREOF, the Parties have executed this Environmental Agreement as of the date first written above.

NEVADA POWER COMPANY d/b/a NV ENERGY:

By: _____

Name: Kevin Geraghty

Title: ~~Senior~~ Vice President, Energy Supply

CALIFORNIA DEPARTMENT OF WATER RESOURCES:

By: _____

Name: Mark W. Cowin

Title: Director

IN WITNESS WHEREOF, the Parties have executed this Environmental Agreement as of the date first written above.

NEVADA POWER COMPANY d/b/a NV ENERGY:

By:_____

Name: Kevin Geraghty

Title: Senior Vice President, Energy Supply

CALIFORNIA DEPARTMENT OF WATER RESOURCES:

By:_____

Name: Mark W. Cowin

Title: Director

Exhibit A

Cost Allocation Areas

(attached)

EXHIBIT A - COST ALLOCATIONS

AOC Source Area No.	Cost Allocation Area	Unit Allocation			Company Allocation			TOTAL	
		Basis	RG1-3 (NVE)	RG4	Basis	RG4 (NVE)	RG4 (CDWR)	NVE	CDWR
All	Sitewide	Capacity	57.00%	43.00%	Ownership	32.2%	67.8%	70.8%	29.2%
PA-1	Hogan Wash	Exclusive Use	100.0%	0.0%	n/a			100.0%	0.0%
PA-2	Ponds 4B and 4C Area								
	Soils and Solids** Above synthetic liner	MOA 91	100.0%	0.0%	n/a			100.0%	0.0%
	Soils and Solids** Between synthetic liner and groundwater level	Exclusive Use	0.0%	100.0%	MWh: 1983-2000	15.6%	84.4%	15.6%	84.4%
	Groundwater, Soils and Solids** Below groundwater level	Exclusive Use	0.0%	100.0%	MWh: 1983-2000	15.6%	84.4%	15.6%	84.4%
PA-3	Fomer Pond 4A Area								
	Soils and Solids** Above groundwater level	Contributions	16.0%	84.0%	Ownership	32.2%	67.8%	43.0%	57.0%
	Groundwater, Soils and Solids** Below groundwater level	Contributions	42.0%	58.0%	MWh: 1983-1998	16.5%	83.5%	51.6%	48.4%
PA-5, 6, 7	Former Pond D, Pond E, Pond F, Former Pond G								
	Soils and Solids** Above groundwater level	Exclusive Use	100.0%	0.0%	n/a			100.0%	0.0%
	Groundwater, Soils and Solids** Below groundwater level	Exclusive Use	100.0%	0.0%	n/a			100.0%	0.0%
PA-8	Hydrogen Peroxide Tank Release	MOA-91	100.0%	0.0%	n/a			100.0%	0.0%
SA-1	Unit 4 Treated Water Pond	MWh-Yr : 1-3 1988-1996, 4 1983-1996	44.2%	55.8%	MWh: 1983-1996	15.0%	85.0%	52.6%	47.4%
SA-2	Unit 4 Cooling Tower	Exclusive Use	0.0%	100.0%	MWh: 1983-2012*	13.2%	86.8%	13.2%	86.8%
SA-3	Unit 4 Cooling Tower Catch Basin	MWh: 1-4 1983-2012	56.8%	43.2%	MWh: 1983-2012*	13.2%	86.8%	62.5%	37.5%
SA-4	Units 1,2,3 Coal Pile, Unit 4 Coal Pile, and Fly Ash under Unit 4 Coal Pile								
	Units 1,2,3 Coal Pile soils above groundwater level	Exclusive Use	100.0%	0.0%	n/a			100.0%	0.0%
	Units 1,2,3 Coal Pile below groundwater level	Exclusive Use	100.0%	0.0%	n/a			100.0%	0.0%
	Fly Ash Fill under unit 4 coal pile (WMU-12)	Exclusive Use	0.0%	100.0%	Ownership	32.2%	67.8%	32.2%	67.8%
	Unit 4 Coal Pile soils above groundwater level	Exclusive Use	0.0%	100.0%	MWh: 1983-2012*	13.2%	86.8%	13.2%	86.8%
	Unit 4 Coal Pile below groundwater level	Exclusive Use	0.0%	100.0%	MWh: 1983-2012*	13.2%	86.8%	13.2%	86.8%
SA-5/6	Area of Previous Fly Ash Fill (WMU-13 and WMU-14)	Exclusive Use	100.0%	0.0%	n/a			100.0%	0.0%
SA-7	Unit 4 Settling Pond	MWh: 1-4 1983-2012	56.8%	43.2%	MWh: 1983-2012*	13.2%	86.8%	62.5%	37.5%
SA-8	Units 1, 2, 3 Catch Basin	Exclusive Use	100.0%	0.0%	n/a			100.0%	0.0%
SA-17	Reported Previous Waste Disposal Area (WMU-8)	Exclusive Use	100.0%	0.0%	n/a			100.0%	0.0%
SA-19	Unit 4 Absorbers and Units 1,2,3 Scrubbers								
	Units 1,2,3 Scrubber Areas	Exclusive Use	100.0%	0.0%	n/a			100.0%	0.0%
	Unit 4 Absorbers Area	Exclusive Use	0.0%	100.0%	MWh: 1983-2012*	13.2%	86.8%	13.2%	86.8%
SA-9	Units 1 and 2 Emergency Diesel Generator	Exclusive Use	100.0%	0.0%	n/a			100.0%	0.0%
SA-10	Former Units 1,2,3 Lube Oil Rack	Exclusive Use	100.0%	0.0%	n/a			100.0%	0.0%
SA-11	Former Gasoline UST (1000-gallon) and Warehouse 1	Exclusive Use	100.0%	0.0%	n/a			100.0%	0.0%
SA-12	Former Diesel AST (850,000 gallon)	MWh: 1-4 1992-2009	56.9%	43.1%	MWh: 1992-2009	14.5%	85.5%	63.1%	36.9%
SA-13	Former Diesel Fuel Unloading Area	MWh-Yr : 1-4 1965-2009	75.9%	24.1%	MWh: 1983-2009	13.6%	86.4%	79.2%	20.8%
SA-14	Former Underground Product Piping, Petroleum Tanks	Exclusive Use	100.0%	0.0%	n/a			100.0%	0.0%
SA-15	Free Product Recovery System	Exclusive Use	100.0%	0.0%	n/a			100.0%	0.0%
SA-16	Vehicle Maintenance Area	MWh-Yr : 1-4 1973-2012	69.7%	30.3%	MWh 1983-2012	13.2%	86.8%	73.7%	26.3%
MA-1 - MA-9 excl: MA-7	Mesa Area	MWh: 1-4 1965-2012	66.0%	34.0%	MWh: 1983-2012	13.2%	86.8%	70.5%	29.5%
MA-7	Landfill used for industrial and non-industrial Waste (WMU-7)	Exclusive Use	100.0%	0.0%	n/a			100.0%	0.0%
PA-4	Closed Ash Fill area under Landfill Haul Road	Capacity	57.0%	43.0%	Ownership	32.2%	67.8%	70.8%	29.2%
SA-18	ASP 1,2,3; Former Clear Wells, Former Fly Ash Disposal Area	Exclusive Use	100.0%	0.0%	n/a			100.0%	0.0%

Pursuant to Section 1.24, Environmental Costs for any given Cost Allocation Area may include costs associated with soils, solids, and/or groundwater except as specifically noted herein above.

* Company Allocations are subject to revision as set forth in Section 2.4 of the Agreement.

** Solids shall mean operational byproducts, including without limitation; ash, residual from absorbers/scrubbers.

Exhibit B

Administrative Order on Consent, dated February 20, 2008

(attached)

AOC DOCUMENT INCLUDED IN
EXHIBIT JOHNS-DIRECT-2

Exhibit C

Form of EA Payment Escrow Instructions

(attached)

EA PAYMENT ESCROW

LETTER OF ESCROW INSTRUCTIONS

July ___, 2013

[Name of Escrow Agent]
[Address of Escrow Agent]
Attention: [Corporate Trust Services]

Ladies and Gentlemen:

The State of California Department of Water Resources ("CDWR") and Nevada Power Company, a Nevada corporation, doing business as NV Energy ("NVE") transmit this Letter of Escrow Instructions (this "Escrow Agreement") to [Name of Escrow Agent], a [national banking association organized and existing under the laws of the United States of America], acting as escrow agent hereunder (in such capacity, the "Escrow Agent"). Upon [Name of Escrow Agent]'s acceptance of this Escrow Agreement, this Escrow Agreement will be binding upon CDWR, NVE and the Escrow Agent.

CDWR and NVE have heretofore entered into that certain Environmental Agreement, dated as of July 18, 2013 (the "Environmental Agreement"). Capitalized terms not defined herein have the meanings given to such terms in the Environmental Agreement. The escrow account established hereunder constitutes the EA Payment Escrow required to be established under Section 3.1 of the Environmental Agreement.

SECTION 1. ***Creation of EA Payment Escrow Account.*** The Escrow Agent is hereby instructed to create and establish a special and irrevocable escrow account designated as the "EA Payment Escrow" (the "EA Payment Escrow") to be held in the custody of the Escrow Agent in trust pursuant to this Escrow Agreement for the benefit of NVE and CDWR, for the entire term of the Environmental Agreement.

CLOSING OF THE ENVIRONMENTAL AGREEMENT

SECTION 2. ***Deposits to the EA Payment Escrow Prior to Closing.*** Prior to Closing of the Environmental Agreement, CDWR will transfer to the Escrow Agent cash in the total amount of Two Million Seven Hundred Sixty Three Thousand and Six Dollars (**$2,763,006**). Such amount represents the $1,829,582 due under Section 3.2.1 of the Environmental Agreement and the $933,424 due under Section 3.2.2 of the Environmental Agreement.

SECTION 3. ***Notice of Deposits.*** Upon receipt of the entire amount of deposit(s) under Section 2 of this Escrow Agreement, the Escrow Agent shall notify the following persons at the following email addresses:

Linda Ackley	Linda.Ackley@water.ca.gov
Andrew K.Gordon	AKGordon@duanemorris.com
Mark Warden	MWarden@nvenergy.com
Tim Clark	tclark@fabianlaw.com

The notice shall specify the exact amount received from CDWR.

SECTION 4. ***Authorization to Disburse Funds.*** When all other conditions to Closing of the Termination Settlement Agreement, as defined therein, have been met, NVE and CDWR each shall execute and deliver to Escrow Agent an "Authorization to Distribute Funds," in the form attached as Exhibit A.

SECTION 5. ***Disbursements at Closing*.** Upon receipt of the Authorization to Distribute Funds executed by both NVE and CDWR, the Escrow Agent shall, and is hereby irrevocably instructed to, disburse the following amounts from escrow:

(1) To NVE, Two Million Seven Hundred Sixty Three Thousand and Six Dollars ($2,763,006), according to the wire instructions on the Authorization to Distribute Funds.

The Escrow Agent shall provide prompt notice to both parties of the disbursement at the addresses in Section 3.

PAYMENTS MADE IN DISPUTE

SECTION 6. ***Deposits to the EA Payment Escrow As Payments in Dispute*.** From time to time throughout the term of the Environmental Agreement, CDWR may transfer to the Escrow Agent cash amounts for deposit into the EA Payment Escrow. The Escrow Agent shall deposit all of such amounts received from CDWR to the EA Payment Escrow.

SECTION 7. ***Investment of EA Payment Escrow*.** The Escrow Agent shall invest the moneys deposited in the EA Payment Escrow under Section 6 in either (a) a money market mutual fund consisting of obligations issued and/or guaranteed as to principal and interest by the United States Treasury or (b) such other investments as are approved in writing by both CDWR and NVE.

SECTION 8. ***Notice of Deposits*.** Upon receipt of any deposit under Section 6 of this Escrow Agreement, the Escrow Agent shall notify the following persons at the following email addresses:

Linda Ackley	Linda.Ackley@water.ca.gov
Mark Anderson	Mark.Anderson@water.ca.gov
Ann Casey	ACasey@nvenergy.com
Tom Woodworth	TWoodworth@nvenergy.com

By written notice to the Escrow Agent, CDWR and NVE may designate other persons to receive notice by email of deposits.

SECTION 9. ***Disbursements*.** The Escrow Agent shall, and is hereby irrevocably instructed to, use and disburse amounts deposited under Section 6 of this Escrow Agreement as follows: (a) to either NVE or CDWR, in accordance with instructions in the form of Exhibit B hereto executed by an authorized officer of both NVE and CDWR; or (b) in accordance with an award from an arbitration instituted under the Environmental Agreement with respect to any funds in the EA Payment Escrow. The Escrow Agent shall provide prompt notice to both parties of each such disbursement at the addresses in Section 8.

SECTION 10. ***Accounting*.** At the request of either NVE or CDWR, the Escrow Agent shall provide an accounting of the funds held in escrow, which shows the date funds were received, and the interest earned on funds in the EA Payment Escrow.

SECTION 11. ***Liability of Escrow Agent*.**

(a) The Escrow Agent shall have no lien whatsoever on the EA Payment Escrow or moneys on deposit in the EA Payment Escrow for the payment of fees and expenses for services rendered by the Escrow Agent under this Escrow Agreement or otherwise. The fees and expenses of the Escrow Agent shall be paid in equal parts by CDWR and NVE.

(b) The Escrow Agent shall not be liable for the accuracy of the calculations as to the sufficiency of any moneys deposited into the EA Payment Escrow.

(c) The Escrow Agent undertakes to perform only such duties as are expressly set forth in this Escrow Agreement and no implied duties or obligations shall be read into this Escrow Agreement against the Escrow Agent.

(d) The Escrow Agent may conclusively rely, as to the truth of the statements and the correctness of the certifications expressed in any instruction in the form of Exhibit A or Exhibit B, and shall be protected as stated in this Escrow Agreement, in acting, or refraining from acting, upon such written instructions furnished to the Escrow Agent and reasonably believed by the Escrow Agent to have been signed or presented by the proper party, and it need not investigate any fact or matter stated in such instruction.

(e) The Escrow Agent shall not have any liability hereunder except to the extent of its own negligence or willful misconduct. The Escrow Agent is not required to resolve conflicting demands to money or property in its possession under this Escrow Agreement.

(f) The Escrow Agent may consult with counsel of its own choice and the opinion of such counsel shall be full and complete authorization to take or suffer in good faith any action in accordance with such opinion of counsel.

(g) The Escrow Agent shall not be responsible for any of the recitals or representations contained herein or in the Environmental Agreement.

(h) No provision of this Escrow Agreement shall require the Escrow Agent to expend or risk its own funds or otherwise incur any financial liability in the performance or exercise of any of its duties hereunder or in the exercise of its rights or powers.

SECTION 12. ***Records and Reports*****.** The Escrow Agent will keep books of record and account in which correct entries shall be made of all transactions made by it relating to the receipt, disbursement and application of the moneys deposited to the EA Payment Escrow and all proceeds thereof. Such books shall be available for inspection at reasonable hours and under reasonable conditions upon reasonable prior notice by NVE and/or CDWR.

SECTION 13. ***Successor Escrow Agent*****.** Any corporation or association into which the Escrow Agent may be merged or converted or with which it may be consolidated, or any corporation or association resulting from any merger, conversion, consolidation or reorganization to which the Escrow Agent shall be a party or any company to which the Escrow Agent may sell or transfer all or substantially all of its corporate trust business (so long as such company meets the requirements set forth below), shall be the successor Escrow Agent under this Escrow Agreement without the execution or filing of any paper or any other act on the part of the parties hereto, anything herein to the contrary notwithstanding.

The Escrow Agent may resign by notifying NVE and CDWR in writing at least 30 days before the effective date of such resignation. The Parties may remove the Escrow Agent and appoint a successor Escrow Agent by notifying the Escrow Agent in writing. No such resignation or removal shall be effective until a successor Escrow Agent meeting the requirements set forth in the next paragraph has delivered an acceptance to CDWR, NVE and the Escrow Agent of (a) its appointment and (b) the cash held under the terms of this Escrow Agreement. If the Parties do not appoint a successor Escrow Agent, the Escrow Agent may petition any court of competent jurisdiction for the appointment of a successor Escrow Agent, which court may thereupon, after such notice, if any, as it may deem proper and prescribe and as may be required by law, appoint a successor Escrow Agent.

SECTION 14. ***Termination*****.** This Escrow Agreement shall terminate when both Parties notify the Escrow Agent that the Environmental Agreement has terminated, all amounts have been disbursed from the EA Payment Escrow and the Escrow Agent has provided a final account statement to the Parties.

SECTION 15. ***Severability*****.** If any section, paragraph, sentence, clause or provision of this Escrow Agreement shall for any reason be held to be invalid or unenforceable, the invalidity or unenforceability of

such section, paragraph, sentence, clause or provision shall not affect any of the remaining provisions of this Escrow Agreement.

SECTION 16. ***Successors and Assigns*****.** All of the covenants and agreements in this Escrow Agreement contained to be performed by or on behalf of CDWR, NVE or the Escrow Agent shall bind and inure to the benefit of their respective successors and assigns, whether so expressed or not.

SECTION 17. ***Compensation of Escrow Agent*****.** For acting under the Escrow Agreement, the Escrow Agent shall be entitled to payment of fees for its services and reimbursement of reasonable disbursements and advances, counsel fees and other expenses reasonably and necessarily made or incurred by the Escrow Agent in connection with its services under this Escrow Agreement in accordance with the Escrow Agent's fee schedule; provided, however, that such amount shall never be deducted or payable from, or constitute a lien or charge against or upon the EA Payment Escrow.

SECTION 18. ***Headings*****.** Any headings preceding the text of the several Sections hereof, and any table of contents appended to copies hereof, are for convenience of reference only and shall not constitute a part of this Escrow Agreement, nor shall they affect its meaning, construction or effect.

SECTION 19. ***Counterparts*****.** This Escrow Agreement may be executed in any number of counterparts, each of which for all purposes shall be deemed to be one original and all of which shall together constitute but one and the same instrument.

This Escrow Agreement shall become effective upon execution of the acceptance of this Escrow Agreement by the Escrow Agent and shall be valid and enforceable as of the time of such acceptance.

STATE OF CALIFORNIA DEPARTMENT OF WATER RESOURCES	NEVADA POWER COMPANY d/b/a NV ENERGY
By: _____	By: _____
Name: _____	Name: _____
Title: _____	Title: _____

ACCEPTANCE BY [NAME OF ESCROW AGENT]

The undersigned hereby accepts the foregoing
Letter of Escrow Instructions dated
July ___, 2013:

[NAME OF ESCROW AGENT],
as Escrow Agent

By _____
Authorized Officer

Dated July ___, 2013

EXHIBIT A
(EA Payment Escrow)

AUTHORIZATION TO DISBURSE FUNDS

To: [Name of Escrow Agent], as Escrow Agent
under that certain Letter of Escrow Instructions
dated July __, 2013 (the "Escrow Agreement"),
by the State of California Department of Water Resources
("CDWR") and Nevada Power Company d/b/a NV Energy ("NVE")

Pursuant to Section 4(a) of the Escrow Agreement, you are hereby authorized and instructed to disburse the following amount: Two Million Seven Hundred Sixty Three Thousand and Six Dollars ($2,763,006) to NVE, by wire transfer according to the following wire instructions:

Wire Instructions: _____

_____

_____

_____

STATE OF CALIFORNIA DEPARTMENT OF WATER RESOURCES

By: _____

Name: _____

Title: _____

NEVADA POWER COMPANY
d/b/a NV ENERGY

By: _____

Name: _____

Title: _____

EXHIBIT B
(EA Payment Escrow)

JOINT DISBURSEMENT INSTRUCTIONS

To: [Name of Escrow Agent], as Escrow Agent
under that certain Letter of Escrow Instructions
dated July __, 2013 (the "Escrow Agreement"),
by the State of California Department of Water Resources
("CDWR") and Nevada Power Company d/b/a NV Energy ("NVE")

Pursuant to Section 4(b) of the Escrow Agreement, you are hereby instructed to disburse the following amount by wiring it to the following address:

Receiving Party: _____

Amount: $_____

Wire Instructions: _____

_____

_____

_____

1. The amount specified above is to be distributed from the EA Payment Escrow in accordance with the Environmental Agreement, dated as of July 18, 2013, by and between the State of California Department of Water Resources and Nevada Power Company d/b/a NV Energy (the "Environmental Agreement").

2. CDWR and NVE agree that the distribution of the amount specified above resolves any dispute related to the payment of such amount under the Environmental Agreement.

STATE OF CALIFORNIA DEPARTMENT OF WATER RESOURCES	NEVADA POWER COMPANY d/b/a NV ENERGY
By: _____	By: _____
Name: _____	Name: _____
Title: _____	Title: _____

Exhibit D

Form of EA Assurance Escrow Instructions

(attached)

EA ASSURANCE ESCROW

LETTER OF ESCROW INSTRUCTIONS

July __, 2013

[Name of Escrow Agent]
[Address of Escrow Agent]
Attention: [Corporate Trust Services]

Ladies and Gentlemen:

The State of California Department of Water Resources ("CDWR") and Nevada Power Company, a Nevada corporation, doing business as NV Energy ("NVE") transmit this Letter of Escrow Instructions (this "Escrow Agreement") to [Name of Escrow Agent], a [national banking association organized and existing under the laws of the United States of America], acting as escrow agent hereunder (in such capacity, the "Escrow Agent"). Upon [Name of Escrow Agent]'s acceptance of this Escrow Agreement, this Escrow Agreement will be binding upon CDWR, NVE and the Escrow Agent.

CDWR and NVE have heretofore entered into that certain Environmental Agreement, dated as of July 18, 2013 (the "Environmental Agreement"). Capitalized terms not defined herein have the meanings given to such terms in the Environmental Agreement. The escrow account established hereunder constitutes the cash portion of the EA Assurance Escrow required to be established under Section 6.1.1 of the Environmental Agreement.

SECTION 1. ***Creation of EA Assurance Escrow Account*****.** The Escrow Agent is hereby instructed to create and establish a special and irrevocable escrow account designated as the "EA Assurance Escrow" (the "EA Assurance Escrow") to be held in the custody of the Escrow Agent in trust pursuant to this Escrow Agreement for the benefit of NVE and CDWR.

SECTION 2. ***Deposits to the EA Assurance Escrow*****.** Concurrently with the execution and delivery of this Escrow Agreement, CDWR will transfer to the Escrow Agent cash, in an amount determined by CDWR. From time to time, CDWR may transfer to the Escrow Agent additional amounts as required by the Environmental Agreement. The Escrow Agent shall deposit all of such amounts to the EA Assurance Escrow.

SECTION 3. ***Investment of EA Assurance Escrow*****.** The Escrow Agent shall invest the moneys constituting the EA Assurance Escrow in either (a) a money market mutual fund consisting of obligations issued and/or guaranteed as to principal and interest by the United States Treasury or (b) such other investments as are approved in writing by both CDWR and NVE. All earnings from any such investments shall be disbursed to CDWR [upon receipt by the Escrow Agent of written instructions signed by an authorized officer of CDWR].

SECTION 4. ***Use of EA Assurance Escrow*****.** The Escrow Agent shall, and is hereby irrevocably instructed to, use and disburse amounts from the Escrow Deposits solely (a) to NVE in accordance with instructions in the form of Exhibit A hereto executed by an authorized officer of NVE, (b) to CDWR in accordance with instructions in the form of Exhibit B hereto, executed by authorized officers of both NVE and CDWR specifying the Party to whom the disbursement should be made.

SECTION 5. ***Accounting*.** At the request of either NVE or CDWR, the Escrow Agent shall provide an accounting of the funds held in escrow, which shows the date funds were received, and the interest earned on funds in the EA Assurance Escrow.

SECTION 6. ***Liability of Escrow Agent*.**

(a) The Escrow Agent shall have no lien whatsoever on the EA Assurance Escrow or moneys on deposit in the EA Assurance Escrow for the payment of fees and expenses for services rendered by the Escrow Agent under this Escrow Agreement or otherwise. The fees and expenses of the Escrow Agent shall be paid by CDWR.

(b) The Escrow Agent shall not be liable for the accuracy of the calculations as to the sufficiency of any moneys deposited into the EA Assurance Escrow.

(c) The Escrow Agent undertakes to perform only such duties as are expressly set forth in this Escrow Agreement and no implied duties or obligations shall be read into this Escrow Agreement against the Escrow Agent.

(d) The Escrow Agent may conclusively rely, as to the truth of the statements and the correctness of the certifications expressed in any instruction in the form of Exhibit A or Exhibit B, and shall be protected as stated in this Escrow Agreement, in acting, or refraining from acting, upon such written instructions furnished to the Escrow Agent and reasonably believed by the Escrow Agent to have been signed or presented by the proper party, and it need not investigate any fact or matter stated in such instruction.

(e) The Escrow Agent shall not have any liability hereunder except to the extent of its own negligence or willful misconduct. The Escrow Agent is not required to resolve conflicting demands to money or property in its possession under this Escrow Agreement.

(f) The Escrow Agent may consult with counsel of its own choice and the opinion of such counsel shall be full and complete authorization to take or suffer in good faith any action in accordance with such opinion of counsel.

(g) The Escrow Agent shall not be responsible for any of the recitals or representations contained herein or in the Environmental Agreement.

(h) No provision of this Escrow Agreement shall require the Escrow Agent to expend or risk its own funds or otherwise incur any financial liability in the performance or exercise of any of its duties hereunder or in the exercise of its rights or powers.

SECTION 7. ***Records and Reports*.** The Escrow Agent will keep books of record and account in which correct entries shall be made of all transactions made by it relating to the receipt, disbursement and application of the moneys deposited to the EA Assurance Escrow and all proceeds thereof. Such books shall be available for inspection at reasonable hours and under reasonable conditions upon reasonable prior notice by NVE and/or CDWR.

SECTION 8. ***Successor Escrow Agent*.** Any corporation or association into which the Escrow Agent may be merged or converted or with which it may be consolidated, or any corporation or association resulting from any merger, conversion, consolidation or reorganization to which the Escrow Agent shall be a party or any company to which the Escrow Agent may sell or transfer all or substantially all of its corporate trust business (so long as such company meets the requirements set forth below), shall be the successor Escrow Agent under this Escrow Agreement without the execution or filing of any paper or any other act on the part of the parties hereto, anything herein to the contrary notwithstanding.

The Escrow Agent may resign by notifying NVE and CDWR in writing at least 30 days before the effective date of such resignation. The Parties may remove the Escrow Agent and appoint a successor Escrow

Agent by notifying the Escrow Agent in writing. No such resignation or removal shall be effective until a successor Escrow Agent meeting the requirements set forth in the next paragraph has delivered an acceptance to CDWR, NVE and the Escrow Agent of (a) its appointment and (b) the cash held under the terms of this Escrow Agreement. If the Parties do not appoint a successor Escrow Agent, the Escrow Agent may petition any court of competent jurisdiction for the appointment of a successor Escrow Agent, which court may thereupon, after such notice, if any, as it may deem proper and prescribe and as may be required by law, appoint a successor Escrow Agent.

SECTION 9. ***Termination*****.** This Escrow Agreement shall terminate when all amounts have been disbursed from the EA Assurance Escrow, and the Escrow Agent has provided a final account statement to the Parties.

SECTION 10. ***Severability*****.** If any section, paragraph, sentence, clause or provision of this Escrow Agreement shall for any reason be held to be invalid or unenforceable, the invalidity or unenforceability of such section, paragraph, sentence, clause or provision shall not affect any of the remaining provisions of this Escrow Agreement.

SECTION 11. ***Successors and Assigns*****.** All of the covenants and agreements in this Escrow Agreement contained to be performed by or on behalf of CDWR, NVE or the Escrow Agent shall bind and inure to the benefit of their respective successors and assigns, whether so expressed or not.

SECTION 12. ***Compensation of Escrow Agent*****.** For acting under the Escrow Agreement, the Escrow Agent shall be entitled to payment by CDWR of fees for its services and reimbursement of reasonable disbursements and advances, counsel fees and other expenses reasonably and necessarily made or incurred by the Escrow Agent in connection with its services under this Escrow Agreement in accordance with the Escrow Agent's fee schedule, as agreed to with CDWR; provided, however, that such amount shall never be deducted or payable from, or constitute a lien or charge against or upon the EA Assurance Escrow.

SECTION 13. ***Headings*****.** Any headings preceding the text of the several Sections hereof, and any table of contents appended to copies hereof, are for convenience of reference only and shall not constitute a part of this Escrow Agreement, nor shall they affect its meaning, construction or effect.

SECTION 14. ***Counterparts*****.** This Escrow Agreement may be executed in any number of counterparts, each of which for all purposes shall be deemed to be one original and all of which shall together constitute but one and the same instrument.

[*signature page follows*]

This Escrow Agreement shall become effective upon execution of the acceptance of this Escrow Agreement by the Escrow Agent and shall be valid and enforceable as of the time of such acceptance.

STATE OF CALIFORNIA DEPARTMENT OF WATER RESOURCES

By: _____

Name: _____

Title: _____

NEVADA POWER COMPANY
d/b/a NV ENERGY

By: _____

Name: _____

Title: _____

ACCEPTANCE BY [NAME OF ESCROW AGENT]

The undersigned hereby accepts the foregoing
Letter of Escrow Instructions dated
July __, 2013:

[NAME OF ESCROW AGENT],
as Escrow Agent

By _____
Authorized Officer

Dated July __, 2013

[*signature page for EA Assurance Escrow*]

EXHIBIT A
(EA Assurance Escrow)

DISBURSEMENT INSTRUCTIONS OF NVE

To: [Name of Escrow Agent], as Escrow Agent
under that certain Letter of Escrow Instructions
dated July __, 2013 (the "Escrow Agreement"),
by the State of California Department of Water Resources
("CDWR") and Nevada Power Company d/b/a NV Energy ("NVE")

Pursuant to Section 4(a) of the Escrow Agreement and Section 6.1.8 of the Environmental Agreement, you are hereby instructed to disburse the following amount by wiring it to the following address:

$_____

Wire Address:

_____

_____

_____

_____

The undersigned hereby certifies on behalf of NVE as follows:

1. The amount specified above is due and owing to us by CDWR pursuant to the Environmental Agreement, dated as of July 18, 2013, by and between the State of California Department of Water Resources and Nevada Power Company d/b/a NV Energy (the "Environmental Agreement").

2. We have billed CDWR for the amount underlying the demand in accordance with Section ___ of the Environmental Agreement, and CDWR has failed to pay such amount within the time period specified by the applicable section of the Environmental Agreement.

3. We have notified CDWR in writing of our intent to invoke Section 6.1.8 of the Environmental Agreement, which section governs withdrawals from the EA Assurance Escrow.

4. Twenty (20) business days have elapsed since the delivery of such notice and CDWR has not cured its failure to pay.

5. The payment to us of the amount specified herein is in accordance with the Environmental Agreement.

NEVADA POWER COMPANY d/b/a NV ENERGY

By: _____

Name: _____

Title: _____

EXHIBIT B
(EA Assurance Escrow)

JOINT AUTHROIZATION FOR DISBURSEMENT

To: [Name of Escrow Agent], as Escrow Agent
under that certain Letter of Escrow Instructions
dated July __, 2013 (the "Escrow Agreement"),
by the State of California Department of Water Resources
("CDWR") and Nevada Power Company d/b/a NV Energy ("NVE")

Pursuant to Section 4(b) of the Escrow Agreement, you are hereby instructed to disburse the following amount by wiring it to the following address:

$_____

Wire Address:

_____

_____

_____

_____

CDWR certifies that after the foregoing disbursement the sum of the amount remaining available in the EA Assurance Escrow plus the amount of any Letter of Credit provided to NVE pursuant to Section 6 of the Environmental Agreement, dated as of July 18, 2013, by and between the State of California Department of Water Resources and Nevada Power Company d/b/a NV Energy (the "Environmental Agreement") is greater than or equal to the Total Assurance Amount determined in accordance with the Environmental Agreement, and that the foregoing disbursement is otherwise in accordance with the Environmental Agreement.

STATE OF CALIFORNIA DEPARTMENT OF WATER RESOURCES	NEVADA POWER COMPANY d/b/a NV ENERGY
By: _____	By: _____
Name: _____	Name: _____
Title: _____	Title: _____

Exhibit E

Form of Letter of Credit

(attached)

IRREVOCABLE LETTER OF CREDIT
No.[_____]
Dated [_____], 2013

Applicant:

State of California Department of Water Resources in its capacity as Operator of the State Water Resources Development System
Attn: Chief, Division of Fiscal Services
P.O. Box 942836
Sacramento, CA 94236-0001

Amount: $24,000,000
Expiration Date: _____, 2015
Date of Issuance: _____, 2013

Beneficiary:

Nevada Power Company
c/o NV Energy, Inc.
6226 West Sahara Avenue,
Las Vegas, Nevada 89146

To Whom It May Concern:

We hereby establish in your favor, effective immediately, our Irrevocable Letter of Credit no. _____ which is available for payment upon telephone advice of demand to the attention of Standby Letter of Credit Unit at telephone number 813-432-6339 or 813-432-6331 and presentation to us by fax of: (i) your written demand for payment containing the text of Exhibit I and (ii) your certification containing the text of Exhibit II, provided that such fax presentation is received on or before the expiry date on this instrument in accordance with the terms and conditions of this letter of credit, it being understood that any such fax presentation shall be considered the sole operative instrument of drawing, not contingent upon presentation of the original documents with respect thereto.

Funds may be drawn under this Letter of Credit, from time to time, in one or more drawings, in amounts not exceeding in the aggregate the amount specified above.

Upon presentation to us in conformity with the foregoing, we will, without any other delay whatsoever, irrevocably and without reserve or condition issue payment instructions by close of our business on the same day to the Federal Reserve wire transfer system in proper form to transfer to the account at the bank designated by you in the demand, the full amount demanded by you in the same-day funds, provided such presentation is made by 12.00 p.m. New York time. In the event such presentation is made after 12.00 p.m. New York time, we will issue our payment instructions by close of our business on the next succeeding day.

Payment hereunder shall be made regardless of: (a) any written or oral direction, request, notice or other communication now or hereafter received by us from the Applicant or any other person

except you, including without limitation any communication regarding fraud, forgery, lack of authority or other defect not apparent on the face of the documents presented by you, but excluding solely an effective written order issued otherwise than at our instance by a court of competent jurisdiction which order is legally binding upon us and specifically orders us not to make such payment; (b) the solvency, existence or condition, financial or other, of the Applicant or any other person or property from whom or which we may be entitled to reimbursement for such payment; and (c) without limiting clause (b) above, whether we are in receipt of or expect to receive funds or other property as reimbursement in whole or in part for such payment.

The stated amount of this Letter of Credit may be increased or decreased, and the expiration date of this Letter of Credit may be extended, by an amendment to this Letter of Credit in the form of Exhibit III. Any such amendment, except when the amount is increased or expiration date is extended, shall become effective only upon acceptance by your signature on a hard copy amendment.

You shall not be bound by any written or oral agreement of any type between us and the Applicant or any other person relating to this credit, whether now or hereafter existing.

We hereby engage with you that your demand(s) for payment in conformity with the terms of this credit will be duly honored as set forth above. All fees and other costs associated with the issuance of and any drawing(s) against this Letter of Credit shall be for the account of the Applicant. All of the rights of the beneficiary set forth above shall inure to the benefit of your successors by operation of law. In this connection, in the event of a drawing made by a party other than the named beneficiary, such drawing must be accompanied by appropriate documentation proving the succession mentioned in the preceding sentence.

THIS LETTER OF CREDIT IS SUBJECT TO AND GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK, AND, EXCEPT AS OTHERWISE EXPRESSLY STATED HEREIN, TO THE INTERNATIONAL STANDBY PRACTICES, ICC PUBLICATION NO. 590 (THE “ISP98”), AND IN THE EVENT OF ANY CONFLICT, THE LAWS OF THE STATE OF NEW YORK WILL CONTROL, WITHOUT REGARD TO PRINCIPLES OF CONFLICT OF LAWS.

Yours faithfully,

_____
(name of issuing bank)

By _____

Title _____

EXHIBIT I
DEMAND FOR PAYMENT

Re: Irrevocable Letter of Credit

No. _____ Dated _____, _____

JPMORGAN CHASE BANK, N.A.
[INSERT ISSUING BANK ADDRESS]
[INSERT ISSUING BANK MAIL CODE]
[INSERT ISSUING BANK CITY, STATE, ZIP CODE]
ATTN: STANDBY LETTER OF CREDIT UNIT

To [Insert Name/Title]:

Demand is hereby made upon you for payment to us of $_____ by deposit to our account no. _____ at [insert name of bank]. This demand is made under, and is subject to and governed by, your Irrevocable Letter of Credit no. _____ dated _____, 2013 in the amount of $_____ established by you in our favor for the account of the State of California Department of Water Resources, in its capacity as Operator of the State Water Resources Development System, as the Applicant.

DATED: _____, _____.

Nevada Power Company

By _____

Title _____

EXHIBIT II
CERTIFICATION

Re: Irrevocable Letter of Credit

No. _____ Dated _____, _____

JPMORGAN CHASE BANK, N.A.
[INSERT ISSUING BANK ADDRESS]
[INSERT ISSUING BANK MAIL CODE]
[INSERT ISSUING BANK CITY, STATE, ZIP CODE]
ATTN: STANDBY LETTER OF CREDIT UNIT

To [Insert Name/Title]:

Reference is made to your Irrevocable Letter of Credit no. _____, dated _____, 2013 in the amount of $_____ established by you in our favor for the account of the State of California Department of Water Resources, in its capacity as Operator of the State Water Resources Development System, as the Applicant.

We hereby certify to you that:

1. $_____, which is the amount of the demand, is due and owing to us by the Applicant;

2. We have billed the Applicant for the amount of the demand in accordance with the Environmental Agreement, and the Applicant has failed to pay such amount within the time period specified by the applicable section of the Environmental Agreement;

3. We have notified the Applicant in writing of our intent to invoke section 6.1.8 of the Environmental Agreement;

4. Twenty (20) business days have elapsed since the delivery of such notice, and Applicant has not cured; and

5. The payment to us of the amount drawn hereby is in accordance with the Environmental Agreement.

DATED: _____, ____. Nevada Power Company

By _____
Title _____

EXHIBIT III
AMENDMENT

Re: Irrevocable Letter of Credit No. _____
Dated _____, 2013

Beneficiary:

Nevada Power Company
c/o NV Energy, Inc.
6226 West Sahara Avenue,
Las Vegas, Nevada 89146

Applicant:

State of California Department
as Operator of the State Water
Resources Development System
Attn: Chief, Division of Fiscal
P.O. Box 942836
Sacramento, CA 94236-00019

To Whom It May Concern:

The above referenced Irrevocable Letter of Credit is hereby amended as follows: by increasing / decreasing / leaving unchanged *(strike two)* the stated amount by $_____ to a new stated amount of $ _____ or by extending the expiration date to _____ from _____. All other terms and conditions of the Letter of Credit remain unchanged.

To the extent this amendment decreases the stated amount of the Letter of Credit, this amendment is effective only when accepted by the beneficiary, which acceptance may only be valid by a signature of an authorized representative.

Dated: _____

Yours faithfully,

JPMorgan Chase Bank, N.A.

By _____
Title _____

ACCEPTED [Required only for decrease in amount]

Nevada Power Company

By _____
Title _____
Date _____

Exhibit F

Form of Written Notice Under Section 6.1.8

(attached)

4815-8598-7601, v. 14

WRITTEN NOTICE OF AMOUNT OWED

UNDER SECTION 6.1.8 OF ENVIRONMENTAL AGREEMENT

VIA EMAIL AND COURIER

[*** ***INSERT DATE***]

California Department of Water Resources
1416 Ninth Street
Sacramento, California 95814
Email: mark.andersen@water.ca.gov
Attn: Mark Andersen

Chief Counsel
1416 Ninth Street
Sacramento, California 95814

Please be advised that the California Department of Water Resources ("CDWR") is past due on payments owed under that certain Environmental Agreement, dated July 18, 2013 ("Environmental Agreement"), by and between CDWR and Nevada Power Company , a Nevada corporation, doing business as NV Energy ("NVE"). NVE hereby provides written notice under Section 6.1.8 of the Environmental Agreement.

Amount Due: _____[*** ***INSERT***]_____ Dollars ($___[*** ***INSERT***]___)

If CDWR has failed to cure within the period provided under Section 6.1.8 of the Environmental Agreement, NVE shall be entitled to immediately take any remedies available to it, including without limitation drawing upon the Letter of Credit (as defined in the Environmental Agreement) or receiving a distribution form the EA Assurance Escrow (as defined in the Environmental Agreement).

NEVADA POWER COMPANY
d/b/a NV ENERGY

By: _____
Name: _____
Title: _____

[*** ***Note: if the notice provision in Section 14.7 of the Environmental Agreement has been updated under Section 14.7 of the Environmental Agreement, then the addresses on this form should be modified accordingly.***]

EXHIBIT JOHNS-DIRECT-5

Exhibit Johns-Direct-5
Reid Gardner Station Site Closure Elements

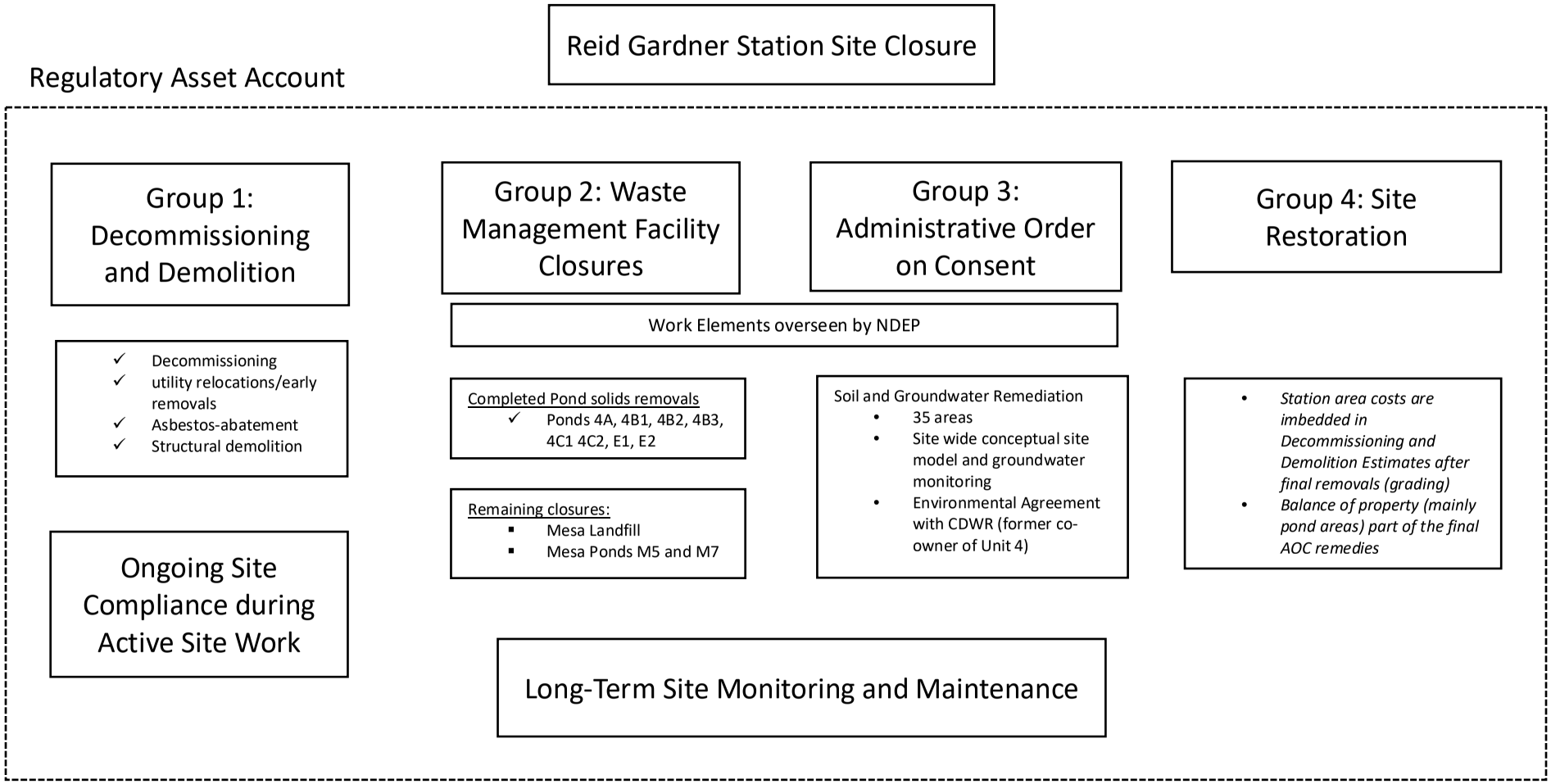


EXHIBIT JOHNS-DIRECT-6

EXHIBIT JOHNS DIRECT-6

REID GARDNER GENERATING STATION
DECOMMISSIONINGS COSTS WITHOUT CARRYING CHARGES
BY PROJECT INCLUDED IN ACCOUNT 182354 REGULATORY ASSET
JUNE 2020 THROUGH DECEMBER 2022 AND FORECASTED COST THROUGH MAY 2023

	(a)	(b)	(c)	(d)	(e)	
Ln No	**Activity Description**	**June - Dec 2020**	**2021**	**2022**	**Total**	Ln
1	**Decommissioning & Demolition**					1
2	RG D&D ASBESTOS-ARO	1,591,855			1,591,855	2
3	RG D&D DECOMMISSIONING	1,530,170	195,481	167,462	1,893,113	3
4	RG D&D ON-GOING COSTS	1,107,051	1,851,301	1,501,003	4,459,354	4
5	Ponds M5&M7 Close and Remove			101,732	101,732	5
6	**SUBTOTAL**	**4,229,076**	**2,046,782**	**1,770,197**	**8,046,054**	6
7	**TOTAL DECOMMISSIONING COSTS THROUGH DECEMBER 2022**	**4,229,076**	**2,046,782**	**1,770,197**	**8,046,054**	7
8						8
9						9
10	**REID GARDNER DECOMMISSIONING COSTS DURING TEST PERIOD, EXCLUDING CARRYING CHARGES**				**8,046,054**	10
11						11
12						12
13						13
14	**FORECASTED COST DURING CERTIFICATION PERIOD (see note 1)**				**803,336**	14
15						15
16						16
17	**TOTAL REID GARDNER DECOMMISSIONING COSTS, EXCLUDING CARRYING CHARGES**				**8,849,391**	17
18						18

Note 1: Forecasted costs ares assumed $0 for asbestos, $46,055 for decommissioning, $720,257 for on-going costs, and $47,024 for Ponds M5 and M7 closure, amounting to $803,336.

EXHIBIT JOHNS-DIRECT-7

EXHIBIT JOHNS DIRECT-7
REID GARDNER GENERATING STATION

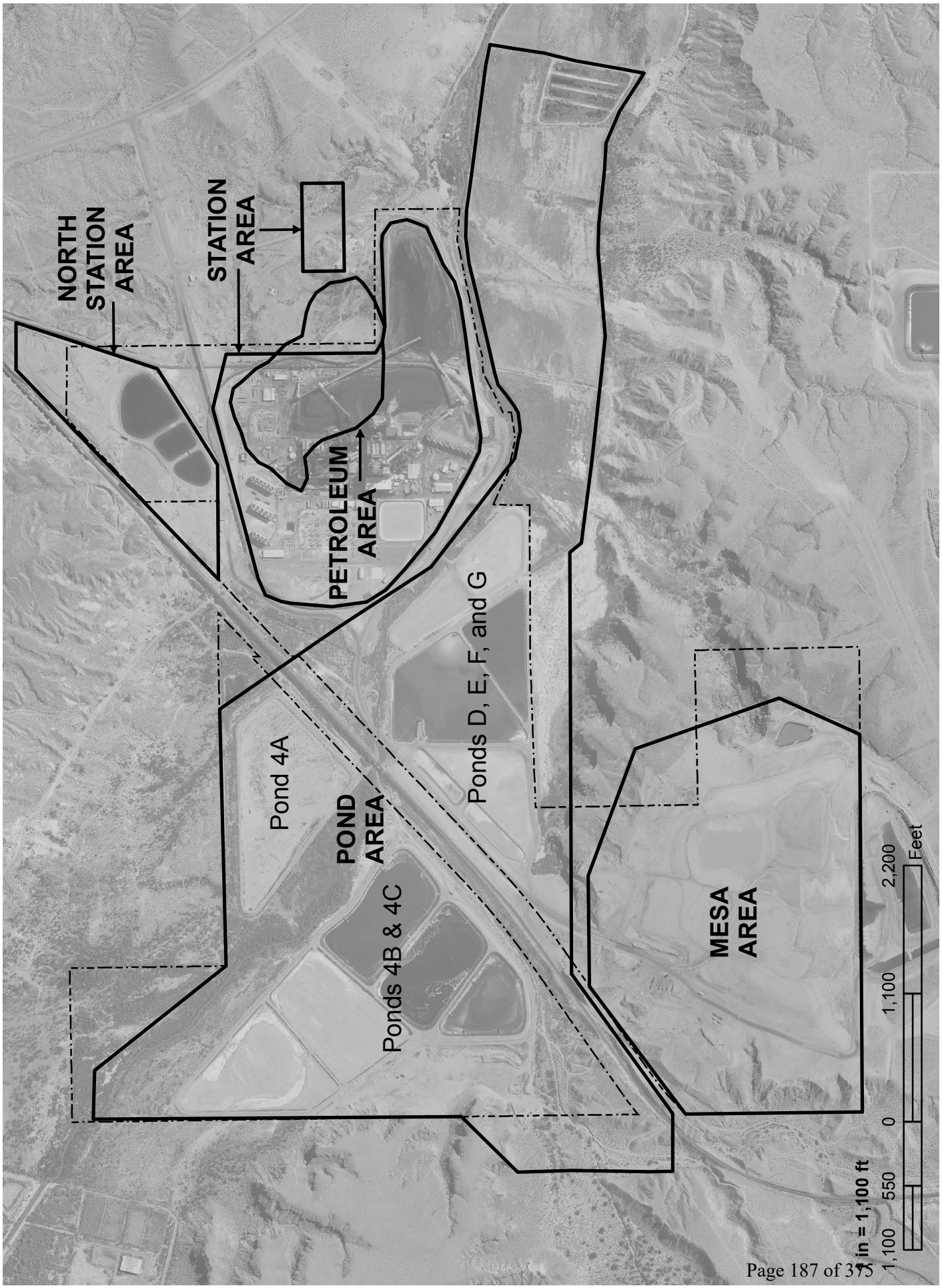
REMEDIATION COSTS WITHOUT CARRYING CHARGES
BY PROJECT INCLUDED IN ACCOUNT 182354 REGULATORY ASSET
JUNE 2020 THROUGH DECEMBER 2022 AND FORECASTED COST THROUGH MAY 2023

Ln No	(a) Project Name	(b) Project	CDWR % Alloc.	(c) Jun 2020 - December 2022 Nevada Power	(d) CDWR	(e) Total	(f) Jan 2023 - May 2023 Forecast Nevada Power	(g) CDWR	(h) Total	Ln No
1	**SITE-WIDE COMMON**									1
2	010900 SITEWIDE PRE-WBS.	9824149501	29.20%							2
3	000100 AOC CDWR EA.	9829058801	0.00%	24,276	-	24,276	$ 900		900	3
4	010100 NVE INTERNAL PM.	9825249001	29.20%	281,286	116,011	397,296	$ 58,016	23,927	81,943	4
5	010200 NVE PROGRAM PM.	9826196501	29.20%	1,135,274	468,220	1,603,494	$ 159,625	65,834	225,459	5
6	010300 TECH CONTRACTOR PM	9825248801	29.20%	491,973	202,904	694,878	$ 69,878	28,820	98,697	6
7	010400 NDEP AGENCY.	9825249101	29.20%	56,222	23,187	79,409	$ 14,160	5,840	20,000	7
8	010500 NDEP CONTRACTOR.	9825249301	29.20%	366,109	150,994	517,103	$ 59,182	24,408	83,590	8
9	010600 GW MONITORING.	9828414901	29.20%	834,307	344,093	1,178,399	$ 196,926	81,218	278,144	9
10	010700 General Documents	9833372801	29.20%	13,503	5,569	19,072	$ 904	373	1,277	10
11	010800 Data/Doc Manage	9833372901	29.20%	92,584	38,184	130,768	$ 20,121	8,299	28,420	11
12	010900 Concept Site Model	9833373001	29.20%	2,672,502	1,102,218	3,774,720	$ 525,073	216,556	741,629	12
13	011000 Background Eval	9833373201	29.20%	82,413	33,990	116,403			-	13
14	011200 MUDDY RIVER EVAL	9834075001	29.20%	35,024	14,445	49,470			-	14
15	011300 CORR ACTION PLAN	9841087101	29.20%	92,411	38,113	130,524	$ 20,691	8,534	29,225	15
16	**SUBTOTAL, COMMON**			**6,177,883**	**2,537,928**	**8,715,812**	**1,125,475**	**463,808**	**1,589,283**	16
17										17
18	**POND SOURCE AREAS**									18
19	020100 PA1 HOGAN WASH	9839371701	0.00%	61,934	-	61,934	-		-	19
20	020202 PA2 PNDS 4B-4C GW	9836293201	84.40%	8,173	44,215	52,388	-		-	20
21	020302 PA3 PONDS 4A GW	9836293301	48.40%	555	521	1,076	4,644	4,356	9,000	21
22	020402 PA5-7 PONDS D-G GW	9836293401	0.00%	109,404	-	109,404	92,500		92,500	22
23	020500 PA8 HYDROGEN TANK	9836292701	0.00%	-	-	-	-		-	23
24	**SUBTOTAL, POND SOURCE AREAS**			**180,066**	**44,736**	**224,802**	**97,144**	**4,356**	**101,500**	24
25										25
26	**POND SOLIDS REMOVALS**									26
27	020201 PNDS B123 SLDS RMV	9838329301	Note a	-	-	-	-	-	-	27
28	020201 POND C1 SOLIDS RMV	9829918201	Note a	-	-	-	-	-	-	28
29	020201 POND C2 SOLIDS RMV	9829918101	Note a	-	-	-	-	-	-	29
30	020301 Pond 4A Solids Rmv	9821795901	57.00%	-	-	-	-	-	-	30
31	020401 POND E1 SOLIDS RMV	9838329401	0.00%	-	-	-	-	-	-	31
32	020401 POND E2 SOLIDS RMV	9834558501	0.00%	-	-	-	-	-	-	32
33	**SUBTOTAL, POND SOLIDS REMOVALS**			**-**	**-**	**-**	-	-	-	33
34										34
35	**STATION SOURCE AREAS**									35
36	030100 SA1 U4TRTD WTR PND	9841348301	47.70%				-		-	36
37	030200 SA2 U4 COOLING TWR	9841348401	Note b				-		-	37
38	030300 SA3 U4 COOLING TO	9844305801	Note b	31,092	17,718	48,810	16,105	9,178	25,283	38
39	030401 SA4 WMU12 FILL	9840085501	67.80%	1,746,931	3,678,322	5,425,253	$ 46,719	98,371	145,091	39
40	030402 SA4 U4 COAL PILE	9840085401	Note b	106	516	622	-		-	40
41	030403 SA4 U1-3 COAL PILE	9836371501	0.00%	4,930,701	-	4,930,701	$ 106,670		106,670	41
42	030500 SA5/6 FLY ASH FILL	9837270601	0.00%	39,854	-	39,854	2,500		2,500	42
43	030600 SA 7 UNIT 4 SETTLI	9844472701	Note b	49,721	28,334	78,055	12,944	7,376	20,320	43
44	030700 SA8 U1-3 CATCH BSN	9837270701	0.00%	-	-	-			-	44
45	030800 SA17 DISPOSAL AREA	9836293101	0.00%	-	-	-			-	45
46	030900 SA19 U4 ABSORBERS	9841348501	Note b	7,442	36,078	43,520	3,516	17,044	20,560	46
47	030900 SA 19 UNIT 1-3 SC	9844306401	0.00%	78,734	-	78,734	15,240		15,240	47
48	030900 SA 19 UNIT 1-3 SCRUBBE	9844306401	0.00%						-	48
49	**SUBTOTAL, STATION SOURCE AREAS**			**6,884,581**	**3,760,968**	**10,645,549**	**203,694**	**131,970**	**335,664**	49
50										50
51	**PETROLEUM SOURCE AREAS**									51
52	040100 SA9 U1-2 EMGNCY DG	9836293501	0.00%	86,021	-	86,021	17,224		17,224	52
53	040200 SA10 U1-3 OIL RACK	9836293701	0.00%	-	-	-	-		-	53
54	040300 SA11 GAS UST1 WH	9836294001	0.00%	-	-	-	-		-	54
55	040400 SA12 DIESEL AST	9836292901	36.90%	-	-	-	-		-	55
56	040500 SA13 DIESEL UA	9836294401	20.80%	526,510	138,275	664,785	16,359	4,296	20,656	56
57	040600 SA14 FREE PRD EVAL	9834075201	0.00%	271,093	-	271,093	6,571		6,571	57
58	040700 SA15 PRODUCT RCVRY	9836294701	0.00%	-	-	-	-		-	58
59	040800 SA16 VEHICLE MA	9836294801	26.30%	-	-	-	-	-	-	59
60	**SUBTOTAL, PETROLEUM SOURCE AREAS**			**883,623**	**138,275**	**1,021,899**	**40,155**	**4,296**	**44,451**	60
61									-	61
62	**MESA SOURCE AREAS**								-	62
63	050100 MA1-9 MESA AREA	9841348601	29.50%	43,687	18,280	61,968			-	63
64	050200 MA7 WMU7	9839650201	0.00%	1,658	-	1,658	-		-	64
65	**SUBTOTAL, MESA SOURCE AREAS**			**45,345**	**18,280**	**63,625**	**-**	**-**	**-**	65
66										66
67	**NORTH STATION SOURCE AREAS**									67
68	060100 SA18 ASP FRMR DSPL	9837270801	0.00%	435,639	-	435,639	3,780		3,780	68
69	**SUBTOTAL, NORTH STATION SOURCE AREAS**			**435,639**	**-**	**435,639**	**3,780**	**-**	**3,780**	69
70										70
71	**Grand Total**			**14,607,138**	**6,500,188**	**21,107,325**	**1,470,249**	**604,430**	**2,074,678**	71
72										72
73										73
74										74
75				**14,607,138**	**REID GARDNER REMEDIATION COSTS DURING TEST PERIOD**					75
76										76
77										77
78										78
79				**1,470,248.56**	**FORECASTED COST DURING CERTIFICATION PERIOD**					79
80										80
81										81
82				**16,077,386**	**TOTAL REID GARDNER REMEDIATION COST, EXCLUDING CARRYING CHARGES**					82

NOTES:
a. Pond Solids removal actions for the B and C Ponds were based on volumetric contribuations and prior agreements as defined in the Environmental Agreement between Nevada Power Company and California Department of Water Resources, July 2013. Final amounts were based on surveyed quantities of solids removed.
b. One-time adjustment (true-up) to the allocation for each source area where made based on the actual duration of Unit 4 operation by Nevada Power after July 2013 as defined in the Environmental Agreement between Nevada Power Company and California Department of Water Resources, July 2013.

EXHIBIT JOHNS-DIRECT-8

Exhibit- Johns-Direct-8



AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, MATHEW JOHNS, 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: June 5, 2023

Mathew Johns

JENNIFER KELLY

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 23-06____
2023 General Rate Case

Prepared Direct Testimony of

Jennifer Kelly

Revenue Requirement

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

A. My name is Jennifer Kelly. I am currently the Project Director of FERC Interconnections. From October 2020 to January 2023, I was the Director of Distribution Design Services ("DDS") for the southern Nevada region of Nevada Power Company d/b/a NV Energy ("Nevada Power" or the "Company"). As the Director of DDS, I worked primarily out of the Company's Beltway Operations Center, which is located at 7155 Lindell Road, Las Vegas, Nevada. I am filing testimony in this proceeding on behalf of the Nevada Power.

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

A. I have a Master of Science Degree in Electrical Engineering, and Master of Business Administration. I have more than 27 years of experience in the utility industry in a variety of positions and I have been in my current position since February of 2023. Additional details regarding my professional background and experience are set forth in **Exhibit Kelly Direct-1.**

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR OF DDS.

A. As Director of DDS, my responsibilities included overseeing the customer service, engineering, and project coordination for distribution line extensions and facility relocation projects subject to Rule 9 and local government franchise agreements. I was responsible for all the business processes and deliverables the DDS department provided for supporting customer projects in southern Nevada including governmental, commercial, residential developers, and individual homeowners, from the application to the execution of the line extension agreement.

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

A. Yes. I provided testimony on behalf of Nevada Power for the Undergrounding Management Plan in Docket No. 22-08018 and for Nevada Power in its general rate application in Docket No. 20-06003.

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

A. I support the investment made by Nevada Power in new line extension facilities pursuant to Rule 9 of Nevada Power's electric tariff. I also describe and support the Company's investment into the New Business Portal project.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibits:

Exhibit Kelly-Direct-1 - Statement of Qualifications

7. Q. PLEASE DESCRIBE THE DDS DEPARTMENT AND ITS RESPONSIBILITIES.

A. As stated in Q&A 3, the DDS department provides customer service, engineering, and project coordination for distribution line extensions and facility relocation projects subject to Rule 9 and local government franchise agreements. DDS endeavors to provide excellent customer service to customers, the development community, local governmental entities and permitting agencies such as the Nevada Department of Transportation ("NDOT"). To facilitate these objectives, members of DDS regularly participate in industry organization meetings and conduct periodic planning meetings with governmental entities such as NDOT.

DDS handles all types of electric residential, commercial and industrial projects. DDS coordinates and prepares all the requirements to provide the requested service including distribution planning, acquisition of governmental permits and land rights, project design, estimation of construction costs, as well as the preparation of the required agreements.

In addition, DDS addresses conflicts between Nevada Power's existing distribution facilities and proposed government infrastructure projects. These projects may require relocation of distribution facilities as required under Rule 9 as well as government franchise agreements.

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8. Q. PLEASE DESCRIBE THE DIFFERENT TYPES OF PROJECTS DDS ADMINISTERS.

A. The projects administered by DDS can be grouped into two major categories:

(1) Line Extensions that Serve Increased Demand.

These projects normally involve new load and result in new distribution facilities or, in some cases, the modification to the existing distribution facilities. Projects in this grouping include custom homes, residential apartments or condominiums, residential subdivisions, small and large commercial developments, master planned communities, and government projects. A line extension for these types of projects may involve standard distribution facilities, but occasionally requires the installation of high voltage distribution ("HVD") facilities and/or a substation. When a project requires HVD or substation facilities, those portions are turned over to the Transmission and Distribution ("T&D") Major Projects group. That group prepares the costs and contracts for the HVD and substation facilities, however, the distribution portion remains with the DDS department. In these cases, separate agreements are prepared, reviewed, and formally executed pursuant to the established chart of signature authority for DDS and the T&D Major Projects department.

Depending on the circumstances, Rule 9 may require the collection from an applicant of a refundable advance and/or a non-refundable contribution in aid of construction ("CIAC") advance. Both types of advances are calculated based on the estimated project cost, net of any allowance granted. An allowance is a credit toward construction costs for new loads and is based on the number of units, meters or kilovolt-ampere ("kVA") load that will be served by the line extension facilities. As the name implies, an "advance subject to refund" may be refunded to the

customer over time, depending on the ultimate load served from the Rule 9 facilities. In cases where separate agreements are required to address HVD and/or substation installations separate from standard distribution line extensions, payment of advances are made separately pursuant to the terms of the respective agreements satisfying total advances due.

(2) Relocation and Modification of Existing Distribution Facilities. These projects involve an alteration of existing distribution facilities, generally, at the request of governmental entities, but occasionally, at the request of a residential or commercial customer. For relocation and modification projects, Rule 9 requires applicants to pay the entire cost through a non-refundable CIAC, with no allowance to the applicant unless the alterations directly contribute to a net increase in demand.

The costs are handled differently if the relocation or modification is requested by a government agency through its franchise agreement with the Company. Pursuant to its franchise agreements with local governments and agency permits (e.g., NDOT), Nevada Power is allowed to install electric facilities in public rights of way with no easement costs. For both Company-initiated and applicant-initiated projects, this is a valuable benefit as it reduces both the project schedule and cost by minimizing the requirements to obtain third-party easements. However, the franchise agreements and permits require that Nevada Power relocate facilities installed in government rights of way if requested by the franchisor or permit issuer, except in situations where Nevada Power holds a pre-existing property right in the right of way. Relocation work must follow the schedules described in the agreements or those dictated by the governmental entity's project timeline. The

costs associated with these relocations are not funded by CIACs and are instead recovered from all customers through general rates.

9. Q. WHAT RULES GOVERN THE COST OF LINE EXTENSION PLANT INVESTMENT?

A. As discussed above, Rule 9 projects that are expected to increase demand are eligible to receive an allowance against construction costs, with the amount dependent on the type of service that will be provided to the new load and the number of units, meters, or amount of new kVA demand that is expected to be served by the project. Some or all of the allowance can be granted before the construction of the project, where there is a reasonable expectation that the supporting number of units, meters and/or kVA demand will be initiated within the 12-month period following the completion of construction of the line extension facilities.

Allowances that are not provided in advance of construction can be received by the applicant after construction in the form of refunds, based on the actual number of units, meters or kVA demand that are initiated between the completion of construction and the expiration of the Rule 9 agreement. The amount of the refund is calculated through the performance of an allowance true-up.

If the estimated cost of the project exceeds the amount of the allowance granted to the applicant before construction, the applicant must advance or pay the difference. There are two types of advances. The advance subject to refund is the amount that the applicant may receive back in the form of refunds based on the number of units, meters or amount of new kVA demand that is served on the project. An advance

not subject to refund is the portion of the project cost that is not eligible for refund and is considered a CIAC. Under Rule 9, certain types of costs are treated as CIAC and may not be offset by the allowance, such as requests for facilities by the Applicant that are in excess of the minimum requirements necessary to serve, modification of facilities with no increase in demand or units, and costs to obtain right of way.

In basic terms, the Company's investment is the amount of the project cost that is not paid for by the applicant through either a CIAC or an advance subject to refund. Stated differently, advances paid by the line extension applicant in the form of either a non-refundable CIAC advance, or as any remaining balance of an advance subject to refund that does not qualify for a refund by the expiration of the Rule 9 agreement, become CIACs and are a permanent offset to plant in service. If a project qualifies for a refund after it is constructed, the amount refunded essentially becomes Nevada Power's utility plant in service.

10. Q. HOW MUCH INVESTMENT IN DDS PROJECTS HAS NEVADA POWER MADE SINCE ITS LAST GENERAL RATE CASE?

A. Nevada Power classifies projects into different budget identification numbers ("IDs") and combines them into programs for tracking and reporting purposes. The budget ID program "D1" tracks distribution line extensions project and substation breaker additions that serve new or increased demand. The budget ID program "D5" tracks projects that involve alterations to existing electric facilities, typically relocations. The total actual and estimated costs of Rule 9 related projects including street and highway less new business expired advances booked to plant in service between June 1, 2020, and May 31, 2023, totaled $251,769,651 shown in **Table**

Kelly-Direct-1. The breakdown per program is provided in **Table Kelly-Direct-2** and **Table Kelly-Direct-3**. The budget descriptions in the tables indicate the project type.

Table Kelly Direct-1

D1 and D5 Expenditure Comparisons

	2020 GRC through May 31, 2020 (in millions)	**2023 GRC through May 31, 2023 (in millions)**
D1 Projects	$160.92	$224.75
D5 Projects	$21.65	$27.02
Total	$182.56	$251.77

Distribution line extensions in the D1 program grew approximately 39.7 percent or $63.83 million, and facility relocation in the D5 program grew approximately 24.8 percent or $5.38 million, totaling approximately 37.9 percent or $69.20 million more than the amounts filed in the 2020 general rate case. This is attributable to the growth experienced in southern Nevada since 2020.

The above-mentioned projects are included in the plant additions provided by Christina Hanshew in Exhibits Hanshew-Direct-2 and Hanshew-Direct-3. Distribution system improvements for transmission and distribution programs that were designed by DDS are included in the plant additions provided by Fatima Bouzidi in her direct testimony.

Table Kelly Direct-2

D1 Program Expenditures

Budget ID	Budget Description	Actuals through December 31, 2022 (in millions)	Estimated through May 31, 2023 (in millions)	Total (in millions)
D1111	Residential - Subdivision	$58.49	$9.59	$68.08
D1113	Residential - Services	$30.26	$5.45	$35.71
D1130	Metering	$24.62	$5.16	$29.78
D1137	Master Planned Feeder	$18.83	$3.24	$22.07
D1104	Commercial - (LGS3) 1000kW +	$16.37	$2.16	$18.53
D1103	Commercial - (LGS1) 11-299kW	$11.26	$2.50	$13.76
D1101	Commercial - (LGS2) 300-999kW	$10.71	$2.13	$12.84
D1109	Multi Family - Townhomes	$8.18	$1.95	$10.13
D1105	Multi Family - Apartments	$7.14	$1.65	$8.79
D1106	Residential - Custom	$2.24	$0.29	$2.53
D1108	Multi Family - Condos	$2.13	$0.26	$2.39
D1126	Large Projects Non Core	$1.99	$0.20	$2.19
D1193	Mixed Use - Core	$0.93	$0.20	$1.13
D1192	Mixed-Use Large Prj - Non-Core	$1.02	$0.01	$1.02
D1100	Commercial - (GS) 0-10kW	$0.75	$0.08	$0.83
D1110	Residential - Mobile Homes	$0.49	$0.01	$0.50
D1128	Government Rule 9	$0.38	$0.02	$0.39
DSA1D	Distribution circuit breakers	$0.14	$0.17	$0.31
D1133	Commercial Services	($0.02)	$0.30	$0.28
D1136	Temporary Services	$0.03	$0.00	$0.02
D1135	Conduit Design Only Projects	$0.00	$0.00	$0.00
D1131	Advances & Refunds - Core	($5.20)	($1.35)	($6.55)
	D1 Program Total	**$190.74**	**$34.01**	**$224.75**

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Table Kelly Direct-3

D5 Program Expenditures

Budget ID	Budget Description	Actuals through December 31, 2022 (in millions)	Estimated through May 31, 2023 (in millions)	Total (in millions)
D5105	Government Request	$16.82	$3.92	$20.74
D5201	Undergrounding Management Plan	$1.40	$2.37	$3.78
D5108	Other Requests - Non-Revenue	$1.49	$0.27	$1.76
D5131	American Disability Act- LV	$0.57	$0.00	$0.58
D5178	American Disability Act- Hend	$0.00	$0.07	$0.07
D5132	American Disability Act- N. LV	$0.00	$0.06	$0.06
D5101	Commercial Request - Reliability	$0.05	$0.00	$0.05
	D5 Program Total	**$20.33**	**$6.69**	**$27.02**

11. Q. PLEASE BREAK OUT THE TOTAL DDS INVESTMENT INTO ITS DIFFERENT PROJECT TYPES.

A. D1 projects include distribution line extensions that serve new or increased demand, for example line extensions to residential projects, commercial/industrial projects, master planned communities and new construction government projects such as new community centers and parks. Through the end of the test period, December 31, 2022, Nevada Power completed 2,046 projects in the D1 program at a total cost of $190,736,391 (with AFUDC).

There were 16 projects with expenditures greater than $1 million (rounded up): (1) Blanket Work Orders ("BWO") Smart Meters ($13,540,903); (2) BWO 2021 Service Blanket ($10,211,511); (3) BWO 2022 Service Blanket ($10,130,601); (4) BWO 2020 Service Blanket ($9,953,943); (5) BWO Net Meters 2022-South ($3,184,312); (6) BWO Net Meters 2021-South ($3,136,619); (7) BWO Net Meters

2020-South ($3,013,711); (8) BWO METERS ($1,650,739); (9) INSPIRADA ADDENDUM 6 ($1,558,124); (10) MSG LAS VEGAS VENUE AT VENETIAN – PHASE 2 ($1,461,007); (11) BLM 270 ADDENDUM 3 ($1,358,267); (12) UNION VILLAGE ADDENDUM 2 ($1,338,324); (13) RAINBOW CANYON AREA 1 - ADDENDUM 4 ($1,302,742); (14) MSG LAS VEGAS VENUE AT VENETIAN ($1,112,546); (15) VALLEY VISTA - ADDENDUM 2 ($1,004,277); (16) TROPICAL INDUSTRIAL PARK ($959,186). Estimated expenditures for the D1 program for the period January 1, 2023, through May 31, 2023, are an additional $34,010,051, totaling $224,746,442.

D5 projects include alterations to existing electric facilities, typically relocations. These projects are usually performed at the request of government entities pursuant to Rule 9, franchise agreements or revocable permits. Through the end of the test period, December 31, 2022, Nevada Power completed 123 projects in the D5 program at a total cost of $20,332,601 (with AFUDC).

There were eight projects with expenditures greater than $1 million (rounded up): (1) CLV- LAS VEGAS BLVD. PH. 1 (STEWART TO SAHARA) ($2,531,948); (2) CNLV-GOWAN OUTFALL-ALEXANDER (DECATUR TO SIMMONS) ($1,963,795); (3) CC-215 NORTHERN BELTWAY (N. 5TH TO UPRR) ($1,559,739); (4) CC-DESERT INN (NELLIS TO HOLLYWOOD) R054G16 ($1,514,080); (5) CC- RUSSELL RD IMPROV. (CIMARRON TO RAINBOW) ($1,315,501); (6) CC- JONES BLVD PH. 2 (ERIE TO PYLE) R033R16 ($1,205,941); (7) CC-SILVERADO RANCH IMPROV. (JONES TO VALLEY VIEW) ($1,022,813); (8) CC- FORT APACHE IMPROV. L2178 (ALEXANDER TO CC-215) ($989,946). It is estimated that through the end of the certification

period, Nevada Power will invest an additional $6,690,608 in D5 projects, totaling $27,023,209.

12. Q. SOME OF THE PROJECTS IN THE D1 PROGRAM LISTED ABOVE AND IN EXHIBIT KELLY-DIRECT-2 LISTS "BWO" PLANT ADDITIONS. PLEASE BRIEFLY DESCRIBE THESE PLANT ADDITIONS.

A. Blanket work orders (referred to as "BWO") are established to capture costs of routine or recurring type work (e.g., setting meters) for a specified amount of time (most frequently, annually). Setting up specific work orders for routine type work such as meter sets is not economical or a benefit to the Company and would create an enormous administrative burden to oversee. The blanket work orders are closed to plant in service each month for the work that was completed for that period.

Since the timing of services and meters for specific projects, especially those that have multiple services and meters, can extend over a significant period of time after the completion and energization of the plant additions (primary cable/conductor, poles, fuse cabinets and transformers) that provide capacity to the development, blanket work orders provide a mechanism for capturing these recurring costs over an extended period without delaying the close out and unitization of the other plant additions.

There are two sets of distribution plant additions that are captured through blanket work orders: service wire and meters. Previously, several blanket work orders existed for services, but in 2019, those blanket work orders were consolidated into a single blanket work order to provide a simplified approach to capturing charges in this category from year to year. Meter blanket work orders are separated into

two categories to distinguish from charges associated with net metering installations. The breakdown is provided in **Table Kelly-Direct-4**.

Table Kelly-Direct-4

Blanket Work Orders: Service Wire and Meters

Budget ID or Work Order Number	Budget Description	Actuals through December 31, 2022 (in millions)	Estimated through May 31, 2023 (in millions)	Total (in millions)
D1113	**Residential - Services**	**$30.26**	**$5.45**	**$35.71**
0020000122	BWO 2022 Service Blanket	$10.13	$0.59	$10.72
0020000121	BWO 2021 Service Blanket	$10.21	$0.00	$10.21
0020000120	BWO 2020 Service Blanket	$9.95	$0.00	$9.95
Multiple	Residential - Services	($0.02)	$3.37	$3.35
0020000123	BWO 2023 Service Blanket	$0.00	$1.49	$1.49
0020000119	BWO 2019 Service Blanket	($0.02)	$0.00	($0.02)
D1130	**Metering**	**$24.62**	**$5.16**	**$29.78**
0000080020	BWO Smart Meters	$13.54	$1.06	$14.61
Multiple	Metering	$0.00	$3.59	$3.59
0010011714	BWO Net Meters 2022-South	$3.18	$0.10	$3.29
0010011047	BWO Net Meters 2021-South	$3.14	$0.00	$3.14
0010010306	BWO Net Meters 2020-South	$3.01	$0.00	$3.01
0000080002	BWO METERS	$1.65	$0.03	$1.68
0010012774	BWO Net Meters 2023-South	$0.00	$0.37	$0.37
0010011981	BWO Non-AMI Meters 2022	$0.11	$0.00	$0.11
0010009113	BWO Net Meters 2019-South	($0.01)	$0.00	($0.01)

THE NEW BUSINESS PORTAL PROJECT

13. Q. PLEASE DESCRIBE THE NEW BUSINESS PORTAL PROJECT.

A. The purpose of New Business Portal is to improve the customer experience for new business customers. This project created a New Business web site and mobile application for residential, commercial, and governmental new business customers. Phase 1 and 2 of the New Business Portal improved the customer experience for

southern Nevada residential home builders by creating a New Business web site and mobile application. The result improved the New Business customer experience and enabled the Company to streamline its new service connection operations, customer communications, and service transparency through the implementation of online website and mobile application services within each phase of the New Business utility lifecycle. Phases 1 and 2 went into service in May 2020, and were included in the 2020 Nevada Power general rate case. Phase 3 of this project is the expansion of the New Business Portal for government public works and commercial projects, enabling these customer segments to utilize the on-line customer experience. Phase 3 had a total project cost of $2,262,640 and went into service in February 2021.

14. Q. WHAT TECHNOLOGY PLATFORMS ARE ASSOCIATED WITH THE PROJECT?

A. The New Business Portal includes the applications, infrastructure, and security necessary to implement a new, responsive new business customer portal and mobile application.

15. Q. WHY WAS THE PROJECT NECESSARY?

A. Customer preferences are continually changing, and customers are increasingly interacting with service providers, including utilities, through digital channels. The development and maintenance of web and mobile platforms to communicate with customers and deliver self-service options is expected by customers.

Some of the features of the New Business Portal include project status and visibility at every stage of their project from application, through design, inspection,

construction, and meter set across many succinct dashboards. Customers are also able to directly upload their civil AutoCAD files rather than submitting a flash drive or CD, since the files are usually too large to email. The portal has the ability for customers to pay their contract online, in addition to by check or an ACH electronic transfer of funds. Customers can also request inspections and meter sets online and receive a myriad of push notifications for important updates. As of January 2023, 94 percent of all new project submittals are received through this self-service portal.

16. Q. WHAT WAS THE TOTAL COST OF THIS PROJECT?

A. The total cost of Phase 3 of the New Business Portal through December 31, 2022, was $2,262,640 (with AFUDC.) Additional details regarding the costs of the project are set forth in **Table Kelly-Direct-5** below.

Table Kelly-Direct-5

Cost Category		Costs	% of total
Internal Labor (RT 10, 11, 12)	$	232,577	10%
External Services (RT40, 75, 70)	$	1,709,709	75%
Breakdown of External Services:			
Zilker Technology LLC / Ernst & Young	$	1,673,483	98%
Cognizant Worldwide Limited	$	33,807	2%
Optiv Security Inc.	$	(15,173)	-1%
Twilio Inc.	$	17,637	1%
Verizon Wireless	$	(44)	0%
Prior Period Transfer (RT97)	$	136,236	6%
Materials (RT50, 51)	$	2,115	0%
Internal Overheads (RT30, 31, 32, 33, 52, 53)	$	196,914	9%
AFUDC (RT80)	$	14,912	
Total	**$**	**2,262,640**	**100%**

17. Q. DESCRIBE THE TYPE OF COSTS INCLUDED IN INTERNAL LABOR, EXTERNAL SERVICES, AND MATERIALS.

A. Internal labor includes direct (wages) and indirect (labor overheads) associated with labor provided by Company employees. Internal labor costs are comprised primarily of charges from Information Technology and Energy Delivery business units. The two organizations worked collaboratively on project planning, design, implementation, project management, and testing. Resources from Information Technology were also involved in application development and security testing.

The external services cost category primarily includes vendor-provided professional services including the design, build, test and deployment related costs. **Table Kelly Direct-5** identifies the professional service vendors making up 75 percent of the total project costs.

18. Q. WERE THE EXTERNAL SERVICE PROVIDERS SELECTED THROUGH A COMPETITIVE PROCESS?

A. The external service providers, Zilker Technology LLC/Ernst & Young, Cognizant Worldwide Limited, Optiv Security Testing, and Twilio Inc. were selected through a competitive selection process. Contracts were awarded based on technical capabilities and pricing.

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

A. Yes.

EXHIBIT KELLY-DIRECT-1

JENNIFER A. KELLY

NV Energy
6226 W. Sahara Avenue
Las Vegas, NV, 89142
(702) 402-6855

Ms. Kelly joined the Company twenty-three years ago as a substation engineer, and has since led projects and project management teams to install smart meter, transmission, distribution and generation projects. Current responsibilities as Project Director for FREC Interconnections include working with internal teams to develop the scope and estimates for large scale renewable projects in northern and southern Nevada. Prior to joining the Company, Ms. Kelly worked as a substation engineer at Central Hudson Gas and Electric in Poughkeepsie, New York. She has a master's degree in electrical engineering from Clarkson University in Potsdam, New York, and a master's in business administration from the University of Nevada, Las Vegas.

PROFESSIONAL EXPERIENCE

January 2023 – present **NV Energy**, Las Vegas, NV. *Project Director, FERC Interconnections*
Provide leadership and support throughout the FERC interconnection application process, working with internal teams (transmission planning, project management and engineering) to scope and estimate interconnection requests for large scale renewable projects in northern and southern Nevada.

Oct 2020 – January 2023 **NV Energy**, Las Vegas, NV. *Director, Distribution Design Services-South*
Leading five teams totaling 104 management, contract and bargaining unit employees within the Electric Delivery Distribution Design organization. The teams are responsible for the customer coordination, design, permitting and project management for all new customer electric service projects (~$77m annual), and all government public works projects for the relocation of existing electric facilities (~$15m annual). Leading 20 process improvement teams to execute multiple efficiencies that will reduce throughput and improve the customer experience across all Electric Delivery (from application through meter set). Analyzed workflow, volumetric and resource requirements for entire Electric Delivery organization to support new business and public works project growth (from application through meter set).

Dec 2018 – Oct 2020 **NV Energy**, Las Vegas, NV. *Director, Delivery Optimization-South*
Led five teams totaling 46 management, contract and bargaining unit employees within the Electric Delivery Distribution Operations organization: 1. Capital Maintenance team, responsible for electric infrastructure replacement and reliability projects (~$80m annual). 2. Inspection team, responsible for ensuring consistency with the installation of all electrical and underground standards. 3. Coordination team, responsible for coordination of construction make-ready activities, including permitting, material ordering, survey and outage coordination. 4. Contract Administration team, responsible for all post-procurement activities, contract amendments, invoicing, change orders, contract modifications, and vendor performance management. 5. Work Planning team, responsible for construction scheduling, workload forecasting, metrics and tracking.

Jan 2017 – Dec 2018 **NV Energy**, Las Vegas, NV. *Director, Strategic Projects.*
Led teams within the Strategic Repositioning group to develop and execute several corporate process improvement and cost reduction projects. Also project director for the 'NO on 3' ballot initiative team, managing five workstreams, as well as personally responsible to the Outreach workstream responsible for event coordination, volunteers staffing, volunteer training and community outreach for events.

Oct 2014 – Dec 2016 **NV Energy**, Las Vegas, NV. *Manager, Capital Execution, Generation Engineering.*
Managed special IT project for the $8.2m Project Portfolio Management (PPM) Solution, which integrated SharePoint, Primavera P6 scheduling software and MicroStrategy reporting software to initiate, plan, schedule, execute and close-out capital projects across corporate disparate business units. The PPM Solution was systematically implemented across the entire company and currently manages ~$880m in capital projects annually. Project published in several industry magazines & presented at several industry conferences.

Aug 2012 – Dec 2014 **NV Energy**, Las Vegas, NV. *Manager, Capital Execution, Generation Engineering.*
Managed Generation Project Management Office - project management, project controls and contract administration groups. Team consisted of 10 project managers, 4 project controls consultants and 1 contract admin, responsible for all aspects of capital projects across NV Energy's fleet of twelve (12) generating plants, including coal-fired and gas-fired units (~$135m annual budget).

Jan 2010 – Aug 2012 **NV Energy**, Las Vegas, NV. *Manager, NV Energize.*
Managed the installation of telecommunications infrastructure for the corporate smart grid project, to convert 1.45 million electric & gas meters to wireless meters. Managed the installation of 144 telecommunications sites across Nevada, including contract negotiation/administration, siting, permitting, environmental, design, and coordination of internal and contractor workforce (~$20m or $303m project budget).

Oct 2006 – Jan 2010 **NV Energy (fka Nevada Power Company)**, Las Vegas, NV. *Manager, Major Projects-Resort Corridor.*
Managed a team of 4 senior project managers, responsible for all aspects of utility infrastructure projects within the Las Vegas "Strip" and Downtown metropolitan areas. Team responsible for $85m (49%) in 2008 and $54m (67%) in 2009 annual budgets, for only 0.64% of the LV Valley geography.

Jan 2007 – Jan 2010 Simultaneously personally responsible for the Sinatra Project: managed a 15 member core team to permit/design/construct the $104.5m utility infrastructure required for $9B CityCenter resort with complex cost sharing and pre-approved regulatory structure. Sinatra Project scope included 2 miles of overhead & underground 230kV transmission, 1 mile of underground 138kV transmission, a 230/138/12kV NPC-owned GIS substation & 138/12kV CityCenter-owned substation, and several adjacent substation modifications. Project budget was $104.5m over a 3-year window. Published in T&D World July & August 2009 (August issue was also the cover), and in PowerGrid International in November 2009. Also led committees to support the corporate Diversity efforts and facilitated diversity events and led Franklin Covey 4 Disciplines of Execution, Recruiting & Employee Engagement Wildly Important Goals Teams.

April 2004 – Oct 2006 **Nevada Power Company**, Las Vegas, NV. *Senior Project Manager - Project Services.*
Responsible for all aspects of project management, including leading teams of multi-discipline functional groups to execute utility projects to achieve scope, schedule & budget. Project aspects included:

- Routing & siting, permitting, environmental, design, procurement construction and commissioning
- Scope & contract negotiation with large developers, utilities and governmental entities
- Leading teams with members from T&D Planning, Lands right-of-way & permitting, Legal, Substation, Transmission, Civil, Telecommunication, Environmental, Operations & Distribution
- Budget estimate review, project budget presentation and scope justification to procure funding
- Project scheduling utilizing Primavera Project Planner (P3) software;
- Monthly expenditure tracking, status and variance reporting.

Managed large 230kV resource plan infrastructure projects, the telecommunication stand-alone program, and all customer-driven multi-disciplined transmission relocation projects. Annual budget responsibility: 2004-$6.1m, 2005-$14.1m, 2006-$10.2m, 2007-$42.7m, 2008-$67.9m; Largest number of projects managed: 140 individual projects within a 4-year window.

Aug 2000 – April 2004 **Nevada Power Company**, Las Vegas, NV. *Senior Engineer - Substation Engineering.*
Completed physical and electrical designs of several substation projects, including:

- Two new 138/12kV Substations
- One new 230/138kV Substation
- Two 230kV Switchyard Additions
- 138/12kV Transformer Bank Addition
- Two 138kV Transmission Capacitor Banks
- Several 12kV Feeder Installations

Project responsibilities included project estimating, budget funding and justification, project status reporting; equipment specification, bid evaluation, equipment procurement, all substation physical design drawings, bills of materials, all relay, control and RTU design (schematic) drawings, all wiring drawings, and field installation assistance. Other responsibilities included training a new engineer; Creating, updating and maintaining substation design standards; Traveled to transformer manufacturer's facility in Portugal twice for design review and approved impulse testing of eight 138/12kV 33MVA units.

June 1995 – Aug 2000 **Central Hudson Gas & Electric Corporation**, Poughkeepsie, NY.
Assistant Engineer - Electric Substation Design.
Designed all aspects of several substation projects, including two new 115/13.8kV substations, relay and control upgrade projects, transformer cooling, circuit breaker replacement, and mobile and new transformer installations. Also justified and implemented a department computer network and automated several design calculation standards using spreadsheets.

June 1993 - May 1995 **Dr. S. Ahmed-Zaid, Clarkson University**, Potsdam, NY. *Research Assistant*.
Co-researcher for EPRI Report *"Modeling of Single-Phase Induction Motor Loads in Power System Studies.*" Six-week internship under Carson Taylor at the Bonneville Power Administration in Portland, OR. Utilized EPRI's PSAPAC programs to simulate power systems with a variety of single-phase induction motor loading schemes. Modified EPRI's ETMSP V.3.1 software for single-phase induction motor load modeling.

EDUCATION

University of Nevada, Las Vegas (UNLV), Las Vegas, NV.
Master of Business Administration - December 2018, 3.88/4.00

Clarkson University, Potsdam, NY.
Master of Science, Electrical Engineering - *Power Engineering concentration,* May 1995, 4.00/4.00
Thesis: Effects of Single-Phase Induction Motor Loads on Power System Dynamic Performance.

Clarkson University, Potsdam, NY.
Bachelor of Science, Electrical Engineering - *Power Engineering concentration,* May 1993, 3.60/4.00

Rochester Institute of Technology, Rochester, NY. Electrical Engineering. Attended Sept 88 to Aug 91.

Niagara County Community College, Sanborn, NY.
Associate in Applied Science, Electrical Engineering Technology, May 1988, 3.33/4.00

Trott Vocational High School, Niagara Falls, NY.
Three Years of Electrical Shop, Graduated 6th of 141 students, June 1986, 3.89/4.00

PUBLICATIONS

- Jennifer Kelly, Vincent Veilleux, Joshua Schonbrun, David Graham & Pankaj Sanghi, *"NV Energy's Implementation of Oracle's Primavera P6 EPPM for Capital Program Management,*" Oracle's OpenWorld conference, September 2016.
- Also presented PPM above at the Western Utilities Conference and the RMEL (Rocky Mountain Electric League) conference in 2017.
- Amy Fischbach, *"NV Energy Meets Growing Power Needs of Las Vegas,"* Transmission & Distribution World, July 2009, Vol. 61, No. 7.
- Jennifer Kelly, *"Successful Vegas Project Represents Innovation, Dedication*," Power Grid International, November 2009, Vol. 14.11.
- Jennifer Kelly & Jay Keeling, *"More Power to Las Vegas,"* Transmission & Distribution World, August 2009, Vol. 61, No. 8, including cover.
- S. Ahmed-Zaid, J. A. Kelly, and S. S. Jang, *"Modeling of Single-Phase Induction Motor Loads in Power System Studies,"* EPRI Report TR-105341, Research Project 2447-06, Final Report, Prepared by Clarkson University, January 1996.

PROFESSIONAL LICENSE:

Professional Engineer, New York State, 2000, License No. 077862-1 (not active).

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, JENNIFER KELLY, 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: June 5, 2023

Jennifer Kelly

Jennifer Kelly

JOSH LANGDON

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 23-06___
2023 General Rate Case

Prepared Direct Testimony of

Josh Langdon

Revenue Requirement

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

A. My name is Josh Langdon. My current position is Vice President, Transmission for Nevada Power Company d/b/a NV Energy ("Nevada Power" or the "Company") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies"). My business address is 7155 S. Lindell Rd, Las Vegas, Nevada. I am filing testimony on behalf of Nevada Power.

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

A. I have been employed by the Companies for 15 years. I hold a Bachelor of Science degree in Electrical Engineering and a Master of Business Administration degree from the University of Nevada, Las Vegas. I am also a licensed Professional Engineer in the State of Nevada. I joined the Companies in 2008 as an Engineer in Energy Supply. Since that time, I have held several positions in the Companies, including Power Generation engineering positions and various Generation Operations and Maintenance roles prior to increasing leadership responsibility within the Energy Supply team as a Plant Director. In 2019, I transferred to Energy

Delivery as the Transmission Director of Grid Reliability and System Operations. Within this role, I was responsible for the Companies' Balancing Authority, Transmission and Distribution operating functions. In 2020, I was selected for my current role as Vice President of Transmission, where I am responsible for real time operations for the Companies' Balancing Authority area, substations, and telecommunication system operations. My statement of qualifications is attached as **Exhibit Langdon-Direct-1**.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS THE VICE PRESIDENT OF TRANSMISSION.

A. As the Vice President of Transmission my primary responsibilities include ensuring safe, compliant, and reliable real-time operation of the Company's telecommunication, substation, transmission, and distribution systems.

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

A. Yes. Most recently, I provided testimony in support of the application of the Companies to merge into a single corporate entity, Docket No. 22-03028. I have also recently provided testimony in the first amendment to the 2020 Natural Disaster Protection Plan, Docket No. 21-03040.

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

A. I support the reasonableness and prudence of the Company's project investments in critical substation physical security ballistic shield additions, which are included as expected changes in circumstances ("ECIC") projects for Nevada Power's revenue requirement calculation. For the test period through December 31, 2022,

and the certification period of January 1, 2023, through May 31, 2023, those project investments plant in service are $0. The ECIC estimates are identified in **Table Langdon-Direct-1** below. The ECIC period is June 1, 2023, through December 31, 2023, and estimates will be updated to reflect actual costs once the projects are completed.

Table 1 Langdon-Direct-1

Substation	Transformers Protected	Voltage Classes	Total Est. ECIC Cost
[redacted]	6	4 - 500/230 kV 2 – 500 kV Phase shifters	$22.77M
[redacted]	8	4 – 500/230 kV 2 – 345/230 kV 2 – 345 kV Phase shifters	$8.9M
Total	**14**		**$31.67M**

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibits:

Exhibit Langdon-Direct-1 Statement of Qualifications

NEVADA POWER EXPECTED CHANGES IN CIRCUMSTANCE PROJECTS

7. Q. PLEASE DESCRIBE THE PROJECTS.

A. These projects provides for the acquisition, engineering, and installation of multi-sided critical transformer ballistic protective shields for 14 transformers located at two critical substations in Nevada Power's service territory.

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8. Q. WHAT ARE BALLISTIC SHIELDS AND HOW ARE THEY MORE EFFECTIVE THAN OTHER POTENTIAL ALTERNATIVES?

A. Ballistic shields are specifically designed to block line of sight ballistic attacks on transformers. These ballistic resistant solutions for utilities' critical equipment are installed near the energized equipment. The 30-foot-tall non-conductive fiberglass panels provide ballistic resistant protection from vantage points around the substations. Ballistic shields offer greater protection than alternative solutions. The topography surrounding these critical substations and transformers, in most cases, eliminate the effectiveness of perimeter substation ballistic walls and other solutions which are not specifically designed for closer proximity to energized equipment. These alternative options are not suitable to address a ballistic attack in all cases. For example, the line-of-sight assessment for one of these critical substations identified a nearby elevated site, external to the substation, which would require a perimeter wall with a height of nearly 70 feet to mitigate the line-of-sight ballistic threat. A ballistic shield offers a proximity solution that is more effective and feasible in such instances.

The Company also evaluated a transformer wrap solution which is installed directly on the transformer tank and foundation requiring transformer specific designs so each transformer can be uniquely retrofitted. Although effective for addressing the line-of-sight threat while providing ballistic protection to the transformer, control cabinet, oil pumps and fans, this solution provided no ballistic protection to the transformer bushings. Additionally, there were transformer cooling concerns with the application of this solution, and it did not appear effective in providing a non-ricochet solution. The fiberglass reinforced panel walls the Company selected are

lightweight, corrosion proof, non-conductive, electromagnetically transparent, and provide a non-ricochet solution which retains the projectile.

9. Q. WHY WERE THE PROJECTS NECESSARY?

A. In 2022, the utility industry experienced a concerning pattern of attacks and threats to electric substations through physical damage and service disruptions. There are numerous media examples which highlight this pattern. One example is a USA Today article from February 2023 that describes the emerging pattern on substations being attacked.[1]

These attacks, along with widespread media coverage, highlighted the vulnerability of the power grid to physical threats. Media attention and proliferation of extremist content on the internet may exacerbate these threats, emboldens the attackers, and inspire copycats. For example, extremist internet content encourages ballistic attacks against critical infrastructure, and real ballistic attacks against Pacific Gas and Electric, Duke Energy, and others, demonstrate the risk is not merely hypothetical. Without advanced security initiatives, ballistic attacks against critical assets represent a dangerous nexus between being relatively easy to execute and creating high-impact damage, especially where line-of-sight vulnerabilities exist due to elevated terrain outside the substation. These projects improve the physical security posture of the Company's critical assets to mitigate impacts from ballistic attacks on the most critical substation transformers.

[1] Dinah Voyles Pulver and Grace Hauck, Attacks on power substations are growing. Why is the electric grid so hard to protect?, USA Today, Feb. 8, 2023.
https://www.usatoday.com/story/news/nation/2022/12/30/power-grid-attacks-increasing/10960265002

10. Q. IS THE COMPANY AWARE OF AN INCREASE IN THE NUMBER OF HUMAN-RELATED DISTURBANCES AND UNUSUAL INCIDENTS AFFECTING THE ENERGY SECTOR ACROSS THE UNITED STATES?

A. Yes, the Company is aware of an increased number of unusual incidents and human related disturbances against the energy sector within the United States. Based on incidents reported to the Department of Energy, there has been a material increase in events. In each year since 2017, there has been more human-related disturbances and unusual incidents than the year prior, and 2022 experienced a concerning increase in events over 2021. In 2022, the energy sector experienced about 3.8 times as many incidents that occurred in 2017. The pattern experienced over this period can be viewed as a proxy for the increased threat, and increased probability of an attack occurring to the Company's infrastructure.

For example, On December 3, 2022, a shooting attack was carried out on two electrical distribution substations located in Moore County, North Carolina. Damage from the attack left up to 40,000 residential and business customers without electrical power. Forty-five days after those attacks, gunfire damaged a substation about 50 miles away in Randolph County.

Additionally, the most notable substation attack carried out on Pacific Gas and Electric Company's Metcalf transmission substation included shooters firing on 17 electric transformers resulting in nearly $20 million worth of equipment damage. Although this attack did not result in any customer outages a similar attack to a critical substation could result in a widespread system outage.

11. Q. HOW DID THE COMPANY DETERMINE WHICH TRANSFORMERS WERE CRITICAL AND WARRANT BALLISTIC SHIELDS?

A. The Company utilized an existing risk assessment methodology required by the North American Electric Reliability Corporation ("NERC") critical infrastructure protections ("CIP") physical security requirements to identify the most critical transmission substations, which if rendered inoperable or damaged due to physical attack, could result in widespread system instability, uncontrolled separation, or cascading outages within the electric grid interconnection.

The Companies utilize the guidelines specified in the CIP-014-3 standard for performing transient stability analysis, voltage stability analysis, post-transient analysis, cascading analysis, and load shed analysis based on Security Constrained Dispatch (SCD). The methodology will assume all lines, without regard to voltage level, are disconnected from each qualifying Transmission station or substation as the result of a physical attack. Each Transmission substation is then assessed individually in a transient and voltage stability simulation to assess the potential for uncontrolled separation or cascading within an interconnection.

Once these critical substations were identified, their physical threat and vulnerability assessments were re-evaluated to identify unique characteristics of the surrounding terrain which present potential line-of-sight ballistic attack vulnerabilities, which can originate from outside the high-security substation perimeter walls and electronic security system boundaries.

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12. Q. DO THESE SUBSTATIONS HAVE A PRIOR HISTORY OF BALLISTIC ATTACKS?

A. Yes. There have been multiple incidents where several gunshot rounds have penetrated the transformer cooling radiator of a unit that is within the scope for these ballistic shields. Although there was no direct evidence to support either an unintentional or intentional coordinated attack, these incidents demonstrate the risk and vulnerability that exists.

13. Q. DO OTHER COMPANY SUBSTATIONS HAVE A RECENT HISTORY OF BALLISTIC ATTACKS?

A. Yes. In the last several years, the Companies have had multiple ballistic attacks that have impacted the operations of substation or transmission lines.

Grass Valley Substation transformer was shot in January 2020. The primary damage was due to a bullet hole in the transformer radiator. The damage resulted in the de-energization of the substation.

The Gonder Substation was shot in March 2020. The shooting occurred in the evening and three rounds struck the substation. Due to the location of the shots, the substation remained operational immediately following the incident however offline repairs were later required.

The Mira Loma Substation was shot in July 2020. The transformer was hit and created an oil leak. The substation had to be de-energized due to the damage.

14. Q. IS THE COMPANY AWARE OF OTHER RECENT POTENTIAL ATTACKS TO COMPANY SUBSTATIONS?

A. Yes. The most notable recent event occurred in 2020. Several men with ties to the U.S. military and anti-government "boogaloo" movement planned to firebomb an NV Energy substation to create civil unrest. The Companies worked with local and national law enforcement which ultimately led to the arrest of three men before the attack could be carried out.

15. Q. IF ONE OF THESE CRITICAL SUBSTATIONS EXPERIENCED A COORDINATED ATTACK WHAT WOULD THE ESTIMATED COST AND LEAD TIME BE TO RESTORE SERVICE?

A. The actual cost and lead time would be dependent on the extent of the damage. However, as a proxy, the replacement cost and lead time for a similar transformer is approximately $4 million each and up to 36 months.

Although the Company has critical spares to mitigate unplanned in-service failures an attack which results in the failure of all or the majority of the transformers at one of these critical sites could easily exceed $50 million. Beyond the replacement and construction costs, the lead time however provides an unacceptable outcome due to the critical nature of these sites and is the primary driver for the project.

16. Q. WHAT IS THE TOTAL COST OF THE PROJECTS?

A. The estimated total cost of the completed projects through December 31, 2023, is $31,672,839 (with AFUDC). All the facilities are expected to be installed during the ECIC period, after the end of the certification period on May 31, 2023, and used and useful in the provision of utility service. Due to the increasing number of

human-related disturbances and unusual incidents affecting the energy sector coupled with supply chain challenges and longer lead time for large substation transformers it is prudent to execute and expedite these physical security enhancements to mitigate ballistic attacks to ensure ongoing reliable service.

17. Q. NRS 704.110(4) STATES THAT AN ITEM INCLUDED IN THE ECIC PERIOD MUST BE "REASONABLY KNOWN AND MEASUREABLE WITH REASONABLE ACCURACY." ARE THE EXPECTED COSTS OF THE SUBSTATION TRANSFORMER BALLISTIC SHIELDS EQUIPMENT "REASONABLY KNOWN AND MEASURABLE WITH REASONABLE ACCURACY" AS OF THE DATE YOUR TESTIMONY IS BEING PREPARED?

A. Yes. Contracts for the multi-sided ballistic transformer shields have been executed and purchase orders include the following estimate:

- [redacted] $16,724,000
  - Four 500/230 kV transformer shields
  - Two 500 V phase shifters shields
- [redacted] - $8,362,000
  - Two 345/230 kV transformer shields
  - Two 345 kV phase shifter shields
  - Four 500/230 kV transformer shields

These contracts total $25.1 million and represent 79 percent of the total project's costs. The remaining balance consists of engineering, installation labor and associated projects overheads.

18. Q. NRS 704.110(4) STATES THAT THE COMMISSION SHALL FIND THAT AN EXPECTED CHANGE IS REASONABLY KNOWN AND MEASURABLE WITH REASONABLE ACCURACY IF, AMONG OTHER THINGS, IT CONSISTS OF <u>SPECIFIC AND IDENTIFIABLE EVENTS</u> OR PROGRAMS RATHER THAN GENERAL TRENDS, PATTERNS OR DEVELOPMENTS. DOES THE SUBSTATION TRANSFORMER BALLISTIC EQUIPMENT SHIELDS PROJECTS MEET THAT CRITERION?

A. Yes. The projects scopes are to acquire and install multi-sided ballistic protection which includes the engineering, purchase, delivery, and installation of these shields based on contract purchase orders and detailed delivery schedules, and cannot be characterized as a general trend, pattern, or development. Due to the increased threat of ballistic attacks originating from the surrounding elevated terrain in proximity to these critical substations, specific critical transformers warrant enhanced ballistic protections that may not be warranted on most transformers. As a result, these projects are not considered to be classified as general trends, patterns, or developments.

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19. Q. NRS 704.110(4) STATES THAT THE COMMISSION SHALL FIND THAT AN EXPECTED CHANGE IS REASONABLY KNOWN AND MEASURABLE WITH REASONABLE ACCURACY IF, AMONG OTHER THINGS, IT HAS AN OBJECTIVELY <u>HIGH PROBABILITY OF OCCURRING TO THE DEGREE, IN THE AMOUNT AND AT THE TIME EXPECTED.</u> DOES THE SUBSTATION TRANSFORMER EQUIPMENT BALLISTIC SHIELDS PROJECTS MEET THAT CRITERION?

A. Yes. Revised production and delivery schedules provided by the vendor demonstrate completion of manufacturing, testing and delivery to the substation by October 2023, which satisfies the current construction schedule to install and commission the ballistic shields by December 31, 2023.

20. Q. NRS 704.110(4) STATES THAT THE COMMISSION SHALL FIND THAT AN EXPECTED CHANGE IS REASONABLY KNOWN AND MEASURABLE WITH REASONABLE ACCURACY IF, AMONG OTHER THINGS, IT IS PRIMARILY MEASUREABLE BY <u>RECORDED OR VERIFIABLE REVENUES AND EXPENSES</u> AND IS EASILY AND <u>OBJECTIVELY CALCULATED,</u> WITH THE CALCULATION OF THE EXPECTED CHANGES RELYING ONLY SECONDARILY ON ESTIMATES, FORECASTS, PROJECTIONS OR BUDGETS. DOES THE SUBSTATION TRANSFORMER BALLISTIC EQUIPMENT SHIELDS PROJECTS MEET THAT CRITERION?

A. Yes. All the projects material costs related to the purchase and delivery of the multi-sided transformer ballistic shields are currently verifiable and recorded in the contracts and purchase orders, as set forth in Q&A 17 above. The total estimate for

linear feet of ballistic shields may change based on the final design. The required civil design and installation costs are currently estimates considered to be accurate.

21. Q. PLEASE SUMMARIZE WHY THE SUBSTATION TRANSFORMER BALLISTIC EQUIPMENT SHIELD PROJECTS MEETS THE CRITERA SPECIFIED IN NRS 704.110(4) AS AN EXPECTED CHANGE THAT IS REASONABLY KNOWN AND MEASURABLE WITH REASONABLE ACCURACY.

A. The Substation Transformer Ballistic Shield projects constitutes a specific and identifiable event, these events have an objectively high probability of occurring, in the amount and at the time expected, and their costs are currently measurable by recorded and verifiable expenses and estimates that are easily and objectively calculated.

22. Q. NRS 704.110(4) STATES THAT THE COMMISSION SHOULD CONSIDER "REASONABLE PROJECTED OR FORECASTED OFFSETS IN REVENUE AND EXPENSES THAT ARE DIRECTLY ATTRIBUTABLE TO OR ASSOCIATED WITH THE EXPECTED CHANGES IN CIRCUMSTATNCES UNDER CONSIDERATION." ARE THERE ANY OFFSETS ASSOCIATED WITH THE ACQUISITION AND CONSTRUCTION OF THE SUBSTATION TRANSFORMER EQUIPMENT BALLISTIC SHIELDS?

A. The Company has not identified any reasonable projected or forecasted offsets in revenues or expenses that are directly attributable to or associated with these expected changes in circumstances.

23. Q. IS THE COMPANY REQUESTING CONFIDENTIAL TREATMENT OF CERTAIN INFORMATION CONTAINED IN YOUR TESTIMONY?

A. Yes. Substation site names have been redacted due to the critical nature of these facilities protected under Nevada's Homeland Security Act, codified in NRS 239C.210 and Federal Laws relating to Critical Energy Infrastructure Information and Controlled Unclassified Information.

24. Q. PLEASE DESCRIBE THE CONFIDENTIAL MATERIAL.

A. The redacted material includes the names of the two critical substations, which if operationally impacted, could result in widespread instability, uncontrolled separation, or cascading outages within the interconnection. Keeping the critical substation names confidential eliminates potential increased attack risk exposure to the sites due to their critical nature to the electric grid.

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

A. The requested period for confidential treatment is for a period of not less than five years.

26. 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 can be provided to Staff and the BCP under standardized protective agreements with them. However, the name of the substation sites should

not be required for Staff or the BCP to evaluate the Company's application and participate in the docket.

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

A. Yes.

EXHIBIT LANGDON-DIRECT-1

STATEMENT OF QUALIFICATIONS

Joshua Langdon
Vice President, Transmission
NV Energy
7155 Lindell Rd
Las Vegas, Nevada 89118
(702) 402-6600

My name is Joshua Langdon. I am the Transmission Vice President for Sierra Pacific Power Company and Nevada Power Company ("Companies"). The Transmission business unit includes Telecommunication, Substation, and Transmission and Distribution system Operations for the Companies.

I graduated from the University of Nevada – Las Vegas in December of 2007 with a Bachelor of Science degree in Electrical Engineering. I received a master's in business administration from University of Nevada – Las Vegas in May of 2016. I am a licensed Professional Engineer in Nevada. In January of 2008, I joined the Companies as an associate Electrical Engineer in Generation Engineering. I remained in the department for four years progressing to Sr. Engineer. In these roles, my primary responsibilities were to provide engineering, project management construction and commissioning support for power generation electrical system upgrades and retrofits. Additionally, I provided reliability inspections, equipment testing and outage restoration support for all the Companies' generating stations.

In August of 2012, I was selected as the Plant Engineering Manager for several Nevada Power generating stations. In this role, I supported daily engineering, operational and maintenance functions while establishing long-term strategic planning and capital investments to ensure continued safe and reliable operations.

In December of 2015, I was selected as the Maintenance Manager for Nevada Power's Walter Higgins and Goodsprings Generating Stations. In this capacity, I was responsible for all plant maintenance, capital investments, engineering, and plant outage management to ensure continued safe and reliable operations.

In December of 2017, I was selected to be the Plant Director at Nevada Power's Nellis Solar and Las Vegas Generating Stations. Within this role, I was responsible for all requirements to ensure safe and reliable operations. Additionally, I focused on improving plant safety and reliability while optimizing plant operations to meet the growing demand for flexible operating conditions.

In January of 2019, I was selected as the Director of Grid Operations and Reliability. Within this role, I was responsible for the Companies' Balancing Authority, Transmission and Distribution operating functions.

In May of 2020, I was selected to my current role as the Vice President of Transmission where I am responsible for safe, reliable, and compliant real time operations of the Companies Telecommunication, Substation and Transmission and Distributions systems.

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, JOSHUA LANGDON, 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: June 5, 2023

Joshua Langdon

JOHN LESCENSKI

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 23-06___
2023 General Rate Case

Prepared Direct Testimony of

John Lescenski

Revenue Requirement

SECTION 1. INTRODUCTION

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" or the "Company) 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 Nevada Power.

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 for the Companies' generation fleet.

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

A. Yes. I provided testimony in the Companies' past filings for deferred energy, integrated resource plans ("IRPs") and general rate cases ("GRCs"), most recently in Docket Nos. 22-11032, 22-06014, 23-03005 and 22-03006.

4. Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes, I am. In addition to my Statement of Qualifications (**Exhibit Lescenski-Direct-1**), I sponsor **Exhibit Lescenski-Direct-2**, which identifies major generation plant additions completed since the close of the certification period in Nevada Power's 2020 GRC proceeding (May 31, 2020) through close of certification period in this GRC (May 31, 2023).

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

A. I support the reasonableness of test period operations and maintenance expenditures at Nevada Power's fleet of generating stations, as well as its request to include in rate base the costs associated with generation-related capital additions that have gone into service since the close of the certification period in Nevada Power's last GRC, Docket No. 20-06003.

In Section II, I describe the processes within the generation area and Company-wide that govern the expenditure of both operations and maintenance ("O&M") dollars and capital investment.

In Section III, I support Nevada Power's investment in generation capital projects at Nevada Power's conventional generating stations that were completed between the close of the certification period in Nevada Power's 2020 GRC and the close of the test period for this 2023 GRC (December 31, 2022) ("Test Period"). These projects closed to plant in service are in service and used and useful in providing electric service to customers between June 1, 2020, and December 31, 2022.

In Section IV, I support the Long-Term Service Agreement ("LTSA") costs for outages completed in the Test Period, and expected LTSA outage costs anticipated during the certification period, January 1, 2023, through May 31, 2023 ("Certification Period").

In Section V, I support capital projects anticipated to be placed in service and used and useful in providing electric service in the Certification Period. The completion of these projects and their actual costs as of May 31, 2023, will be "certified" as a part of the Company's certification filing.

In Section VI, I support two large projects that are anticipated to be placed in service and used and useful in providing electric service between June 1, 2023, and December 31, 2023, as Expected Change in Circumstances ("ECIC") projects.

6. Q. DO YOU SPECIFICALLY DISCUSS IN YOUR TESTIMONY ALL GENERATION PROJECTS CLOSED TO PLANT IN SERVICE IN TEST PERIOD AND CERTIFICATION PERIOD?

A. No. While I support all generation plant investment reflected in the Company's proposed calculations of rate base, my testimony specifically discusses individual projects that cost $1.0 million or more. Nevada Power's generation team completed many projects under $1.0 million since May 31, 2020. In recent GRCs, the Commission has accepted the $1.0 million demarcation as appropriate for determining whether a project is "major." While not addressed in detail in my prepared direct testimony, my department has prepared project "binders" for smaller projects completed since June 1, 2020. As has been Nevada Power's practice for many rate-case cycles, those binders (now in electronic form) are available for review in this GRC filing.

SECTION 2. O&M AND CAPITAL COST CONTROL

7. Q. HOW DOES NEVADA POWER CONTROL THE EXPENSES ASSOCIATED WITH OPERATING AND MAINTAINING ITS FLEET OF GENERATING PLANTS?

A. Controlling O&M is important to keep electric prices reasonable for the Companies' customers. At both Nevada Power and Sierra, cost discipline begins with a production schedule that forecasts the amount of energy that can be expected from the facility over the next 10 years. Then each power plant management team carefully reviews all expenditures associated with running the power plants for which they are responsible. Plant managers use the production schedule, equipment condition assessments and

Original Equipment Manufacturer ("OEM") recommendations to create an expenditure plan for each facility. Each power plant's expenditure plan is then rolled up into an overall expenditure plan for the fleet.

8. Q. WHAT IS YOUR PROJECTION FOR FUTURE EXPENSES FOR THE NEVADA POWER'S GENERATING FLEET?

A. The fixed costs to maintain generating units as reliable capacity resources remain relatively flat year over year (subject to inflation). Variable expenses are less predictable, as these costs depend on how units within the fleet are used. Most variable expenses are related to chemicals and other consumables, the costs of which increase with inflation, and the quantity of which vary according to each unit's actual operations during the year. Other variable expenses are related to wear and tear.

On a daily basis, the generating fleet cycles on and off and from low load to high load to provide the lowest cost energy supply for Nevada Power's customers. That cycling leads to wear and tear, and as the facilities age, equipment and systems will deteriorate, requiring increased maintenance expense to ensure compliance with operating standards and reliability for Nevada Power's customers. The last major addition of a new plant to the Nevada Power fleet was the Harry Allen combined-cycle plant, which was put in service in 2011. Nevada Power's fleet is aging, and as units age, the cost of maintaining the units increases.

In this context, the Company continues to work diligently to achieve high reliability levels while maintaining O&M cost discipline so that customers can enjoy reliable service at reasonable prices.

9. Q. HOW DOES NEVADA POWER MANAGE CAPITAL INVESTMENTS IN THE GENERATING FLEET?

A. The generation team focuses on delivering the best value from the capital investment projects that are performed at the plants. Capital investment plans are developed in parallel with the expenditure plans described above. The starting point for the capital investment plan is the same unit-by-unit 10-year production forecast. Key assumptions are made concerning retirement, safety, risk management, environmental and other compliance requirements. Each plant team evaluates the current and expected performance of the units, and proposes capital investments needed to deliver reliability at a reasonable cost. The benefits of each capital investment are analyzed based on the planned remaining life of the unit.

For each of the generation projects described in my testimony, Nevada Power plant and project managers followed a rigorous capital budgeting process, which guides the development of business cases and project estimates and governs how projects are managed, including through monthly reporting of schedule and budget status.

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10. Q. WERE ALL OF THE CAPITAL PROJECTS COMPLETED SINCE THE END OF THE CERTIFICATION PERIOD IN NEVADA POWER'S 2020 GRC PRE-APPROVED BY THE COMMISSION?

A. No. The majority of the projects would be considered maintenance capital to ensure the safe and reliable operation of the generating plants. These projects are not presented to the Commission for pre-approval. However, two projects were presented to, and approved by, the Commission in previous IRP filings. These projects are:

- Chuck Lenzie Block 2 Turbine Upgrades in Docket No. 21-06001
- Silverhawk Turbine Upgrades in Docket No. 21-06001

11. Q. PLEASE DESCRIBE THE PROCESS THAT NEVADA POWER USES TO MANAGE ITS CAPITAL INVESTMENTS.

A. Nevada Power's Generation team follows a robust business planning and project management oversight process. I describe each process in turn below.

12. Q. PLEASE DESCRIBE THE BUSINESS PLANNING PROCESS FOR GENERATION CAPITAL PLANNING.

A. Business planning begins with a 10-year Generation Capital Plan ("Capital Plan"), which includes a list of capital projects for each generating plant. The Capital Plan is updated annually. During the annual update process, each plant performs a fresh assessment and may identify new projects that are required, may modify existing projects and may remove projects from the Capital Plan as appropriate.

A business case is developed for every project that is included in the Capital Plan. The Business case documents the justification for the project and includes the scope, schedule and an estimated cost, as well as a cost-benefit analysis. Because the Capital Plan spans 10 years into the future, many of the initial business cases are based on a preliminary scope and schedule and utilize cost estimates. As a project is further developed, preliminary engineering is performed, a detailed scope of work and schedule are established, and a detailed cost estimate is prepared. The initial business case is updated with new information as it becomes available, and the cost-benefit analysis is reassessed to determine whether the project should remain in the Capital Plan.

All Generation capital projects, and their business cases are reviewed by the Generation leadership team. The Generation leadership team prioritizes the entire portfolio of capital projects as part of the 10-year business planning process. Projects mandated by legal or regulatory requirements, safety and environmental compliance receive top priority. Other factors, such as improving or maintaining reliability, costs and efficiency, are only considered after legal, regulatory, safety and environmental projects are prioritized and funded.

All capital projects from each business unit within Nevada Power are submitted for cross-department review and prioritization as part of the Company-wide 10-year business planning process. This step subjects Generation's capital project prioritization to peer review from other business units and prioritization among the entire capital portfolio.

Capital projects that progress through the Generation business unit, peer review and the prioritization process are then submitted for funding approval by executive management. Only approved projects are included in the approved Capital Plan.

13. Q. PLEASE DESCRIBE THE PROJECT MANAGEMENT OVERSIGHT PROCESS.

A. Inclusion of a project in the approved Capital Plan does not constitute final internal project approval. Specific project approvals must still be obtained. This process begins with the assignment of a project manager, who is responsible for executing a project or projects in the Capital Plan. The project manager is required to submit an Authorization for Expenditure ("AFE") for approval prior to commencing a project. The AFE includes the most current information regarding estimated project cost, budget information, and the business case. The AFE serves as a business control to ensure construction projects, plant additions and significant unbudgeted expenses are reviewed and approved by the appropriate levels of management before funds are committed and spent.

Project managers may submit a preliminary AFE requesting funds to perform engineering in order to fully develop a capital project's scope, schedule and budget. In these situations, the project manager is then required to update the business case and submit a supplemental AFE for the full funding of the project prior to committing and spending additional funds.

A Standard Project Proposal ("SPP") is prepared for capital projects exceeding $1 million and submitted with the AFE for management review and approval. The SPP template is designed to provide a consistent collection of supporting information to management and regulators. Depending on the size and complexity of the proposed project, business units can append additional relevant information to the SPP template.

Project managers are responsible for monitoring actual and forecast spending against the approved project funding amounts in the approved AFE. Project managers provide monthly cost, schedule and scope updates for each project to Generation management. Each business unit performs a thorough review and analysis of its capital portfolio each month. Business units review project performance with project managers. Business units forecast capital spending, analyze budget variances, perform peer reviews and report results to Corporate Finance and to the executive team monthly.

14. Q. PLEASE ADDRESS DISCRETIONARY SPENDING AS IT RELATES TO NEVADA POWER'S CAPITAL MANAGEMENT PROCESS.

A. As explained above, capital is prioritized first by legal, regulatory, safety and environmental requirements, then by financial considerations including costs, reliability and efficiency. Discretion is used across the prioritization process with the exception of projects designated as mandated by legal or regulatory requirements. The number of requests for investment are usually more than the entire capital budget. Management

must use discretion in selecting which safety and environmental projects (that are not otherwise required by law) are given priority over others. These decisions are typically based on the number of impacted employees, severity of the risk and whether administrative controls are possible.

15. Q. HOW IS DISCRETION APPLIED TO FINANCIALLY JUSTIFIED PROJECTS?

A. Again, far more requests are made for capital investment than can be funded under the budget. While forced ranking of projects by financial metrics (such as cost/benefit and profitability indexes) creates a prioritized listing, other points are also considered. Some capital projects are tied to planned outages or other customer requirements. This may adjust the relative ranking or timing of an investment. Additionally, an emerging risk (e.g., security enhancements) may impact the relative ranking. Finally, some projects may be marginally economic based on assumptions such as retirement date or expected impacts on expense or workforce. In these circumstances, discretion must be used in evaluating the financial analysis. An example could be a retirement date. No one can predict a retirement date with exact certainty, and this is especially true when the date used for planning and depreciation is several years out.

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SECTION 3. GENERATION INVESTMENT BETWEEN JUNE 1, 2020, AND DECEMBER 31, 2021

16. Q. PLEASE ADDRESS THE MAJOR PROJECTS THAT WERE COMPLETED BETWEEN JUNE 1, 2020, AND DECEMBER 31, 2022.

A. Nevada Power has made major investments in its generation fleet since the close of the certification period in the 2020 GRC. In order, I discuss investment at:

A. Chuck Lenzie Generating Station ("Lenzie")

1.	CL2089	LZ Gas Supply Piping System, Install
2.	CL2116	NP 20 MW 7F (Lenzie CT3), Upgrade
	CL2117	NP 20 MW 7F (Lenzie CT4), Upgrade
	CL2118	NP 20 MW 7F (Lenzie CT1), Upgrade
	CL2119	NP 20 MW 7F (Lenzie CT2), Upgrade
3.	CL2127	LZ PB2 Bal. of Plant Controls
4.	CL2179	LZ PB1 Chemical Injection Building, Replace
	CL2182	LZ PB2 Chemical Injection Building, Replace
5.	CL2220	LZ CT4 Compressor Rotor, Replace

B. Clark Station ("Clark")

1.	CS2027	Clark-11A Power Turbine Upgrade and Overhaul
	CS2034	Clark - 19 A Power Turbine Upgrade and Overhaul
2.	CS2153	CK PKRS - Repl Stack Outlet Exp Joints (12)
3.	CS2201	Clark Unit 5 - CT - Hot Gas Path Inspection
	CS2202	Clark Unit 6 – CT – Hot Gas Path Overhaul
4.	CS2223	CK PKRS Fuel Gas Control Valves and Drivers
5.	CS2238	CK - PKRS – Purchase Capital Spare Generator
6.	CS2251	CK - PKRS – PB 1-3 – Bus Duct – Rebuild
7.	CS2286	CK - Unit 18 B Gas Generator Rebuild
	CS2317	CK - Unit 20 B - Gas Generator
	CS2344	CK - Unit 15 B - Gas Generator
	CS2348	CK - Unit 22 B - Gas Generator
	CS2351	CK - Unit 20 A - Gas Generator
	CS2352	CK - Unit 18 A - Gas Generator
	CS2368	CK - Unit 19 A - Gas Generator
	CS2361	CK - Unit 21 A - Gas Generator
8.	CS2346	CK - Capital Spare GG8 Gas Generator

C. Harry Allen Generating Station ("Harry Allen")

1.	HA2153	HA4 Combustion System
2.	HA2190	HA3 CT Wet Compression System, Install
	HA2191	HA4 CT Wet Compression System, Install
3.	HA2206	HA4 Generator Rewind

D. Las Vegas Generating Station ("LVGS")
1. LC2177 LC Ovation, Install

E. Silverhawk Generating Station ("Silverhawk")
1. SH2036 SH CTB Rotor, Replace
2. SH2073 SH Turbine Controls System, Replace
3. SH2089 SH HRSG A Liner, Replace
SH2093 SH HRSG B Liner, Replace
4. SH2105 SH ST Major Capital
5. SH2117 NP 17 MW 501F (Silverhawk CTA), Upgrade
SH2118 NP 17 MW 501F (Silverhawk CTB), Upgrade
6. SH2232 SH CT Wet Compression System, Install

F. Sun Peak Generating Station ("Sun Peak")
1. SK2023 Sun Peak Unit 4 GT – Hot Gas Path Overhaul

G. Higgins Generating Station ("Higgins")
1. WH2163 WH2 Generator Exciter, Replace
2. WH2170 WH1 Compressor Diaphragms, Replace
3. WH2171 WH CT Wet Compression System, Install

A. CHUCK LENZIE GENERATING STATION

1. CL2089 – Lenzie Gas Supply Piping System

17. Q. PLEASE DESCRIBE THE LENZIE GAS SUPPLY PIPING SYSTEM PROJECT AND WHY IT WAS NECESSARY.

A. Lenzie was designed with a single natural gas supply piping system to feed both power blocks. The natural gas piping is a subsurface buried line with protective coatings and partial cathodic protection designed to assist with corrosion prevention.

An inspection of the cathodic protection on this piping was completed in March 2019. The inspection was limited to three areas where excavation exposed the underground piping. The report concluded that there was at least one section of the piping with no cathodic protection. This section had experienced coating failures and maintained obvious corrosion

indications. Based on this observation, it was expected that other sections of the piping were also at risk of corrosion and possible failure. Corrosion of this underground gas supply pipeline presented a high-level safety hazard with potential for leakage and/or explosion. The section of pipe that did have cathodic protection was at risk as the zinc ribbon anode was nearing the end of its useful life.

In addition, because only one natural gas pipe provided fuel to both power blocks (1160 MW) of Lenzie, there was a significant risk for loss of the facility's ability to generate electricity when the gas supply line is removed from service.

18. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?

A. The total plant in service for this project was $2,019,751, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the costs of the project were prudently incurred. The total project cost was $1,653,490, excluding AFUDC, and was estimated at $930,713, excluding AFUDC.

2. CL2116, CL2117, CL2118 and CL2119 – NP 20 MW 7F Upgrade

19. Q. PLEASE DESCRIBE THE LENZIE GAS TURBINE UPGRADE PROJECTS AND WHY THEY WERE NECESSARY.

A. The Company performed combustion turbine ("CT") upgrades at Lenzie to achieve an increase in the units' megawatt output and improve the units' efficiency through replacing the following turbine components with an

upgraded design: compressor stage zero stationary and rotating blades, combustion system components, turbine stage 1, stage 2 and stage 3 components. Additional operational flexibility improvements were provided through upgrading the combustion system, the addition of auxiliary systems and by modifying the turbine control system.

The scope of work for the General Electric ("GE") CT upgrades included replacing critical turbine components with upgraded components and the addition of auxiliary turbine systems. Control system modifications were required but are part of a separate cyber security controls upgrade project. The GE package included the following:

CT Upgrades Completed:

- Replaced combustion fuel nozzles, caps, and liners with an upgraded design.
- Replaced turbine stage 1, stage 2, and stage 3 components with an upgraded design. Turbine Controls Mark VI to VIe Platform Upgrade

The following software upgrades were also included:

- OpFlex Enhanced Transient Stability Model Based Controls platform
- Firing temperature increase and revised Model Based Control software changes
- Variable IGV Angle Optimization:
    - OpFlex Variable IGV Angle Optimization software
    - OpFlex Variable IGV Angle Optimization HMI screens
    - Controls specifications update (MLL A010 and A210)

20. Q. WERE ANY OF THESE PROJECTS PREVIOUSLY PRESENTED TO THE COMMISSION?

A. Yes. The upgrades to Lenzie Power Block 2 (CT3 – CL2216 and CT4 CL2117) were presented to and approved by the Commission in the Companies' 2021 Joint IRP filing in Docket No. 21-06001. The Commission approved these two projects in its Phase I Order issued on September 28, 2021. Power Block 1 was discussed in Docket No. 21-06001, but due to the project being completed in the spring of 2021, it was not requested for approval in the docket.

21. Q. WHAT WAS THE TOTAL COST OF THE PROJECTS?

A. The total plant in service recorded as of the end of the Test Period for these projects are shown in the **Table Lescenski-Direct-1**:

Table Lescenski-Direct-1

Budget ID	Unit	Estimate (Without AFUDC)	Actual Cost (Without AFUDC)	Total Plant in Service (Including AFUDC
CL2116	Lenzie CT3	$ 24,360,807	$ 22,044,293	$ 23,256,170
CL2117	Lenzie CT4	$ 24,360,807	$ 22,138,332	$ 23,406,689
CL2118	Lenzie CT1	$ 23,401,762	$ 23,367,854	$ 23,698,471
CL2119	Lenzie CT2	$ 23,401,762	$ 23,361,608	$ 23,685,926

3. CL2127 Lenzie Power Block 2 Balance of Plant Controls

22. Q. PLEASE DESCRIBE THE LENZIE BALANCE OF PLANT CONTROLS PROJECTS AND WHY THEY WERE NECESSARY.

A. The Lenzie Balance of Plant systems currently includes the water treatment system, chiller systems, duct burner systems, Nalco water chemistry systems, and the auxiliary boiler systems. Each of these systems had separate control systems from different manufacturers and were spread across different generations of technology. Combining these systems under one Distributed Control System ("DCS") replaced and unified the control systems that had varied systems, varied support, inadequate cyber protection, internal data being used externally, no visibility in the control room, and no support from the Monitoring and Diagnostic Center. This project added greater functionality, versatility, protection, visibility, and uniformity to the current Balance of Plant systems. In addition, the GE Mark VI Turbine Controls were updated to meet the vulnerability management standard as part of the cyber security profile requirements.

23. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?

A. The total plant in service for this project was reported, as $21,173,198. However, the project was mistakenly in-serviced in December 2022, but it will not be completed and in service until the Certification Period. The project costs are further described in the Section V of my testimony. The plant in service for this project will be corrected in Nevada Power's Certification filing in this Docket.

4. CL2179 and CL2182 – Lenzie Chemical Injection Building Replacement

24. Q. PLEASE DESCRIBE THE LENZIE CHEMICAL INJECTION BUILDING REPLACEMENT PROJECTS AND WHY THEY WERE NECESSARY.

A. Chemistry control for the chiller cooling towers at Lenzie is accomplished by pumping sulfuric acid for pH control and sodium hypochlorite (bleach) for biofouling prevention. The acid and bleach are stored in bulk tanks, where they feed small metering pumps inside the chemical control buildings. These pumps deliver a controlled amount of chemical to each chiller cooling tower as needed based on online instrumentation. These metering pumps, and the associated control and monitoring instrumentation were housed inside small skid mounted buildings, which were located inside a chemical containment basin. Over the past few years, Lenzie experienced frequent small acid leaks inside the chemical control building requiring frequent repairs and cleanup. Recently, a contract employee was exposed to chemical fumes while calibrating equipment in the building. This exposure required the employee to be hospitalized overnight for monitoring. To reduce the risks associated with this system, the buildings were removed, and new equipment (pumps and more robust piping) was reconfigured under a three walled shade structure to provide maximum room and ventilation. The acid and bleach systems were also relocated on separate intermediate containments to prevent mixing.

25. Q. WHAT WAS THE TOTAL COST OF THE PROJECTS?

A. The total plant in service for project CL2179 was $1,876,852 and CL2182 was $1,992,061, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The projects were prudently designed and constructed, and the costs of the projects were prudently incurred. The total project cost for CL2179 was $1,975,727, excluding AFUDC, and was estimated at $2,162,908, excluding AFUDC. The total project cost for CL2182 was $1,992,061, excluding AFUDC, and was estimated at $2,162,908, excluding AFUDC.

5. CL2220 – Lenzie Combustion Turbine Rotor Replacement

26. Q. PLEASE DESCRIBE THE LENZIE COMBUSTION TURBINE ROTOR REPLACEMENT PROJECT AND WHY IT WAS NECESSARY.

A. Lenzie CT 4 is a GE 7F model, serial number 297759. A crack was discovered on a row 1 compressor rotating blade during inspections performed at the planned Lenzie major outage. Multiple vendors (GE and Power Systems Manufacturing) recommended immediate replacement of the blade. Ignoring this recommendation would likely result in blade liberation and catastrophic damage to the unit. The replacement of the blade includes an extensive scope of work (de-stacking the rotor) that can only be completed in a service shop.

Row 1 compressor blade cracking is a known fleet issue documented in GE Technical Information Letter ("TIL") 1638-R2. The TIL states that row 1 compressor blades should be inspected at each planned maintenance

outage. If cracking is found on the row 1 compressor blades, they should be immediately replaced in a GE service shop. Due to component availability and duration for the replacement, the most cost-effective option was to replace the entire compressor rotor with a new rotor.

27. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?

A. The total plant in service for this project was $6,381,185, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the costs of the project were prudently incurred. The total project cost was $6,371,603, excluding AFUDC, and was estimated at $6,336,000, excluding AFUDC.

B. CLARK STATION

1. CS2027 and CS2034 – Clark Peakers 11A and 19A Power Turbines

28. Q. PLEASE DESCRIBE THE CLARK PEAKING UNITS 11A AND 19A POWER TURBINE UPGRADE AND OVERHAUL PROJECTS AND WHY THEY WERE NECESSARY.

A. In October 2016, Clark Peaker Unit 21B Power Turbine ("PT") experienced a catastrophic failure. An investigation into the cause of the failure identified several conditions that resulted in the failure. PW Power Systems ("PWPS"), the OEM, designed an upgrade to the equipment to lower the risk of a future failure.

A borescope inspection program to identify these conditions in the other PTs has successfully prevented additional failures. The pre-failure

conditions had been identified in PTs 19A and 11A through detailed borescope inspections, which confirmed the need to send both units to PWPS for upgrades and repairs. These repairs and upgrades greatly reduce the risk of catastrophic damage to the units. A failure of the PT unit could result in a loss of availability of 52 MW for 120 days. These projects completed the upgrades and returned the units to a reliable condition.

29. Q. WHAT WAS THE TOTAL COST OF THE PROJECTS?

A. The total plant in service for project CS2027 was $1,094,388 and CS2034 was $1,102,660, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The projects were prudently designed and constructed, and the costs of the projects were prudently incurred. The total project cost for CS2027 was $1,109,258, excluding AFUDC, and was estimated at $1,092,233, excluding AFUDC. The total project cost for CS2034 was $1,146,133, excluding AFUDC and was estimated at $1,092,223, excluding AFUDC.

2. CS2153 – Clark Peakers Replacement of Stack Expansion Joints

30. Q. PLEASE DESCRIBE THE CLARK PEAKING UNITS STACK EXPANSION JOINT REPLACEMENT PROJECT AND WHY IT WAS NECESSARY.

A. The 12 Clark PWPS Swift Pac Peaking Units were all placed in service in 2008 and have approximately the same operating run hours. The existing Selective Catalytic Reduction ("SCR") system to stack exhaust expansion joints was failing due to cracks in the internal duct flow liner and frame, allowing the hot gasses to deteriorate the expansion joint insulation and

the external expansion joint belt material. All the exhaust expansion joints were showing visible external deterioration and were starting to leak exhaust gases. This project was required by the unit's air permit due to the leakage.

The scope of work for the project was to replace leaking exhaust SCR to Stack expansion joints on the 12 peaking units and replace or repair the cracked flow liners and frames to restore the expansion joint integrity.

31. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?

A. The total plant in service for project CS2153 was $1,133,409, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the costs of the project were prudently incurred. The total project cost was $1,132,896, excluding AFUDC, and was estimated at $1,731,316, excluding AFUDC.

3. CS2201 and CS2202 – Clark Units 5 and 6 Hot Gas Path Inspection

32. Q. PLEASE DESCRIBE THE CLARK UNITS 5 AND 6 HOT GAS PATH PROJECTS AND WHY THEY WERE NECESSARY.

A. Clark Units 5 and 6 are Siemens/Westinghouse 501B6-DNL Gas Turbines that were installed in 1979 and in 2008, the Dry Low NOx LEC III conversion parts were installed, which was the last major turbine maintenance on the units. By January 1, 2021, Clark Unit 5 had 1,184 starts since the 2008 modifications were completed and Clark 6 had 1,220 starts. PSM, who is the manufacturer of the installed combustion system,

originally recommended maintenance intervals of 400 starts for a combustion inspection and 800 starts for a hot gas path inspection. Since Clark Units 5 and 6 are not covered by an OEM LTSA, the Company continually monitors the performance of the units, performs periodic inspections, and adjusts the combustion inspection and hot gas path inspection outages intervals accordingly. The risk of a forced outage, as well as the cost and duration of the forced outage, increases as the number of starts increases. Based on a risk evaluation, the probability that the units would incur a major combustion component failure resulting in a high cost and duration outage has increased to the point the hot gas path outage was necessary. Generally, the full scope of a hot gas path inspection includes the combustion system components and a detailed inspection of the turbine nozzles, shrouds, blades and buckets, bearings, rotor, cross-fire tubes, fuel nozzle sets, and the turbine casing.

33. Q. WHAT WAS THE TOTAL COST OF THE PROJECTS?

A. The total plant in service for project CS2201 was $983,099 and CS2202 was $1,429,072, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The projects were prudently designed and constructed, and the costs of the projects were prudently incurred. The total project cost for CS2201 was $971,755, excluding AFUDC, and was estimated at $1,086,408, excluding AFUDC. The total project cost for CS2202 was $1,424,105, excluding AFUDC, and was estimated at $1,086,407, excluding AFUDC.

4. CS2223 – Clark Peakers Fuel Gas Control Valves and Drivers

34. Q. PLEASE DESCRIBE THE CLARK PEAKING UNITS FUEL GAS CONTROL VALVES AND DRIVERS REPLACEMENT PROJECT AND WHY IT WAS NECESSARY.

A. The Clark Peaking Units experienced three fuel gas control valve failures in less than a year. These failures occurred on Unit 21 B in October 2019, Unit 22 A in May of 2020, and Unit 18 B in July of 2020. In July 2020, PWPS issued Service Bulletin SB-FT8-19M03 addressing these fuel gas control valves. NV Energy was subsequently notified that due to current trends leaning towards failure and the replacement of the existing fuel gas control valves together with the Digital Driver (EM24) end of life failures, the vendor will no longer service or have inventory of the obsolete equipment but will have upgraded fuel gas control valves and upgraded digital valve positioner retrofit kits available. Therefore, the replacement of the existing obsolete fuel gas control valves and drivers with the newly upgraded valves and drivers was required.

The poor reliability of the fuel gas control valves could result in the loss of a unit, or possibly multiple units, for a 20-week period in the event of a forced outage.

The scope of work for this project included retrofits to all 12 of the Clark Plant Peaking units. The work on each unit included:

- Engineering design and Project Management services for implementing the upgraded system.
- Retrofit the EM-24 digital Drivers with the Digital Valve Positioners ("DVP").
- Replace Gas Modulating Valves.

- Revise the Unit Controls and Human Machine Interface ("HMI") software to incorporate the addition of the new DVP.

Update and provide the Technical Documentation affected by the DVP upgrade.

35. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?

A. The total plant in service for project CS2223 was $1,465,956 including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the costs of the project were prudently incurred. The total project cost was $1,473,406, excluding AFUDC, and was estimated at $1,528,895, excluding AFUDC

5. CS2238 – Clark Peakers Generator Capital Spare Purchase

36. Q. PLEASE DESCRIBE THE CLARK PEAKING UNITS GENERATOR CAPITAL SPARE PURCHASE PROJECT AND WHY IT WAS NECESSARY.

A. Clark has a fleet of 12 FT8 Swift Package Units specifically designed to operate during peak electrical demand periods. The equipment was installed in 2008 with some of the units approaching 5,300 hours of operation and 1,500 unit starts. The risk of a significant failure of the generator is increasing.

Each of FT8 Swift Package Units has 2 GG8-3 Gas Generators that drive a single generator on a common shaft. The failure or unavailability of one of the generators will result in the loss of 52 MW. Lead time on a replacement generator is typically 45 weeks.

This project provided for the purchase of a rotatable capital spare PWPS GG8-3 Generator that is usable on any of the 12 peaking units. The availability of the spare component reduces the risk of lost generation during high demand periods.

37. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?

A. The total plant in service for project CS2238 was $2,116,649 including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the costs of the project were prudently incurred. The total project cost was $2,063,763, excluding AFUDC, and was estimated at $1,839,276, excluding AFUDC. The additional project costs resulted from the need to install a climate-controlled area within the Clark Station warehouse to accommodate the generator.

6. CS2251 – Clark Peakers Duct Bus Rebuild

38. Q. PLEASE DESCRIBE THE CLARK PEAKING UNITS DUCT BUS REBUILD PROJECT AND WHY IT WAS NECESSARY.

A. The 12 PWPS FT8-3 units at the Clark are divided into three Power Blocks, with one Generator Step-Up Transformer ("GSU") for each power block. Each Power Block GSU supports the electrical output of four PWPS FT8-3 generators. The 13.8 kV - 3000A non-segregated bus ducts are used to electrically connect each PWPS FT8-3 unit's generator to their respective Power Block's GSU transformer. High voltage electrical failures of the bus duct have occurred resulting in forced outages. Each failure resulted in the loss of 312 MW for an average of 10 days to restore

the electrical integrity of the bus duct. The failures occurred in December 2020 on Power Block 3, May 2019 on Power Block 2, and February 2015 on Power Block 2.

Failure analysis of each event showed the insulation on the solid copper bus was failing due to corona deterioration within the enclosed 13.8 kV 3000 Amp non-segregated bus duct at the bus bar supports. The progressive deterioration of the original bus bar insulating material resulted in a phase-to-phase and phase-to-ground electrical fault or high voltage flash at the supports.

The scope of work for this project was the disassembly, cleaning, inspection, reconditioning, and replacement of the damaged non-segregated bus bar's insulation and bus supports, and the testing and reassembly of the bus ducts. The result was to restore the three Power Blocks 13.8 kV - 3000A non-segregated bus ducts to their original designed electrical integrity to mitigate any future bus duct related outages.

39. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?

A. The total plant in service for project CS2251 was $2,422,891 including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the costs of the project were prudently incurred. The total project cost was $2,424,439, excluding AFUDC, and was estimated at $2,480,840, excluding AFUDC.

7. CS2286(18B), CS2317(20B), CS2344(15B), CS2348(22B), CS2351(20A), CS2352(18A), CS2361(21A) and CS2368(19A) – Clark Peaker Gas Generator Rebuilds

40. Q. PLEASE DESCRIBE THE CLARK PEAKING UNITS GAS GENERATOR REBUILD PROJECTS AND WHY THEY WERE NECESSARY.

A. As stated above, Clark consists of 12 FT8 Swift Package Turbine Units, each unit producing 52 MW. The FT8 Swift Package unit uses two GG8-3 Gas Generators to turn a single generator. Each unit's gas generator is coupled to the electrical generator by a power turbine. The power turbine transfers the hot gas energy from the gas generator into rotating power to turn the generator. When failure of the gas generator is detected or determined through inspection, the gas generator is removed from the unit and replaced with a rotatable spare gas generator. The damaged gas generator is shipped to the PWPS factory for further inspection and repair. These projects cover repairs to a number of different gas generators over the test period. The costs of these projects vary by the extent of the repairs necessary to return them to service.

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41. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?

A. The total plant in service recorded as of the end of the Test Period for these projects is shown in the **Table Lescenski-Direct-2**:

Table Lescenski-Direct-2

Budget ID	Unit	Estimate (Without AFUDC)	Actual Cost (Without AFUDC)	Total Plant in Service (Including AFUDC
CS2286	Unit 18B	$1,994,343	$ 2,124,171	$ 2,118,119
CS2317	Unit 20B	$ 2,916,194	$ 2,925,889	$ 2,901,481
CS2344	Unit 15B	$ 2,858,295	$ 2,425,198	$ 2,410,921
CS2348	Unit 22B	$ 2,087,154	$ 1,838,559	$ 1,831,796
CS2351	Unit 20A	$ 2,973,225	$ 2,675,907	$ 2,728,633
CS2352	Unit 18A	$ 2,949,430	$ 2,776,025	$ 2,778,814
CS2361	Unit 21A	$ 979,992	$ 946,921	$ 946,921
CS2368	Unit 19A	$ 979,992	$ 988,121	$ 987,575

8. CS2346 – Clark Peaker Capital Spare Gas Generator

42. Q. PLEASE DESCRIBE THE CLARK PEAKERS CAPITAL SPARE GAS GENERATOR PROJECT AND WHY IT WAS NECESSARY.

A. Clark has 12 FT8 Swift Pac units, with each Swift Pac having two gas generators (GG8), which are aero derivative combustion gas turbines that drive a single 52 MW generator. The average rebuild turnaround time for a failed/failing GG8 is 90 or more days. Clark currently has one spare GG8 that serves as rotatable spare. This rotatable spare has been utilized five times, saving an estimated 450 days of unit unavailability, three of which were in 2021.

This project procured an additional spare gas generator to mitigate the risk and expense of an unavailable unit due to failure. Having this spare on hand and available during a failure event will greatly reduce the risk of

exposure to costly extended periods of time that would be necessary to remove, rebuild, and replace a failed unit.

43. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?

A. The total plant in service for project CS2346 was $6,292,418 including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the costs of the project were prudently incurred. The total project cost was $6,292,418, excluding AFUDC, and was estimated at $6,512,935, excluding AFUDC.

C. HARRY ALLEN STATION

1. HA2153 – Combustion System Capital Parts Replacement

44. Q. PLEASE DESCRIBE THE HARRY ALLEN COMBUSTION SYSTEM CAPITAL PARTS REPLACEMENT PROJECT AND WHY IT WAS NECESSARY.

A. Harry Allen Unit 4 has operated through approximately 1,020 fired starts since its last maintenance outage in 2012. The extended wear and tear on the combustion parts was making it difficult to maintain environmental compliance during startups and operations.

The unit has seen increased usage since the plant started participating in the Energy Imbalance Market ("EIM"). With more renewable energy entering the grid, reliance on fast start units for peak support is in increasing demand. To remain reliable and environmentally compliant, Unit 4 required the combustion inspection and hot gas path overhaul as

prescribed by the manufacturer. The primary benefit of an inspection and overhaul was to ensure the unit remains environmentally compliant during unit startups and operations.

The scope of this project was to complete an equipment manufacturer prescribed combustion inspection and hot gas path overhaul on Harry Allen Unit 4 during the spring 2022 planned outage. The project is a component of Master General Services Contract with GE. The specific scope for the hot gas path overhaul included the following:

- Replacement of combustion parts (primary and secondary fuel nozzles, crossfire tubes, bull horns, liners, and TPs and associated hardware)
- Replacement of Stage 1 Buckets and associated hardware

  Replacement of Stage 1 Nozzle and associated hardware

45. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?

A. The total plant in service for project HA2153 was $2,858,703, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The projects were prudently designed and constructed, and the costs of the projects were prudently incurred. The total project cost was $2,683,241, excluding AFUDC, and was estimated at $2,608,093, excluding AFUDC.

2. HA2190 and HA2191 – Harry Allen 3 and 4 Wet Compression

46. Q. PLEASE DESCRIBE THE HARRY ALLEN UNITS 3 AND 4 WET COMPRESSION PROJECTS AND WHY THEY WERE NECESSARY.

A. Harry Allen Units 3 and 4's CTs required the installation of a wet compression system in order to provide additional generating output (MW), operational flexibility, and increased efficiency during the peak summer operating season. During hot weather (peak summer operating) periods, a CT's overall power output and efficiency decreases, leading to increased fuel consumption (heat rate) and emissions. The installation of a wet compression system provides a cost effective and energy efficient means to increase the unit's output during hot weather. Wet compression is accomplished by spraying water in the form of a fog to fully saturate the inlet air. The excess fog droplets are carried into the CT's compressor where they evaporate and produce an intercooling effect. This intercooling effect reduces the energy consumed by the compressor and allows for more power to be available at the output shaft of the turbine.

Fogging the inlet air increases the output and efficiency of the combustion turbine. MeeFog wet compression systems consist of a high-pressure pump skid (2000 psi) that delivers high-pressure water via stainless steel feedlines to an array of fogging nozzles located in the combustion turbine inlet air duct. The expected power output increase is 7 MW per unit, for a station increase of 14 MW.

47. Q. WHAT WAS THE TOTAL COSTS OF THE PROJECTS?

A. The total plant in service recorded for project HA2190 was $2,292,461, including AFUDC. The total plant in service for HA2191 was $2,240,591, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The projects were prudently designed and constructed, and the costs of the projects were prudently incurred. The total project cost for HA2190 was $2,231,606, excluding AFUDC, and was estimated at $3,684,528, excluding AFUDC. The total project cost for HA2191 was $1,618,244, excluding AFUDC, and was estimated at $2,608,093, excluding AFUDC.

When the project costs were estimated, the Company expected to encounter similar discovery work as was recently experienced during wet compression projects at other generating sites. The projects did not encounter significant discovery work, and therefore, resulted in lower project costs than estimated.

3. HA2206 – Harry Allen 4 Generator Rewind

48. Q. PLEASE DESCRIBE THE HARRY ALLEN 4 GENERATOR REWIND PROJECT AND WHY IT WAS NECESSARY.

A. Electrical testing in December of 2021 discovered the existence of a condition called "Spark Erosion," which coupled with loose wedges (highly probable given the unit's 16 years of service), will cause the winding insulation to break down resulting in a short or ground of the generator windings. This would likely cause a catastrophic failure and severe damage to the generator. The best option was to restore the integrity of the winding insulation by replacing the windings, also

providing an opportunity to replace loose wedges. This eliminated the likelihood of a short or ground fault which would lead to a catastrophic failure and severe damage of the generator.

49. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?

A. The total plant in service for project HA2206 was $1,199,520, including AFUDC was included in the calculation for this filing. The total project costs that will be corrected in the certification filing and are currently recorded at $3,650,017, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The projects were prudently designed and constructed, and the costs of the projects were prudently incurred. The total project cost was $3,592,628, excluding AFUDC, and was estimated at $4,315,060, excluding AFUDC.

D. LAS VEGAS GENERATING STATION

1. LC2177 – Ovation DCS Installation

50. Q. PLEASE DESCRIBE THE OVATION DCS INSTALLATION PROJECT AND WHY IT WAS NECESSARY.

A. The units at LVGS were operating on disparate DCS platforms. The multiple distinct operating platforms made it extremely difficult to maintain the system's cyber security, maintenance, and operating integration needs. The Power Block ("PB") 2, 3 CTs and the Unit 1 Steam Turbine ("ST") units were operating on a version of Emerson's Ovation. The Unit 1 ST, the PB2 and 3 STs, and the balance of plant equipment were operating on a Rockwell's PlantPAX Control system. The PlantPAX

Control System was not capable of meeting the current Company cyber-security standards and was required to be either upgraded or replaced.

The Company is migrating to a fleet standard of an Emerson Ovation system to ensure it has a patchable (cyber-security) capability, satisfying the current Company cyber-security standards, and is compliant with the Companies' Vulnerability Management Program ("VMP"). The Companies have implemented a policy and practice to maintain systems that can be part of a robust VMP. The VMP requires a system that is patchable (security) and robust enough to scan for vulnerabilities and be patched without compromising operational reliability. Similar projects were presented to and approved by the Commission in Sierra's 2022 General Rate Case.

A significant benefit of upgrading the DCS is that the upgraded platform will be able to be properly maintained and patched to prevent a cyberattack on an operating unit. The new system will be supported by the OEM, there will be a readily available supply of replacement components to reduce outage time in the event of a failure, and the operations and maintenance personnel will have a single platform that is integrated throughout the station's systems and components. The project standardizes the station's control system with the Companies' fleet and inclusion in the VMP. This project also upgraded the Control Room infrastructure to allow the operators to operate the multiple CT and ST units through specifically (graphically) designed screens to visualize and process the station's operating systems on multiple dedicated monitors.

51. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?

A. The total plant in service for project LC2177 was $9,320,990, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the cost of the project was prudently incurred. The total project cost was $8,541,069, excluding AFUDC, and was estimated at $9,375,197, excluding AFUDC.

E. SILVERHAWK GENERATING STATION

1. SH2036 – CTB Rotor Replacement

52. Q. PLEASE DESCRIBE THE SILVERHAWK CT B ROTOR REPLACEMENT PROJECT AND WHY IT WAS NECESSARY.

A. Silverhawk maintains a Siemens 501F gas turbine in Combustion Turbine B ("CTB"). The gas turbine rotor has a design life of 100,000 hours and 3,600 starts. This gas turbine rotor would have reached its end of life in the spring of 2022, which is when industry practice recommends either the rotor be replaced, or an end-of-life inspection be completed. The replacement, or inspection, was necessary to ensure the continued availability and reliability of the gas turbine. Nearly 30 days are required for the "end of life" inspection to be completed at the OEM factory, where the OEM unstacks and inspects the rotor. Final results, which are required for the approval of another 100,000 hours of operation, can take an additional 60 days. Any anomalies found during the end-of-life inspection can easily reach expenditures of more than $2,000,000 for any necessary repairs.

Due to the long inspection times, and to minimize the risk of unexpected anomalies, 501F turbine maintenance providers offer a rotor exchange option. This option provides the customer with a rotor rated for 100,000 operating hours in exchange for the existing used rotor. The rotor exchange program is also beneficial in decreasing outage duration. The rotor can be exchanged quickly during a planned outage rather than the 30 or more days required for an end-of-life inspection.

53. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?

A. The total plant in service for project SH2036 was $4,797,483, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the cost of the project was prudently incurred. The total project cost was $4,917,134, excluding AFUDC, and was estimated at $5,500,424, excluding AFUDC.

2. SH2073 – SH Turbine Controls System Replacement

54. Q. PLEASE DESCRIBE THE SILVERHAWK TURBINE CONTROLS SYSTEM REPLACEMENT PROJECT AND WHY IT WAS NECESSARY.

A. Silverhawk utilized an ABB Control System to control the Balance of Plant systems and Siemens Teleperm XP control system to control two CTs. The CT control system was operating at close to its maximum capacity, was extremely difficult to program, had no local support, was difficult to integrate into the PI historian, and had the potential to shut down the plant for extended periods of time. Replacing the existing

platforms with an integrated DCS allows better controls integration, a single operator interface, an integrated alarm management system, integration of the plant PI historian, a single point of contact for technical and equipment support, and compliance with current cyber security standards.

The predominant issues with the prior two control systems revolved around the technical, operational, and commercial challenges of having separate control platforms. Each of the two systems were aged and beyond active support from the original manufacturer. Neither system complied with the Companies' corporate cyber-security standards. Each system required its own, compatible spare parts, unique operator training, and dedicated servers, workstations and displays with their own proprietary software. Long-term data logging to the PI historian had to be manually set up for each platform. There was limited communication between the platforms, alarming and data management was fragmented. Similar projects were presented to and approved by the Commission in Sierra's 2022 General Rate Case.

55. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?

A. The total plant in service for project SH2073 was $7,089,050, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the costs of the project were prudently incurred. The total project cost was $6,464,451, excluding AFUDC, and was estimated at $8,151,164, excluding AFUDC. The original estimate included new

fiberoptic cabling. The quantity of new fiberoptic cabling necessary was significantly lower than expected, leading to cost savings.

3. SH2089 and SH2093 – HRSG Liner Replacement

56. Q. PLEASE DESCRIBE THE SILVERHAWK HEAT RECOVERY STEAM GENERATOR ("HRSG") LINER REPLACEMENT PROJECTS AND WHY THEY WERE NECESSARY.

A. The Silverhawk HRSG's exterior casing is not rated to handle the hot flue gases. The original design included insulation and a liner plate to cover and protect the casing. The liner plates prevent the hot gases from coming in direct contact with the insulation. However, the liner plates started to fail, causing the insulation to degrade. The degraded insulation breaks into smaller pieces and plugs up the catalyst, which further results in high furnace pressure. The high furnace pressure could cause the HRSG duct to rupture and presents a significant safety hazard to the personnel at the plant. The liner plates degraded and failed once a year on average. When these fail, the plant needs to be shut down to make repairs to the liner and clean the catalyst. This project replaced the degraded liner to avoid these events.

57. Q. WHAT WAS THE TOTAL COST OF THE PROJECTS?

A. The total plant in service for project SH2089 was $1,495,794, including AFUDC. The total plant in service for project SH2093 was $1,366,290, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The projects were prudently designed and constructed, and the costs of the projects were prudently

incurred. The total project cost SH2089 was $1,480,877, excluding AFUDC, and was estimated at $1,833,250, excluding AFUDC. The total project cost for SH2093 was $1,354,436, excluding AFUDC, and was estimated at $1,833,250, excluding AFUDC.

4. SH2105 – Silverhawk Steam Turbine Major Overhaul

58. Q. PLEASE DESCRIBE THE SILVERHAWK STEAM TURBINE OVERHAUL PROJECT AND WHY IT WAS NECESSARY.

A. Silverhawk's ST was due for a major overhaul. Scheduled inspections and part replacements are required to maintain reliable operation of the steam turbine and generator. The replacement parts by GE allow for continued reliable operation of the turbine and generator. The replacement was necessary for capital turbine rotating and stationary blades, control valve parts, steam seals, and hydraulic actuators. The inspection included a generator Miniature Air Gap Inspection Crawler ("MAGIC") inspection and refurbishment. The work was completed during the planned outage in May 2022.

59. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?

A. The total plant in service for project SH2105 was $4,628,506, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the cost of the project was prudently incurred. The total project cost was $4,599,678, excluding AFUDC, and was estimated at $4,484,621, excluding AFUDC.

5. SH2117 and SH2118 – 17 MW 501F Combustion Turbine Upgrade

60. Q. PLEASE DESCRIBE THE SILVERHAWK 17 MW 501F COMBUSTION TURBINE UPGRADE PROJECTS AND WHY THEY WERE NECESSARY.

A. The 501F CT upgrades at Silverhawk CTA and CTB are financially favorable projects that add system benefit through reducing the peak open position and reducing market dependence as additional renewable generation is added. The upgrades help achieve an increase in the unit's megawatt output and improve the unit's efficiency through replacing multiple turbine components with an upgraded design.

The scope of work for the CT upgrades included replacing critical turbine components with upgraded components and the addition of auxiliary turbine systems. The Gas Turbine Optimization Package ("GTOP") upgrade package included upgrades to: (1) 16th stage compressor blades, (2) turbine stage 1, stage 2 and stage 4 components, and (3) the isolation ring. Additional operational flexibility improvements were gained through upgrading the combustion system, the addition of auxiliary systems and by modifying the turbine control system. Control system modifications were also required but are part of a separate cyber security controls upgrade project.

61. Q. WERE THESE PROJECTS PREVIOUSLY PRESENTED TO THE COMMISSION?

A. Yes. The upgrades to the Silverhawk CTs were presented to and approved by the Commission in the Companies' 2021 Joint IRP, Docket No. 21-

06001. The Commission approved these two projects in its Phase I Order on September 28, 2021.[1]

62. Q. WHAT WAS THE TOTAL COST OF THE PROJECTS?

A. The total plant in service for project SH2117 was $19,115,228, including AFUDC. The total plant in service for project SH2118 was $16,769,143, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The projects were prudently designed and constructed, and the costs of the projects were prudently incurred. The total project cost for SH2117 was $18,753,583, excluding AFUDC, and was estimated at $16,637,328, excluding AFUDC. The total project cost for SH2118 was $16,496,389, excluding AFUDC, and was estimated at $16,637,328, excluding AFUDC.

6. SH2232 – Silverhawk Combustion Turbine Wet Compression

63. Q. PLEASE DESCRIBE THE SILVERHAWK COMBUSTION TURBINE WET COMPRESSION PROJECT AND WHY IT WAS NECESSARY.

A. Nevada Power determined that additional capacity was available from the existing Silverhawk CTs through a wet compression system. The wet compression system provides additional generating output (MW), operational flexibility, and increased efficiency during the peak summer operating season. During hot weather (peak summer operating) periods, a CT's overall power output and efficiency decreases, leading to increased fuel consumption (heat rate) and emissions. The installation of a wet

[1] Docket Nos. 21-06001 & 21-06002, Phase 1 Order, Page 28

compression system provides a cost effective and energy efficient means to increase the unit's output during hot weather. Wet compression is accomplished by spraying water in the form of a fog to fully saturate the inlet air. The excess fog droplets are carried into the CT's compressor where they evaporate and produce an intercooling effect. This intercooling effect reduces the energy consumed by the compressor and allows for more power to be available at the output shaft of the turbine.

Fogging the inlet air increases the output and efficiency of the CT. Wet compression systems consist of a high-pressure pump skid (2000 psi) that delivers high-pressure water via stainless steel feedlines to an array of fogging nozzles located in the CT inlet air duct.

64. Q. WAS THE PROJECT PREVIOUSLY PRESENTED TO THE COMMISSION?

A. Yes. The wet compression upgrade to the Silverhawk CTs was presented to and approved by the Commission in the Companies' 2021 Joint IRP, Docket No. 21-06001. The Commission approved the project in its Phase I Order on September 28, 2021.[2]

65. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?

A. The total plant in service for project SH2232 was $7,435,469, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the cost of the project was prudently incurred. The total

[2] Docket Nos. 21-06001 & 21-06002, Phase 1 Order, Page 28

project cost SH2232 was $7,273,724, excluding AFUDC, and was estimated at $9,903,978, excluding AFUDC.

F. SUN PEAK GENERATING STATION

1. SK2023 – Sun Peak Unit 4 Hot Gas Path

66. Q. PLEASE DESCRIBE THE SUN PEAK UNIT 4 HOT GAS PATH PROJECT AND WHY IT WAS NECESSARY.

A. Sun Peak Unit 4 is one of three peaking units at the facility that went into service in 1991, with its Units 3 and 5. The unit has exceeded the 900 factored starts maintenance interval since the last combustion inspection and the 1,200 factored starts maintenance interval since its last major inspection (which included hot gas path components) was performed in March 2002.

On May 12, 2020, Sun Peak Unit 4 tripped off-line due to the "Overspeed Protection Bolt" activating after being online for around four hours. The turbine speed (RPM) telemetry did not indicate any increase in speed above 3,600 RPM, which is normal speed for the turbine. After the unit tripped, an oil leak alongside the shaft seal to gear box was discovered. The Company conducted an inspection following the trip and discovery of the leak.

A full borescope inspection and a lube oil analysis were conducted. The borescope inspection revealed a substantial amount of oil residue in the aft compressor (stage 17 stator Vane, Exit Guide Vanes 1 and 2). Unrelated to the trip, there was other major damage observed within the compressor

and combustion section. The lube oil analysis showed an elevated concentration of coarse metal iron (particles 20 to 70 microns) indicating gear, carrier, or shaft wear.

A hot gas path inspection was planned to occur in 2021, but due to the discovered damage, it was decided that the hot gas path work would be performed concurrently with the expected repairs, instead of conducting another outage a year later.

67. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?

A. The total plant in service for project SK2023 was $2,738,503, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the cost of the project was prudently incurred. The total project cost was $2,640,622, excluding AFUDC, and was estimated at $3,037,617, excluding AFUDC.

G. WALT HIGGINS GENERATING STATION

1. WH2163 – Combustion Turbine 2 Generator Exciter Replacement

68. Q. PLEASE DESCRIBE THE WALT HIGGINS COMBUSTION TURBINE 2 GENERATOR EXCITER REPLACEMENT PROJECT AND WHY IT WAS NECESSARY.

A. On June 21, 2020, Higgins Unit 2's generator incurred a failure in its exciter unit on the generator field. This generator uses a brushless exciter mounted to the field shaft at the front of the machine. The failure of the exciter impacted and damaged the generator field shaft.

Detailed inspections and tests were conducted upon extraction of the generator field and adjacent/interfacing components to determine what components required replacement, repairs, or restoration. The exciter and the generator field had visual damage. The root cause of the failure was a radial lead connection failure, resulting in overheating and eventual failure of the exciter and diodes.

69. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?

A. The total plant in service for project WH2163 was $1,262,570, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the cost of the project was prudently incurred. The total project cost was $1,262,570, excluding AFUDC, and was estimated at $1,307,116, excluding AFUDC.

2. WH2170 – CT 1 Compressor Diaphragms Replacement

70. Q. PLEASE DESCRIBE THE WALT HIGGINS COMBUSTION TURBINE 1 COMPRESSOR DIAPHRAGMS REPLACEMENT PROJECT AND WHY IT WAS NECESSARY.

A. The Higgins Unit 1 CT is a Siemens-Westinghouse 501F CT. The CTs have compressor sections with 16 stages of rotating blades and stationary diaphragm components. The blades and diaphragms alternate within the compressor section.

During the scheduled Unit 1 CT Planned (major) Outage in November 2020, an inspection of the compressor diaphragms (Rows 8, 9, 14, 15, and

16; and stationary blades) identified degradation and defects within these components. If the defects were not addressed, the issues identified would have led to a failure of these components and others within the CT and if the compressor diaphragms were to fail, consequential damage to downstream components (blades, vanes, etc.) would occur, which would lead to a catastrophic failure of the CT. In order to maintain the reliability of the CT, these components needed to be replaced

71. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?

A. The total plant in service for project WH2170 was $1,579,723, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the cost of the project was prudently incurred. The total project cost was $1,579,723, excluding AFUDC, and was estimated at $1,734,105, excluding AFUDC.

3. WH2171 – Wet Compression System Installation

72. Q. PLEASE DESCRIBE THE WALT HIGGINS WET COMPRESSION SYSTEM INSTALLATION PROJECT AND WHY IT WAS NECESSARY.

A. Similar to the wet compression project for the Silverhawk CTs, Nevada Power determined that additional capacity was available from the existing Higgins CTs through a wet compression system. As discussed above, the wet compression system provides additional generating output (MW), operational flexibility, and increased efficiency during the peak summer operating season. During hot weather (peak summer operating) periods, a

CT's overall power output and efficiency decreases, leading to increased fuel consumption (heat rate) and emissions. The installation of a wet compression system provides a cost effective and energy efficient means to increase the unit's output during hot weather. Wet compression is accomplished by spraying water in the form of a fog to fully saturate the inlet air. The excess fog droplets are carried into the CT's compressor where they evaporate and produce an intercooling effect. This intercooling effect reduces the energy consumed by the compressor and allows for more power to be available at the output shaft of the turbine.

Fogging the inlet air increases the output and efficiency of the CT. Wet compression systems consist of a high-pressure pump skid (2000 psi) that delivers high-pressure water via stainless steel feedlines to an array of fogging nozzles located in the CT inlet air duct.

73. Q. WHAT WAS THE TOTAL COST OF THE PROJECT?

A. The total plant in service for project WH2171 was $9,274,060, including AFUDC. All the facilities installed are in service and used and useful in the provision of utility service. The project was prudently designed and constructed, and the cost of the project was prudently incurred. The total project cost was $9,239,013, excluding AFUDC, and was estimated at $9,031,711, excluding AFUDC.

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SECTION 4. LONG-TERM MAINTENANCE OR SERVICE AGREEMENTS

74. Q. PLEASE DESCRIBE THE LTSA OUTAGE CAPITAL COSTS.

A. The LTSAs are multi-year agreements covering the Lenzie, Harry Allen, Silverhawk and Higgins F-class combined cycle units. The LTSAs were established to assure reliability of the large-combined cycle turbines and generators while levelizing maintenance expenses over the term of the agreements. The LTSAs provide for full inspection, replace and repair coverage of the CTs and inspections only for the compressors, generators and steam turbines. Needed repairs to the compressors, generators and steam turbines are not covered in the LTSA hourly fee and are considered extra work. These agreements have been discussed in rate cases for both Companies, specifically for Sierra in Docket Nos. 10-06001, 13-06002, 16-06006, 19-06002 and 22-06014, and for Nevada Power in Docket Nos. 11-06006, 14-05004, 17-06003 and 20-06003. All quarterly, annual and milestone costs associated with LTSAs are allocated between O&M expense and prepaid capital according to a contract-specific predetermined allocation. Journal entries are posted for each outage to transfer the prepaid capital to construction work in progress/plant in service based on a historical capital ratio (by outage type) and overall prepaid capital expected for the agreements.

75. Q. WERE THE LTSAS AND SUBSEQUENT OUTAGE PROJECTS PREVIOUSLY APPROVED BY THE COMMISSION?

A. Yes. The LTSA costs and accounting methodologies for the LTSA have been reviewed and approved by the Commission in the above-noted dockets. There have been no changes to the current LTSAs or accounting

since the Commission orders in Docket Nos. 14-05004 (Nevada Power) and 16-06006 (Sierra).

76. Q. WHAT ARE THE COSTS OF THE LTSA OUTAGE PROJECTS?

A. **Table Lescenski-Direct-3** below presents the total cost of the LTSA outage projects for the period through the end of the test year and estimates through the end of the certification period.

Table Lescenski-Direct-3

LTSA Outage Capital through the end of the Test Period

Budget ID	Plant	Outage Type	Plant in Service
CL1103	Lenzie	2021	$ 18,288,061
CL1104	Lenzie	2020	$ 17,956,536
SH1104	Silverhawk		$ 10,018,353
SH2189	Silverhawk	CT Hot Gas Path	$ 6,621,577
WH1059	Higgins		$ 16,695,459

LTSA Outage Capital through the end of the Certification Period

Budget ID	Plant	Outage Type	Plant in Service
HA1089	Harry Allen		$ 16,727,587

<u>SECTION 5. GENERATION INVESTMENT BETWEEN JANUARY 1, 2023, AND MAY 31, 2023.</u>

77. Q. HOW HAVE YOU ORGANIZED THIS SECTION OF YOUR TESTIMONY, WHICH ADDRESSES THE PROJECTED INVESTMENT IN GENERATION ASSETS DURING THE CERTIFICATION PERIOD?

A. Nevada Power is completing major investments in its generation fleet during the Certification Period. In order, I discuss investment at:

A. Lenzie
1. CL2127 LZ PB2 Balance of Plant Controls
   CL2128 LZ PB1 Balance of Plant Controls

B. Clark
1. CS2203 Clark Unit 7 – CT – Hot Gas Path Overhaul
2. CS2221 Clark 4-10 DCS Upgrade
3. CS2263 CK PKRS – Power Turbine EGT Upgrades
4. CS2336 CK Peaker Wet Compression System
5. CS2387 CK – Unit 12 A – Gas Generator
CS2388 CK – Unit 12 B – Gas Generator
CS2393 CK – Unit 20 B – Gas Generator

C. Harry Allen
1. HA1050 HA CC Steam Turbine Major Overhaul
2. HA2090 HA CT 5 22 MW 7F Upgrade
HA2091 HA CT 6 22 MW 7F Upgrade
3. HA2155 HA3 Combustion System Capital Parts Replacement
4. HA2160 HA Guard House, Entrance Gate and Security Cameras
5. HA2175 ACC Fan Blade Replacement (2022)
HA2176 ACC Fan Blade Replacement (2023)

D. LVGS
1. LC2233 PB 2 Cooling Tower Overhaul
LC2234 PB 3 Cooling Tower Overhaul

E. Sun Peak
1. SK2042 SK Units 3-5 Ovation Control System Update

H. CERTIFICATION – CHUCK LENZIE STATION

1. CL2127 and CL2128 -LZ PB1 and PB2 Balance of Plant Controls

78. Q. PLEASE DESCRIBE THE CHUCK LENZIE BALANCE OF PLANT CONTROLS PROJECTS AND WHY THEY WERE NECESSARY.

A. The Lenzie Balance of Plant systems include the water treatment system, the chiller systems, the duct burner systems, the Nalco water chemistry systems, and the auxiliary boiler systems. Each of these systems had separate, individual, and independent control systems, each were supported by different manufacturers, and all were spread across differing generations of technology. These systems were aged and could not be kept in conformity with the Companies' current business and cyber-security standards.

Combining the five systems under one DCS provides significant benefit to Lenzie including the following:

- A single control system rather than numerous, independent systems.
- One service/maintenance agreement to manage rather the four separate agreements.
- Technicians will no longer require training on several different systems.
- The Monitoring and Diagnostic Center will have access to provide technical support.
- Plant operators will have access to all auxiliary control systems.
- Reliability due to replacement with more current, state-of-the-art systems.
- Cyber security standards met throughout all the Balance of Plant systems.

Other simultaneous projects, like the update of the GE Turbine Control and replacement of the DeltaV Control System, in addition to this project, required a major reconfiguration to the existing Control Room layout and infrastructure. This project adds greater functionality, versatility, protection, visibility, and uniformity to the Lenzie Balance of Plant Control systems. Similar projects were presented to and approved by the Commission in Sierra's 2022 General Rate Case.

79. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THESE PROJECTS?

A. The current estimated cost of completion for project CL2127 is $10,333,979, including AFUDC and for CL2128 is $8,110,177, including AFUDC. Both projects will be in service before May 31, 2023.

As described in Q&A 23 above, project CL2127 was mistakenly closed into plant in service prior to December 31, 2022 and is included in the Test Period costs as well as the Certification Period estimates. This will be corrected in the Companies' certification filing in this Docket.

I. CERTIFICATION – CLARK GENERATING STATION

1. CS2203 – Clark Unit 7 Hot Gas Path Overhaul

80. Q. PLEASE DESCRIBE THE CLARK UNIT 7 HOT GAS PATH OVERHAUL PROJECT AND WHY IT WAS NECESSARY.

A. This project is similar to the two other Clark hot gas path projects discussed earlier for Clark 5 and 6, in Q&A 33. As of December 8, 2022, Unit 7 had 1,573 starts since the last maintenance outage/inspection. PSM, the manufacturer of the installed combustion system, originally recommended maintenance intervals of 400 starts for a combustion inspection and 800 starts for a hot gas path inspection. Since 800 starts is the recommended interval for the hot gas path inspection, exceeding this interval compounds the risk of a forced outage. The risk of a forced outage, as well as the cost and duration of the forced outage, will grow for each 100 starts beyond the recommended 800 starts for a hot gas path inspection. Nevada Power manages this risk through periodic borescope

inspections to determine when outage work is necessary. This outage will restore the unit to normal operating condition.

81. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THIS PROJECT?

A. The current estimated cost of completion is $1,623,674, including AFUDC, and the project will be in service before May 31, 2023.

2. CS2221 – Clark Units 4-10 DCS Upgrade

82. Q. PLEASE DESCRIBE THE CLARK UNITS 4-10 DCS UPGRADE PROJECT AND WHY IT WAS NECESSARY.

A. This project will update the control system on Clark units 4 through 10. The existing control system is a decade out of date. Operating systems no longer have security patches made, HMI and server hardware is no longer available, and the input/output (I/O) devices are no longer manufactured or sold through available channels. With these challenges, the system security patching cannot occur, and the cyber-security profile cannot be maintained, as required by the Companies' cyber-security standards. Reliability is also adversely affected with the current system as parts continue to become scarcer over time. This project will provide a newly updated and secure control system for these units, replace the aging and failing HMIs and servers and replace the aging and failing I/O devices in the system. Similar projects were presented to and approved by the Commission in Sierra's 2022 General Rate Case.

83. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THIS PROJECT?

A. The current estimated cost of completion is $9,748,993, including AFUDC, and the project will be in service before May 31, 2023.

3. CS2263 – Clark Peakers Power Turbine EGT Upgrades

84. Q. PLEASE DESCRIBE THE CLARK PEAKERS POWER TURBINE EGT UPGRADES PROJECT AND WHY IT WAS NECESSARY.

A. The Exhaust Gas Temperature ("EGT") probe upgrade, as outlined in the service bulletin SB-FT8-15M06, is designed to address the durability issues experienced with the current EGT probe (P/N 1082126) in FT8 gas turbine units. The new EGT probe (CT118700-1) incorporates a single channel design and improved mating harnesses that offer enhanced performance and lifespan.

This upgrade is beneficial for the maintenance and operation of FT8 gas turbine units. The primary reason for this upgrade is that the current EGT probe lacks the desired life expectancy and durability to support the FT8 fleet. Failures have been attributed to shortcomings in the tip and stud designs of EGT probe P/N 1082126. By replacing the existing probe with the new CT118700-1 design, the upgraded probe becomes more robust, resulting in increased longevity and better performance. The new EGT probes will require new harnesses, and the existing probe P/N 1082126 will be phased out once spares are exhausted. Overall, the EGT probe and harnesses upgrade offers enhanced reliability and durability, improving the efficiency and effectiveness of the affected gas turbine units.

85. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THIS PROJECT?

A. The current estimated cost of completion of $2,409,520, including AFUDC, was included in the Certification Period estimates based on the plan to complete this work in the spring of 2023. However, due to parts availability, this project will not be completed prior to May 31, 2023, and will be removed from the plant in service estimates when the certification filing is completed later in this Docket.

4. CS2336 – Clark Peakers Wet Compression System

86. Q. PLEASE DESCRIBE THE CLARK PEAKERS WET COMPRESSION SYSTEM PROJECT AND WHY IT WAS NECESSARY.

A. This project is similar to the wet compression upgrades that were discussed above for other units. Clark's 12 Pratt & Whitney FT8-3 Swift Pacs, Units 11-22, gas generators will be upgraded with a wet compression system in order to provide additional generating output (MW), operational flexibility and increased efficiency during the peak summer operating season. The expected power output increase is 3.77 MW/unit, with an expected guaranteed performance increase of 7.25 percent per unit or 45.24 MW increase for the 12 units at 112 degrees F at 10 percent relative humidity. This upgrade will allow the Nevada Power's generating system to benefit from a reduction of the open position and increased operational flexibility as additional generating demands are imposed upon the system during peak summer operating (hot weather) periods.

87. Q. WAS THIS PROJECT PREVIOUSLY PRESENTED TO THE COMMISSION?

A. Yes. This project was presented to the Commission in Docket No. 22-03024, but due to the timing of the project, the Companies did not request approval.

88. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THIS PROJECT?

A. The current estimated cost of completion is $20,219,551, including AFUDC, and the project will be in service before May 31, 2023.

5. CS2387, CS2388 and CS2393 – Clark Peakers Gas Generator Overhaul

89. Q. PLEASE DESCRIBE THE CLARK PEAKERS GAS GENERATOR OVERHAUL PROJECTS AND WHY THEY WERE NECESSARY.

A. This project is similar to the other gas generator overhauls discussed above, in Q&A 41. The FT8 Swift Pac unit uses two GG8-3 gas generators to turn a single generator. Each unit's gas generator is coupled to the electrical generator by a power turbine. The power turbine transfers the hot gas energy from gas generator into rotating power to turn the generator. When failure is detected or determined through inspection, the gas generator is removed from the unit and replaced with a rotatable spare gas generator. The damaged gas generator is shipped to the PWPS factory for further inspection and repair. These projects cover repairs to Units 12A, 12B and 20B, during the certification period. The costs of these projects vary by the extent of the repairs necessary to return them to service. The

repairs to the gas generators ensure that they will be able to reliably operate when needed to support customer needs.

90. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THESE PROJECTS?

A. The current estimated cost of completion for the projects is $2,933.617 (CS2387), $2,936,064 (CS2388) and $2,970,622 (CS2393), including AFUDC, and the CS2387 and CS2388 projects will be in service before May 31, 2023. The CS2393 project was delayed and will not be completed prior to May 31, 2023, and will be removed from the plant in service calculations in the certification filing in this Docket.

J. CERTIFICATION – HARRY ALLEN GENERATING STATION

1. HA1050 – Harry Allen Combined Cycle Steam Turbine Overhaul

91. Q. PLEASE DESCRIBE THE HARRY ALLEN COMBINED CYCLE STEAM TURBINE OVERHAUL PROJECT AND WHY IT WAS NECESSARY.

A. The Harry Allen Combined Cycle Steam Turbine was scheduled for an overhaul due to its operating hours. ST outages are planned for every 32,000 hours of operation to replace worn or damaged capital components. Components such as rotating and stationary blades, valve parts, steam seals, etc. that may be identified as requiring replacement through both borescope and internal inspection of the steam turbine during the planned outage.

Prior to the outage, the following was identified as meeting the replacement or refurbishment parameters and requirements:

- N1 Packing Rings

- 6 Shaft Bearings
- Main Steam Stop Valve Actuator
- Main Steam Control Valve Actuator
- Reheat Stop Valve Actuator
- Reheat Control Valve Actuator
- Valve Actuator and Trip Valve

The ST is a key component for maintaining the efficiency of the combined cycle as a whole. Losing the steam turbine would render the combined cycle unit inefficient and unreliable. If a steam turbine would experience a component failure during operations, an extended, unscheduled outage would be required to make repairs. The scheduled outage of 2023 is of sufficient time to complete the major overhaul.

92. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THIS PROJECT?

A. The current estimated cost of completion is $1,185,767, including AFUDC, and the project will be in service before May 31, 2023.

2. HA2090 and HA2091 – Harry Allen CT 5 and 6 22 MW 7F Upgrade

93. Q. PLEASE DESCRIBE THE HARRY ALLEN CT 5 AND 6 22 MW 7F UPGRADE PROJECTS AND WHY THEY WERE NECESSARY.

A. These projects are similar to the project discussed above for the Chuck Lenzie CTs, in Q&A 20. The 7FA upgrades are financially favorable projects that will add system benefit through reducing the peak open position and reducing market dependence as additional renewable generation is added. The upgrades will help achieve an increase in the unit's MW output and will improve the unit's efficiency through replacing the following turbine components with an upgraded design: (a)

compressor stage zero stationary and rotating blades, (b) combustion system components, and (c) turbine stage 1, stage 2 and stage 3 components. Additional operational flexibility improvements will be provided through upgrading the combustion system, the addition of auxiliary systems and by modifying the turbine control system.

94. Q. WERE THESE PROJECTS PREVIOUSLY PRESENTED TO THE COMMISSION?

A. Yes. The upgrades to the Harry Allen Combined Cycle (CT5 – HA2090 and CT6 HA2091) were presented to and approved by the Commission in the Companies' 2021 Joint IRP, Docket No. 21-06001. The Commission approved these two projects in its Phase III Order on December 28, 2021.[3]

95. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THESE PROJECTS?

A. The current estimated cost of completion is $23,840,082 (HA2090) and $31,015,777 (HA2091), including AFUDC, and the projects will be in service before May 31, 2023.

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[3] Docket No. 21-06001, March, 8, 2022, Corrected Modified Final Order, p. 47, para. 107.

3. HA2155 – Harry Allen Unit 3 Combustion Turbine Parts Replacement

96. Q. PLEASE DESCRIBE THE HARRY ALLEN UNIT 3 COMBUSTION TURBINE PARTS REPLACEMENT PROJECT AND WHY IT WAS NECESSARY.

A. The last maintenance outage and overhaul for the combustion system on Harry Allen Unit 3 was performed in May 2018. The combustion system parts (primary and secondary fuel nozzles, combustion liners, and transition pieces) were replaced at that time. Since May 2018, the combustion parts have run for approximately 670 starts. This is beyond the OEM's recommended maintenance interval of 450 starts. The hot gas path parts scheduled for replacement (Stage 1 Buckets, Stage 1 Nozzles, and Stage 1 Shrouds) have not been replaced in the unit's history. These parts have approximately 1,494 starts, which is over the OEM's recommended maintenance interval of 900 starts. The Stage 2 Shrouds require replacement based on recent borescope inspection findings. Nevada Power manages the risk and maintenance intervals through borescope inspections to determine the appropriate time to complete maintenance and capital replacement and adjust the OEM starts accordingly.

Unit 3 has seen increased usage since the plant started participating in the EIM. With more renewable energy entering the grid, reliance on fast start units for peak support is in growing demand. To remain reliable and environmentally compliant the unit needs the combustion and hot gas path system overhauled to achieve optimal operating efficiency.

97. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THIS PROJECT?

A. The current estimated cost of completion of $2,685,328, including AFUDC, was included in the Certification Period estimates based on the plan to complete this work in the spring of 2023. However, due to parts availability, this project will not be completed prior to May 31, 2023, and will be removed from the plant in service estimates when the certification filing is completed later in this Docket.

4. HA2160 – Harry Allen Guard House, Entrance Gate and Security Camera Replacement

98. Q. PLEASE DESCRIBE THE HARRY ALLEN GUARD HOUSE, ENTRANCE GATE AND SECURITY CAMERA REPLACEMENT PROJECT AND WHY IT WAS NECESSARY.

A. This project replaces the Harry Allen guard house, security cameras, and entrance gate to increase the reliability and dependability of the plant's security infrastructure and to ensure that the facility remains in compliance with the North American Electric Reliability Corporation guidelines.[4] This project replaces the obsolete security camera system with an updated, state of the art surveillance system, a new controlled entrance gate system, and the replacement of the existing temporary guard house structure with a new permanent facility which includes a potable water supply and restroom serviced by an extended water line.

[4] NERC CIP-002-5.1a and CIP-003-8

99. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THIS PROJECT?

A. The current estimated cost of completion of $1,227,965, including AFUDC, was included in the Certification Period estimates based on the plan to complete this work in the spring of 2023. However, due to parts availability, this project will not be completed prior to May 31, 2023, and will be removed from the plant in service estimates when the certification filing is completed later in this Docket.

5. HA2175 and HA2176 – Harry Allen ACC Fan Blade Replacement

100. Q. PLEASE DESCRIBE THE HARRY ALLEN ACC FAN BLADE REPLACEMENT PROJECTS AND WHY THEY WERE NECESSARY.

A. Harry Allen uses an Air-Cooled Condenser ("ACC") unit to cool and convert steam to liquid. This ACC unit has a total of 36 fan assemblies used to move air for cooling. Each of these fan assemblies (cells) has nine blades per fan. There are 324 total fan blades for the entire unit, with 162 blades being the focus of this project. At least six fan blade assemblies were identified as having blades worn beyond safe use with cracking and small fractures within the fiberglass material of the blade. These types of blade anomalies indicate material degradation and eventual total blade failure. Blade failure would include separation of sections of the blade, with those sections falling nearly 100 feet to ground level.

Numerous safety and operational vulnerabilities are exposed with a blade failure event. These include the danger to plant personnel who are required

to carry out daily work tasks at ground level below the fans and the potential for dislodged blades, or blade parts, to strike areas of the ACC structural support systems. Loss of ACC fans because of equipment failures and additional threats to the unit's structure creates a risk of tripping the units due to high backpressure in the turbine exhaust duct. The projects removed and replaced the fan blades of the Harry Allen ACC.

101. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THESE PROJECTS?

A. The current estimated cost of completion is $1,143,072 (HA2175) and $1,050,390 (HA2176), including AFUDC, and the projects will be in service before May 31, 2023.

K. CERTIFICATION – LAS VEGAS GENERATING STATION

1. LV2233 and LV2234 – Power Block 2 and 3 Cooling Tower Overhaul

102. Q. PLEASE DESCRIBE THE LAS VEGAS GENERATING STATION POWER BLOCK 2 AND 3 COOLING TOWER OVERHAUL PROJECT AND WHY IT WAS NECESSARY.

A. The LVGS Blocks 2 and 3 cooling towers were 20 years old, and while they had been operating efficiently for that duration, the overall structural integrity has deteriorated. The structures' original design included wood chemically-treated specifically for cooling tower applications and corrugated sheets of fiber glass plastic. Treated wood extends the usable life span of the wood structure dramatically, but the water and chemicals used to treat cooling towers still deteriorate the wood and corrugated fiber glass over time. Following inspections by the cooling tower manufacture

and others, replacement of all structural support members was strongly recommended.

The scope of this project was to replace the treated wood with an upgraded fiberglass material and stainless-steel fasteners, as well as replace all damaged corrugated fiber glass sheeting, so that the structures meet or exceed the current standard construction material for new cooling towers. The work scope was developed from the inspection reports' findings.

103. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THIS PROJECT?

A. The plant in service is $1,379,533 (LC2233) and $1,387,404 (LC2234), including AFUDC, and the projects were completed on February 24, 2023 (LC2233) and April 20, 2023 (LC2234) and are currently in service.

L. CERTIFICATION – SUN PEAK GENERATING STATION

1. SK2042 – Units 3-5 Ovation Control System Upgrade

104. Q. PLEASE DESCRIBE THE SUN PEAK UNITS 3-5 OVATION CONTROL SYSTEM UPGRADE PROJECT AND WHY IT WAS NECESSARY.

A. The Ovation DCS at Sun Peak has reached its lifespan and the HMIs and servers need to be updated to bring them within required parameters for cyber-security. The existing HMIs are running Windows 7 operating system, which has moved beyond end of useful life. At this point, security patches are no longer available for these systems and the patch-ability

requirement can no longer be met, which compromises the reliability of the system and significantly increases risk to the plant's cyber-security.

The scope of the project is to update the HMIs, servers, and network infrastructure to ensure that the systems maintain reliability and stay current as prescribed by cyber security policy. Similar projects were presented to and approved by the Commission in Sierra's 2022 General Rate Case.

105. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THIS PROJECT?

A. The plant in service is $4,270.591, including AFUDC, and the project was completed and in service on February 24, 2023.

<u>SECTION 6. GENERATION INVESTMENT BETWEEN JUNE 1, 2023, AND DECEMBER 31, 2023, FOR EXPECTED CHANGE IN CIRCUMSTANCES ("ECIC").</u>

106. Q. ARE THERE ANY PROJECTS THAT ARE PROJECTED INVESTMENT IN GENERATION ASSETS BETWEEN JUNE 1, 2023, AND DECEMBER 31, 2023, THAT SHOULD BE CONSIDERED IN EXPECTED CHANGE IN CIRCUMSTANCES?

A. Nevada Power is completing two major investments in its generation fleet between June 1, 2023, and December 31, 2023. I discuss below the investment through:

A. Clark
1. CS2270 - CS Peaker Ovation Migration

B. Higgins

1. WH2159 – Distributed Control System (Ovation) Replacement

M. EXPECTED CHANGE IN CIRCUMSTANCES – CLARK STATION

1. CS2270 – Clark Peaker Ovation Migration

107. Q. PLEASE DESCRIBE THE CLARK PEAKER OVATION MIGRATION PROJECT AND WHY IT IS NECESSARY.

A. This project will migrate the Emerson Ovation Control System now in place, from its current version to the most recent version. The existing version of the Ovation Control System at Clark is Ovation 1.9. The current production version of Ovation is 3.7. The existing Operating System ("O/S") on these HMIs is Solaris 10. The current O/S version is Windows 10. Patches have not been available for these systems for more than 10 years. The dictates of the VMP require that the O/S must be new enough that there are patches available and that they be applied regularly. These systems cannot be patched since patches are no longer made for these operating systems. New hardware replacements have not been available for about the same amount of time. This poses significant threats to both the cyber security, physical safety and the reliability of these systems. There simply are no security updates available, nor are there spare parts available when something major fails. Similar projects were presented to and approved by the Commission in Sierra's 2022 General Rate Case.

108. Q. NRS 704.110(4) STATES THAT AN ITEM INCLUDED IN THE EXPECTED CHANGE IN CIRCUMSTANCE PERIOD MUST BE "REASONABLY KNOWN AND MEASUREABLE WITH REASONABLE ACCURACY." ARE THE EXPECTED COSTS OF THE CLARK PEAKER OVATION MIGRATION PROJECT "REASONABLY KNOWN AND MEASURABLE WITH REASONABLE ACCURACY" AS OF THE DATE YOUR TESTIMONY IS BEING PREPARED?

A. Yes. The project is planned to be completed in the fall of 2023 during the scheduled plant outage. The contracts for supply and installation were bid and executed in December 2021, for the work to be completed during the fall 2023 outage.

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109. Q. NRS 704.110(4) STATES THAT THE COMMISSION SHALL FIND THAT AN EXPECTED CHANGE IS REASONABLY KNOWN AND MEASURABLE WITH REASONABLE ACCURACY IF, AMONG OTHER THINGS, IT CONSISTS OF SPECIFIC AND IDENTIFIABLE EVENTS OR PROGRAMS RATHER THAN GENERAL TRENDS, PATTERNS OR DEVELOPMENTS. DOES THE CLARK PEAKER OVATION MIGRATION PROJECT MEET THAT CRITERION?

A. Yes. The project scope to install the Clark Peaker Ovation Migration includes the purchase and installation of equipment based on contract purchase orders from the contract bid and executed in December 2021.

110. Q. NRS 704.110(4) STATES THAT THE COMMISSION SHALL FIND THAT AN EXPECTED CHANGE IS REASONABLY KNOWN AND MEASURABLE WITH REASONABLE ACCURACY IF, AMONG OTHER THINGS, IT HAS AN OBJECTIVELY HIGH PROBABILITY OF OCCURRING TO THE DEGREE, IN THE AMOUNT AND AT THE TIME EXPECTED. DOES THE CLARK PEAKER OVATION MIGRATION PROJECT MEET THAT CRITERION?

A. Yes. The deliverables and installation schedule provided by the vendors ensure completion during the fall of 2023 outage that will begin October 10, 2023, and be completed on November 22, 2023. One of the three blocks and the balance of plant at the Clark Peakers have already been migrated to the Ovation system and the remaining two blocks will be migrated during the fall outage.

111. Q. NRS 704.110(4) STATES THAT THE COMMISSION SHALL FIND THAT AN EXPECTED CHANGE IS REASONABLY KNOWN AND MEASURABLE WITH REASONABLE ACCURACY IF, AMONG OTHER THINGS, IT IS PRIMARILY MEASUREABLE BY RECORDED OR VERIFIABLE REVENUES AND EXPENSES AND IS EASILY AND OBJECTIVELY CALCULATED, WITH THE CALCULATION OF THE EXPECTED CHANGES RELYING ONLY SECONDARILY ON ESTIMATES, FORECASTS, PROJECTIONS OR BUDGETS. DOES THE CLARK PEAKER OVATION MIGRATION PROJECT MEET THAT CRITERION?

A. Yes. All the project costs related to the installation of the Ovation migration project are currently verifiable and recorded in the contracts and purchase orders.

112. Q. PLEASE SUMMARIZE WHY THE CLARK PEAKER OVATION MIGRATION PROJECT MEETS THE CRITERIA SPECIFIED IN NRS 704.110(4) AS AN EXPECTED CHANGE THAT IS REASONABLY KNOWN AND MEASURABLE WITH REASONABLE ACCURACY.

A. The Clark Peaker Ovation Migration project constitutes a specific and identifiable event, these events have an objectively high probability of occurring to the degree, in the amount and at the time expected, and their costs are currently measurable by recorded and verifiable expenses that are easily and objectively calculated.

113. Q. NRS 704.110(4) STATES THAT THE COMMISSION SHOULD CONSIDER "REASONABLE PROJECTED OR FORECASTED OFFSETS IN REVENUE AND EXPENSES THAT ARE DIRECTLY ATTRIBUTABLE TO OR ASSOCIATED WITH THE EXPECTED CHANGES IN CIRCUMSTANCES UNDER CONSIDERATION." ARE THERE ANY OFFSETS ASSOCIATED WITH THE CLARK PEAKER OVATION MIGRATION PROJECT?

A. The Company has not identified any reasonable projected or forecasted offsets in revenues or expenses that are directly attributable to or associated with these expected changes in circumstances.

114. Q. WHY SHOULD THIS PROJECT BE CONSIDERED FOR ECIC?

A. This project was planned for completion during the fall of 2023. This project requires a full plant outage due to the required installation of the Ovation operating systems. The contracts for supply and installation are already in place.

115. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THIS PROJECT?

A. The estimated cost of completion for project C2270 used in the worksheets of this filing is $14,584,656, including AFUDC. The current estimate at completion is $15,097,654, including AFUDC. The update of this cost estimate will be included in certification filing of this Docket. The project is scheduled to be completed on December 1, 2023.

N. EXPECTED CHANGE IN CIRCUMSTANCES – WALT HIGGINS STATION

1. WH2159 – Distributed Control System (Ovation) Migration

116. Q. PLEASE DESCRIBE THE WALT HIGGINS DISTRIBUTED CONTROL SYSTEM (OVATION) REPLACEMENT PROJECT AND WHY IT WAS NECESSARY.

A. Higgins is required to replace its Siemens T3000 (T3K) Control System with the Emerson Ovation Control System in order to install a patchable (security) package and to ensure compliance with the VMP and current NV Energy cyber security standards. The Higgins plant is the only plant in the Companies' fleet that uses the Siemens T3000 control system. The T3000 system has some inherent cyber-security flaws that make it incapable of meeting current the Companies' cyber security standards. The project will also update outlying systems, using individual Programable Logic Controllers and integrate those systems into the DCS. Similar projects were presented to and approved by the Commission in Sierra's 2022 General Rate Case.

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117. Q. NRS 704.110(4) STATES THAT AN ITEM INCLUDED IN THE EXPECTED CHANGE IN CIRCUMSTANCE PERIOD MUST BE "REASONABLY KNOWN AND MEASUREABLE WITH REASONABLE ACCURACY." ARE THE EXPECTED COSTS OF THE DISTRIBUTED CONTROL SYSTEM (OVATION) MIGRATION PROJECT "REASONABLY KNOWN AND MEASURABLE WITH REASONABLE ACCURACY" AS OF THE DATE YOUR TESTIMONY IS BEING PREPARED?

A. Yes. The project is planned to be completed in the fall of 2023 during the scheduled plant outage. The contracts for the supply and installation were bid and executed in December 2021, for the work that is being completed in the fall 2023 outage.

118. Q. NRS 704.110(4) STATES THAT THE COMMISSION SHALL FIND THAT AN EXPECTED CHANGE IS REASONABLY KNOWN AND MEASURABLE WITH REASONABLE ACCURACY IF, AMONG OTHER THINGS, IT CONSISTS OF SPECIFIC AND IDENTIFIABLE EVENTS OR PROGRAMS RATHER THAN GENERAL TRENDS, PATTERNS OR DEVELOPMENTS. DOES THE DISTRIBUTED CONTROL SYSTEM (OVATION) MIGRATION PROJECT MEET THAT CRITERION?

A. Yes. The project scope to install the DCS and migrate the system to the Ovation system includes the purchase and installation of equipment based on contract purchase orders already in place.

119. Q. NRS 704.110(4) STATES THAT THE COMMISSION SHALL FIND THAT AN EXPECTED CHANGE IS REASONABLY KNOWN AND MEASURABLE WITH REASONABLE ACCURACY IF, AMONG OTHER THINGS, IT HAS AN OBJECTIVELY HIGH PROBABILITY OF OCCURRING TO THE DEGREE, IN THE AMOUNT AND AT THE TIME EXPECTED. DOES THE DISTRIBUTED CONTROL SYSTEM (OVATION) MIGRATION PROJECT MEET THAT CRITERION?

A. Yes. The deliverables and installation schedule provided by the vendors ensure completion during the fall of 2023 outage that will begin October 1 , 2023 and be completed on December 14, 2023.

120. Q. NRS 704.110(4) STATES THAT THE COMMISSION SHALL FIND THAT AN EXPECTED CHANGE IS REASONABLY KNOWN AND MEASURABLE WITH REASONABLE ACCURACY IF, AMONG OTHER THINGS, IT IS PRIMARILY MEASUREABLE BY RECORDED OR VERIFIABLE REVENUES AND EXPENSES AND IS EASILY AND OBJECTIVELY CALCULATED, WITH THE CALCULATION OF THE EXPECTED CHANGES RELYING ONLY SECONDARILY ON ESTIMATES, FORECASTS, PROJECTIONS OR BUDGETS. DOES THE DISTRIBUTED CONTROL SYSTEM (OVATION) MIGRATION PROJECT MEET THAT CRITERION?

A. Yes. All the project costs related to the installation of the Ovation migration project are currently verifiable and recorded in the contracts and purchase orders.

121. Q. PLEASE SUMMARIZE WHY THE DISTRIBUTED CONTROL SYSTEM (OVATION) MIGRATION PROJECT MEETS THE CRITERIA SPECIFIED IN NRS 704.110(4) AS AN EXPECTED CHANGE THAT IS REASONABLY KNOWN AND MEASURABLE WITH REASONABLE ACCURACY.

A. The Distributed Control System (Ovation) Migration project constitutes a specific and identifiable event, these events have an objectively high probability of occurring to the degree, in the amount and at the time expected, and their costs are currently measurable by recorded and verifiable expenses that are easily and objectively calculated.

122. Q. NRS 704.110(4) STATES THAT THE COMMISSION SHOULD CONSIDER "REASONABLE PROJECTED OR FORECASTED OFFSETS IN REVENUE AND EXPENSES THAT ARE DIRECTLY ATTRIBUTABLE TO OR ASSOCIATED WITH THE EXPECTED CHANGES IN CIRCUMSTANCES UNDER CONSIDERATION." ARE THERE ANY OFFSETS ASSOCIATED WITH THE DISTRIBUTED CONTROL SYSTEM (OVATION) MIGRATION PROJECT?

A. The Company has not identified any reasonable projected or forecasted offsets in revenues or expenses that are directly attributable to or associated with these expected changes in circumstances.

123. Q. WHY SHOULD THIS PROJECT BE CONSIDERED FOR ECIC?

A. This project was planned for completion during the fall of 2023. This project requires a full plant outage due to the required installation of the Ovation operating systems. The contracts for supply and installation are already in place.

124. Q. WHAT IS THE CURRENT ESTIMATED COST OF COMPLETION FOR THIS PROJECT?

A. The estimated cost of completion for the project of $14,421,514 included in the direct filing and the current estimated cost of completion is $14,634,539, including AFUDC. The update of this cost estimate will be included in certification filing of this Docket. The project is scheduled to be completed on December 14, 2023.

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

A. Yes, it does.

EXHIBIT LESCENSKI-DIRECT-1

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

Currently pursuing a Masters of Arts in Economics – University of Nevada, Las Vegas ▪ Spring 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

EXHIBIT LESCENSKI-DIRECT-2

Exhibit Lescenski-Direct-2

Projects Completed Between 06/01/2020 and 12/31/2023

		Certification Period Estimate
A. Chuck Lenzie Generating Station		
1. CL2089 LZ Gas Supply Piping System, Install	$	2,019,751
2. CL2116 NP 20 MW 7F (Lenzie CT3), Upgrade	$	23,256,170
CL2117 NP 20 MW 7F (Lenzie CT4), Upgrade	$	23,406,689
CL2118 NP 20 MW 7F (Lenzie CT1), Upgrade	$	23,698,471
CL2119 NP 20 MW 7F (Lenzie CT2), Upgrade	$	23,685,926
3. CL2127 LZ PB2 Bal. of Plant Controls	$	21,173,198
4. CL2179 LZ PB1 Chemical Injection Building, Replace	$	1,876,852
CL2182 LZ PB2 Chemical Injection Building, Replace	$	1,992,061
5. CL2220 LZ CT4 Compressor Rotor, Replace	$	6,381,185
B. Clark Station		
1. CS2027 Clark-11A Power Turbine Upgrade and Overhaul	$	1,094,388
CS2034 Clark - 19 A Power Turbine Upgrade and Overhaul	$	1,102,660
2. CS2153 CK PKRS - Repl Stack Outlet Exp Joints (12)	$	1,133,409
3. CS2201 Clark Unit 5 - CT - Hot Gas Path Inspection	$	983,099
CS2202 Clark Unit 6 – CT – Hot Gas Path Overhaul	$	1,429,072
4. CS2223 CK PKRS Fuel Gas Control Valves and Drivers	$	1,465,956
5. CS2238 CK - PKRS – Purchase Capital Spare Generator	$	2,116,649
6. CS2251 CK - PKRS – PB 1-3 – Bus Duct – Rebuild	$	2,422,891
7. CS2286 CK - Unit 18 B Gas Generator Rebuild	$	2,118,119
CS2317 CK - Unit 20 B - Gas Generator	$	2,901,481
CS2344 CK - Unit 15 B - Gas Generator	$	2,410,921
CS2348 CK - Unit 22 B - Gas Generator	$	1,831,796
CS2351 CK - Unit 20 A - Gas Generator	$	2,728,633
CS2352 CK - Unit 18 A - Gas Generator	$	2,778,814
CS2368 CK - Unit 19 A - Gas Generator	$	987,575
CS2361 CK - Unit 21 A - Gas Generator	$	946,921
8. CS2346 CK - Capital Spare GG8 Gas Generator	$	6,292,418
C. Harry Allen Generating Station		
1. HA2153 HA4 Combustion System	$	2,858,703
2. HA2190 HA3 CT Wet Compression System, Install	$	2,292,461
HA2191 HA4 CT Wet Compression System, Install	$	2,240,591
3. HA2206 HA4 Generator Rewind	$	1,199,520
D. Las Vegas Generating Station		
1. LC2177 LC Ovation, Install	$	9,320,990

Exhibit Lescenski-Direct-2

Projects Completed Between 06/01/2020 and 12/31/2023

		Certification Period Estimate
E. Silverhawk Generating Station		
1. SH2036 SH CTB Rotor, Replace	$	4,797,483
2. SH2073 SH Turbine Controls System, Replace	$	7,089,050
3. SH2089 SH HRSG A Liner, Replace	$	1,495,794
SH2093 SH HRSG B Liner, Replace	$	1,366,290
4. SH2105 SH ST Major Capital	$	4,628,506
5. SH2117 NP 17 MW 501F (Silverhawk CTA), Upgrade	$	19,115,228
SH2118 NP 17 MW 501F (Silverhawk CTB), Upgrade	$	16,769,143
6. SH2232 SH CT Wet Compression System, Install	$	7,435,469
E. Sun Peak Generating Station		
1. SK2023 Sun Peak Unit 4 GT – Hot Gas Path Overhaul	$	2,738,503
G. Higgins Generating Station		
1. WH2163 WH2 Generator Exciter, Replace	$	1,262,570
2. WH2170 WH1 Compressor Diaphragms, Replace	$	1,579,723
3. WH2171 WH CT Wet Compression System, Install	$	9,274,060

Exhibit Lescenski-Direct-2

LTSA Projects

Projects Completed Between 06/01/2020 and 05/31/2023

		LTSA Costs
A. Chuck Lenzie Generating Station		
CL1103 - 2021 CT1 & CT2 Outage	$	18,288,061
CL1104 - 2020 CT3 & CT4 Outage	$	17,956,536
C. Harry Allen Generating Station		
HA1089 - 2023 Outage (CERT Period)	$	16,727,587
D. Silverhawk Generating Station		
SH1104 - 2022 CTB Major Outage	$	10,018,353
SH2189 - 2022 CTA Hot Gas Path	$	6,621,577
E. Walt Higgins Generating Station		
WH1059 - 2020 CT Major Outages	$	16,695,459

Exhibit Lescenski-Direct-2
Certification Period Projects
Projects Completed Between 01/01/2023 and 05/31/2023

		Certification Period Estimate
A. Chuck Lenzie Generating Station		
1. CL2127 LZ PB2 Balance of Plant Controls	$	10,333,979
CL2128 LZ PB1 Balance of Plant Controls	$	8,110,177
B. Clark Station		
1. CS2203 Clark Unit 7 – CT – Hot Gas Path Overhaul	$	1,623,674
2. CS2221 Clark 4-10 DCS Upgrade	$	9,748,993
3. CS2263 CK PKRS – Power Turbine EGT Upgrades	$	2,409,520
4. CS2336 CK Peaker Wet Compression System	$	20,219,551
5. CS2387 CK – Unit 12 A – Gas Generator	$	2,933,617
CS2388 CK – Unit 12 B – Gas Generator	$	2,936,064
CS2393 CK – Unit 20 B – Gas Generator	$	2,970,622
C. Harry Allen Generating Station		
1. HA1050 HA CC Steam Turbine Major Overhaul	$	1,185,767
2. HA2090 HA CT 5 22 MW 7F Upgrade	$	23,840,082
HA2091 HA CT 6 22 MW 7F Upgrade	$	31,015,777
3. HA2155 HA3 Combustion System Capital Parts Repla	$	2,685,328
4. HA2160 HA Guard House, Entrance Gate and Security Cameras	$	1,227,965
5. HA2175 ACC Fan Blade Replacement (2022)	$	1,143,072
HA2176 ACC Fan Blade Replacement (2023)	$	1,050,390
D. Las Vegas Generating Station		
1. LC2233 PB 2 Cooling Tower Overhaul	$	1,379,533
LC2234 PB 3 Cooling Tower Overhaul	$	1,387,404
E. Sun Peak Generating Station		
1. SK2042 SK Units 3-5 Ovation Control System Updat	$	4,270,591

Exhibit Lescenski-Direct-2

ECIC Projects

Projects to be Completed Between 06/01/2023 and 12/31/2023

		Project Costs
A. Clark Generating Station		
CS2270 - Clark Peaker Ovation Migration	$	14,584,656
B. Walt Higgins Generating Station		
WH2159 -	$	14,421,514

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: June 5, 2023

John Lescenski

SHANE PRITCHARD

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 23-06___
2023 General Rate Case

Prepared Direct Testimony of

Shane Pritchard

Revenue Requirement

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

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

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

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.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR OF RENEWABLE ENERGY AND ORIGINATION.

A. 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**.

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

A. Yes. Most recently, I provided written testimony in Docket No. 22-11032, the Fourth Amendment to the 2021 Joint Integrated Resource Plan ("IRP").

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

A. I demonstrate the prudence of investment in the construction of the Mojave High School Solar project that is included in the calculation of Nevada Power's revenue requirement. In addition, I am providing updated information related to the Reid Gardner grid-tied battery energy storage system ("BESS"), an Expected Change in Circumstance ("ECIC") in accordance with NRS 704.110(4). Finally, I provide updated cost and project details related to the U.S. Department of Energy ("DOE") BESS located at the Beltway Substation.

6. 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 Reid Gardner BESS project Cost Summary (Confidential)

Exhibit Pritchard-Direct-3 Mojave High School Solar Project Cost Summary

Exhibit Pritchard-Direct-4 Performance Report of Mojave High School Solar project

Exhibit Pritchard-Direct-5 DOE BESS project Cost Summary (Confidential)

7. Q. IS THE COMPANY REQUESTING CONFIDENTIAL TREATMENT OF CERTAIN INFORMATION CONTAINED IN YOUR TESTIMONY?

A. Yes. **Exhibit Pritchard-Direct-2** contains the price paid to BYD for the Reid Gardner BESS, which if publicly disclosed could place the Company at a competitive disadvantage to receive competitively priced proposals from suppliers in the future. **Exhibit Pritchard-Direct-2** contains proprietary BYD information that could place the manufacturer at a disadvantage if made public and disclosure is prohibited under a confidentiality agreement between BYD and Nevada Power. Additionally, **Exhibit Pritchard-Direct-5** contains the price paid to ELM Utility Services, Inc. ("ELM") for the DOE BESS, which if publicly disclosed, could place the Company at a competitive disadvantage to receive competitively priced proposals from suppliers in the future.

8. Q. FOR HOW LONG DOES THE COMPANY REQUEST CONFIDENTIAL TREATMENT?

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

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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 Company's ECIC related to the Reid Gardner BESS and its costs. In section III, I discuss the background and reasons for building the Mojave High School Solar project, its costs, and performance. In section IV, I discuss the background and reasons for building the DOE BESS project and its costs.

II. CONSTRUCTION OF THE REID GARDNER BESS

11. Q. PLEASE DESCRIBE THE REID GARDNER BESS.

A. The Reid Gardner BESS is a 220-MW Lithium-Ion battery with two hours of energy storage (440 MWh) that is currently being constructed to help close the capacity open position of the Companies, specifically the critical summer peak capacity. It will also help shift solar energy production to times the energy is needed more. It is comprised of 208 containerized battery enclosures as well as inverters and other power electronics. The battery enclosures are manufactured by BYD, and the main Engineer, Procure, Construct ("EPC") contractor for the site is Energy Vault, Inc. The project is located on reclaimed land at the former Reid Gardner facility and interconnects at 230 kV voltage to the Reid Gardner Substation. The

Reid Gardner BESS is expected to begin commercial operation on December 29, 2023. The total costs of the project, which are reasonably known and measurable with reasonable accuracy as of the date of this rate case filing, are expected to be $255.6 million, including allowance for funds used during construction ("AFUDC"). This cost is before application of the Investment Tax Credit ("ITC"), expected to be 40 percent, recently made available by the Investment Reduction Act ("IRA").

12. Q. WAS THE PROJECT PRE-APPROVED BY THE COMMISSION IN AN IRP?

A. Yes, the Reid Gardner BESS was approved by the Commission in Docket No. 22-03024 with a cap on the project price not to exceed $257 million, excluding AFUDC.

13. Q. HAVE THE PROJECT'S CHARACTERISTICS OR COST CHANGED SINCE IT WAS APPROVED?

A. Yes, there have been changes in project schedule and cost since it was approved by the Commission. In this general rate application, the Companies are submitting the ECIC in accordance with NRS 704.110(4).

14. Q. DESCRIBE THE VARIOUS CHANGES TO THE ECIC PROJECT COST AND SCHEDULE

A. The project commercial operation date ("COD") is now projected to be December 29, 2023. The cost schedule as presented in **Exhibit Pritchard-Direct-2** for the Reid Gardner BESS has been updated to show a forecasted cost of $255.6 million including AFUDC.

15. Q. NRS 704.110(4) STATES THAT AN ITEM INCLUDED IN THE ECIC PERIOD MUST BE "REASONABLY KNOWN AND MEASUREABLE WITH REASONABLE ACCURACY." ARE THE EXPECTED COSTS OF THE REID GARDNER BESS "REASONABLY KNOWN AND MEASURABLE WITH REASONABLE ACCURACY" AS OF THE DATE YOUR TESTIMONY IS BEING PREPARED?

A. Yes. Contracts for the Reid Gardner BESS have been executed and purchase orders issued for project equipment including batteries, EPC and balance of plant, transformer, breakers, and other related project costs. Further detail is provided in the cost schedule as presented in **Exhibit Pritchard-Direct-2.**

16. Q. NRS 704.110(4) STATES THAT THE COMMISSION SHALL FIND THAT AN EXPECTED CHANGE IS REASONABLY KNOWN AND MEASURABLE WITH REASONABLE ACCURACY IF, AMONG OTHER THINGS, IT CONSISTS OF <u>SPECIFIC AND IDENTIFIABLE EVENTS</u> OR PROGRAMS RATHER THAN GENERAL TRENDS, PATTERNS OR DEVELOPMENTS. DOES THE REID GARDNER BESS MEET THAT CRITERION?

A. Yes. The project scope to acquire and install Reid Gardner BESS includes the engineering, purchase, delivery, and installation of the BESS on contract purchase orders and detailed delivery schedules, and cannot be characterized as a general trend, pattern, or development. The COD is projected to be December 29, 2023, which is within 210 days after the date of this filing per NRS 704.110(4). As a result, this project is not considered to be classified as general trends, patterns, or developments.

17. Q. NRS 704.110(4) STATES THAT THE COMMISSION SHALL FIND THAT AN EXPECTED CHANGE IS REASONABLY KNOWN AND MEASURABLE WITH REASONABLE ACCURACY IF, AMONG OTHER THINGS, IT HAS AN OBJECTIVELY <u>HIGH PROBABILITY OF OCCURRING TO THE DEGREE, IN THE AMOUNT AND AT THE TIME EXPECTED.</u> DOES THE REID GARDNER BESS MEET THAT CRITERION?

A. Yes. Revised delivery and construction schedules provided by the EPC and contained in the contracts for the project demonstrate completion of delivery, installation, testing and operation by December 29, 2023, which satisfies the current construction schedule to install and commission the Reid Gardner BESS.

18. Q. NRS 704.110(4) STATES THAT THE COMMISSION SHALL FIND THAT AN EXPECTED CHANGE IS REASONABLY KNOWN AND MEASURABLE WITH REASONABLE ACCURACY IF, AMONG OTHER THINGS, IT IS PRIMARILY MEASUREABLE BY <u>RECORDED OR VERIFIABLE REVENUES AND EXPENSES</u> AND IS EASILY AND <u>OBJECTIVELY CALCULATED,</u> WITH THE CALCULATION OF THE EXPECTED CHANGES RELYING ONLY SECONDARILY ON ESTIMATES, FORECASTS, PROJECTIONS OR BUDGETS. DOES THE REID GARDNER BESS MEET THAT CRITERION?

A. Yes. All the project material costs related to the purchase, delivery, and installation of the BESS are currently verifiable and recorded in the contracts and purchase orders, as shown in **Exhibit Pritchard-Direct-2**. The required site remediation, physical security, warehouse upgrade, and network, cybersecurity, and telecom

upgrades costs are currently estimates considered to be accurate and comprised of approximately 1.6 percent of the total project cost.

19. Q. PLEASE SUMMARIZE WHY THE REID GARDNER BESS MEETS THE CRITERIA SPECIFIED IN NRS 704.110(4) AS AN EXPECTED CHANGE THAT IS REASONABLY KNOWN AND MEASURABLE WITH REASONABLE ACCURACY?

A. The Reid Gardner BESS project constitutes a specific and identifiable event, these events have an objectively high probability of occurring, in the amount and at the time expected, and their costs are currently measurable by recorded and verifiable expenses and estimates that are easily and objectively calculated.

20. Q. NRS 704.110(4) STATES THAT THE COMMISSION SHOULD CONSIDER "REASONABLE PROJECTED OR FORECASTED OFFSETS IN REVENUE AND EXPENSES THAT ARE DIRECTLY ATTRIBUTABLE TO OR ASSOCIATED WITH THE EXPECTED CHANGES IN CIRCUMSTANCES UNDER CONSIDERATION." ARE THERE ANY OFFSETS ASSOCIATED WITH THE ACQUISITION AND CONSTRUCTION OF THE REID GARDNER BESS?

A. The Company has not identified any reasonable projected or forecasted offsets in revenues or expenses that are directly attributable to or associated with these expected changes in circumstances.

21. Q. DESCRIBE THE CURRENT STATUS OF THE REID GARDNER BESS.

A. Permitting is in the final stages of approvals with the final Utility Environmental Protection Act ("UEPA") approval anticipated in August this year. Construction

will begin immediately after UEPA approval is obtained. The EPC contractors have ordered all major components to support the project schedule. Major equipment will begin arriving onsite in July with the BESS deliveries beginning in September. The transmission interconnection schedule supports the anticipated COD date of December 29, 2023. There are no currently known obstacles that would prevent completion of the project before December 29, 2023.

III. MOJAVE HIGH SCHOOL SOLAR PROJECT

22. Q. PLEASE DESCRIBE MOJAVE HIGH SCHOOL SOLAR.

A. Mojave High School Solar is a 350-kW solar photovoltaic project located at Mojave High School, a Title 1 school located on Clark County School District ("CCSD") property in North Las Vegas, Nevada, and has been in service since December 21, 2021, its commercial operation date ("COD"). The project includes newly constructed carports that house a fixed-tilt solar system of approximately 1,000 photovoltaic modules that generate at least 773,000 kilowatt-hours per year. It is owned and operated by Nevada Power and is the first Community Based Solar Resource as part of the Companies' Expanded Solar Access Program ("ESAP") mandated by Assembly Bill 465 ("AB465"). The project was approved by the Commission in Docket No. 20-07023.

23. Q. PLEASE DESCRIBE THE PERFORMANCE OF MOJAVE HIGH SCHOOL SOLAR.

A. The Mojave High School Solar facility has been performing as expected. All facility O&M continue to be performed per the EPC contract's workmanship warranty, which includes but is not limited to, daily monitoring of system performance, active response to any system faults, and quarterly O&M. The facility

generated over 816,624 kilowatt-hours in 2022. The availability and other operational data are shown in **Exhibit Pritchard-Direct-4** Performance Report of Mojave High School Solar project.

24. Q. PLEASE DESCRIBE THE MOJAVE HIGH SCHOOL SOLAR PROJECT COSTS.

A. The total estimated project cost, as of the time of this filing, is $1,615,937.49 including AFUDC. Additional detail can be found in **Exhibit Pritchard-Direct-3** Mojave High School Solar Project Cost Summary.

25. Q. PLEASE DESCRIBE THE MOJAVE HIGH SCHOOL SOLAR ONGOING COSTS.

A. The facility's O&M work continues to be performed per the EPC contract's workmanship warranty. The EPC contractor, Bombard Electric, Inc., covers daily system performance monitoring, corrective warranty work, and quarterly preventive maintenance services. Additionally, Nevada Power has budgeted $30,000 per year for operations and maintenance costs due to non-preventative maintenance and/or work not covered by warranty.

IV. DOE BESS PROJECT

26. Q. ARE ANY PROJECTS ANTICIPATED TO BE ADDED TO THE CERTIFICATION PERIOD THAT HAVE NOT BEEN INCLUDED IN THE COMPANY'S DIRECT FILING PLANT ADDITIONS SCHEDULE H-CERT-13?

A. Yes. The certification period estimates provided to Accounting in early March 2023 did not include the DOE BESS and it is not reflected in the plant additions

schedule H-CERT-13. This project, along with a list of other projects that could be placed into service early, has been included in Company witness Christina Hanshew's Exhibit Hanshew Direct-3. This project was previously anticipated to be placed into service in July 2023, however, it was placed into service on April 29, 2023. Because the project entered service during the certification period, the project will be included in the Certification filing to be made by the Company. Project cost details related to the DOE BESS are provided in **Exhibit Pritchard-Direct-5.**

27. Q. PLEASE DESCRIBE THE DOE BESS.

A. The DOE BESS is a 1-MW Lithium-Ion battery facility with 4 megawatt-hours of energy storage. It supports a DOE-sponsored project to demonstrate the provision of grid services from aggregated distributed energy resources ("DER"). The BESS is comprised of four containerized battery enclosures as well as inverters and other power electronics. The main EPC contractor for the project was ELM. The project is located in the northeast corner of the NV Energy Beltway Substation and interconnects at 12 kV to the Beltway substation. The project was approved by the Commission in Docket No. 21-06001 and updated in Docket No. 22-09001. The DOE BESS began commercial operation April 29, 2023.

28. Q. DESCRIBE THE TOTAL COST OF THE DOE BESS PROJECT.

A. The total cost to build the project is expected to be $2,626,686.94 including AFUDC and is shown in more detail in **Exhibit Pritchard-Direct-5** DOE BESS project Cost Summary. Additional costs associated with the interconnection of the project are described separately within this rate case application in Company witness Vincent Veilleux's direct testimony.

29. Q. ARE THERE ONGOING COSTS FOR THE DOE BESS?

A. Yes, the Company estimates ongoing O&M expenses to be approximately $7,850 per year. This includes a Maintenance Agreement with ELM who provides ongoing software support and preventative maintenance services. In addition to various equipment manufacturers' warranties, ELM provides a 24-month warranty for the BESS system.

30. Q. PLEASE SUMMARIZE NEVADA POWER'S REQUESTS FOR APPROVAL.

A. The Company requests that the Commission approve: ECIC costs including the construction and ongoing capital costs of the Reid Gardner BESS, including AFUDC, in rates; the inclusion of the Mojave High School Solar project, ongoing capital, and O&M costs in rates; and the inclusion of the DOE BESS project capital costs as well as O&M costs in rates.

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

A. Yes.

EXHIBIT PRITCHARD-DIRECT-1

SHANE E. PRITCHARD
6226 West Sahara Ave.
Las Vegas, NV 89151-001
702-439-3545
shane.pritchard@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 developed testimony and responded 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

FILED UNDER CONFIDENTIAL SEAL

EXHIBIT PRITCHARD-DIRECT-3

Exhibit 3 - Mojave High School Solar Costs

Sum of Actual Amount		Year ID			
Budget ID ID	Resource Type ID	2021	2022	2023	Grand Total
D6414	10	1,993.53	233.02		2,226.55
	11	1,029.65	48.51		1,078.16
	12	68.00			68.00
	30	1,554.66	188.46		1,743.12
	31	153.58			153.58
	32	729.14	11.82		740.96
	33	2,548.39	101.41		2,649.80
	40	8,091.40	309.07		8,400.47
	50	11,949.11			11,949.11
	52	972.22			972.22
	60	124.48	1.50		125.98
	70		359.98		359.98
	80	156.25			156.25
D6414 Total		**29,370.41**	**1,253.77**		**30,624.18**
RP2053	10	18,234.36	998.40		19,232.76
	30	13,130.11	778.75		13,908.86
	31	1,632.48			1,632.48
	32	44,328.23	788.75	150.00	45,266.98
	40	1,402,149.25	51,638.82	15,000.00	1,468,788.07
	60	95.95			95.95
	70	8,600.00			8,600.00
	75	330.96	110.52		441.48
	80	19,996.17	-3,821.48		16,174.69
	81	41,796.22			41,796.22
RP2053 Total		**1,550,293.73**	**50,493.76**	**15,150.00**	**1,615,937.49**

Summary

Total through 02/28/23	
Engineering, Procurement and Construction	$1,458,894.45
Distribution Interconnection (D6414)	$ -
Permitting (including appraisal, lease payment, etc.)	$ 8,100.00
Project Management	$ 148,943.04
Total	$1,615,937.49

EXHIBIT PRITCHARD-DIRECT-4

Exhibit 4 - Mojave High School Solar Performance Summary

The Mojave High School Solar CBSR ("Mojave Solar"), approved in Docket No. 20-07023 as a pilot project, commenced operations on December 21, 2021. This community based solar resource, which interconnects directly to the Company's distribution system, is a carport facility that contains approximately 1,000 solar panels and has 350-kilowatt capacity.

NV Energy worked with Bombard Electric, Inc., who was the Engineering, Procurement and Construction ("EPC") contractor, and achieved final completion of the Mojave Solar project on March 9, 2022. This project has been performing as expected. All facility operations and maintenance ("O&M") continue to be performed per the EPC contract's workmanship warranty, which includes but is not limited to, daily monitoring of system performance, active response to any system faults, and quarterly O&M. The following table includes the monthly energy production since the Mojave Solar project commenced operations:

Month	Energy Production (kilowatt-hours)	Inverter Availability (percent)
2021		
December	9,465.81	99.93%
2022		
January	47,280.49	100.00%
February	57,066.08	100.00%
March	72,641.26	100.00%
April	83,916.41	100.00%
May	94,511.25	99.98%
June	89,594.54	99.99%
July	76,775.88	92.85%
August	74,367.44	99.99%
September	70,922.25	100.00%
October	63,627.63	99.94%
November	46,988.56	100.00%
December	38,932.81	99.73%
2022 Sub-total	816,624.58	99.37%
2023		
January	40,351.00	100.00%
February	50,647.94	99.99%
March	63,394.19	100.00%
April (until April 14, 2023)	34,930.25	99.63%
Total (since December 2021)	1,015,413.77	99.53%
Source: Mojave High School Solar AlsoEnergy PowerTrack Report, dated April 14, 2023.		

EXHIBIT PRITCHARD-DIRECT-5

FILED UNDER CONFIDENTIAL SEAL

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: June 5, 2023

Shane Pritchard

EVELENE RICCI

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 23-06___
2023 General Rate Case

Prepared Direct Testimony

Evelene Ricci

Revenue Requirement

1. Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Evelene Ricci. My current position is Director of Transmission and Distribution ("T&D") Support Services for Nevada Power Company d/b/a NV Energy ("Nevada Power" or the "Company") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies"). My business address is 295 Edison Way in Reno, Nevada. I am filing testimony on behalf of Nevada Power.

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

A. I joined the Companies in May 2005. I have more than 30 years of experience in the electric utility industry. My prior experience at the Companies has been leadership roles in large customer account management, NVEnergize meter deployment, human resources and accounting. My background and experience are further described in **Exhibit Ricci-Direct-1**.

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3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR OF T&D SUPPORT SERVICES.

A. As Director of T&D Support Services, I am currently responsible for the management of Fleet Services, which includes the purchase, maintenance, administration, and repair of the Companies' vehicles and fleet equipment.

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

A. Yes, I have testified in several proceedings before the Commission, most recently in Docket Nos. 22-06014 and 22-03028.

5. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibits:

- **Exhibit Ricci-Direct-1** – Statement of Qualifications

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

A. My testimony addresses vehicle and fleet equipment replacement investment costs completed since Nevada Power's 2020 general rate case ("GRC"), Docket No 20-06003. Specifically, I discuss investment in vehicles and fleet equipment since the close of the certification period in the 2020 GRC through the end of this GRC test period (June 1, 2020 – December 31, 2022), as well as vehicle and fleet equipment replacement completed in January and February of 2023, and estimated through May 31, 2023, the close of the certification period. Additionally, I provide specific information regarding the largest categories of investments for the Fleet Services department, the acquisition of new vehicles and fleet equipment to replace units that have exceeded their life cycles and the buyout of vehicle and fleet equipment

lease financial arrangements. Combined, these expenditures represent approximately $23.2 million in plant investment for Nevada Power through May 31, 2023.

Table Ricci-Direct-1 below provides costs for the test period as of December 31, 2022, and costs for the certification period of January 1, 2023, through May 31, 2023.

TABLE RICCI DIRECT - 1			
Division	Additions Jun-20 to Dec-22	Additions Jan-23 to May-23	Total Fleet Additions
Fleet Investments	$22,146,550	$1,009,913	$23,156,463

The total fleet additions were primarialy due to the purchase of 68 vehicles and fleet equipment for $22.2 million, the buyout of 76 leased vehicles and fleet equipment with an approximate residual value of $0.8 million, and the installation of safety systems (cameras and sensor technology) for $0.2 million.

7. Q. WHY HAS NEVADA POWER REPLACED VEHICLE AND FLEET EQUIPMENT SINCE JUNE 1, 2020?

A. Nevada Power's Fleet Services performs vehicle lifecycle analysis to gauge the optimal replacement plan for each vehicle and fleet equipment class to achieve the ideal total cost to own and maintain vehicles and fleet equipment over their useful lives. Fleet Services works to limit expenditures by retaining these assets through their full useful lifecycle. The average age of Nevada Power's current vehicles and fleet equipment is 11.5 years, which compares favorably to the utility industry average of 8.3 years.

8. Q. PLEASE DESCRIBE THE FINANCIAL ANALYSIS PERFORMED TO DETERMINE WHETHER TO PURCHASE OR LEASE REPLACEMENT VEHICLES AND FLEET EQUIPMENT.

A. Nevada Power's Finance department uses a present worth of revenue requirement ("PWRR") model to assess the economic impact of different alternatives for vehicle and fleet equipment analysis. The PWRR model allows the Company to compare the economic impact to the customer from buying versus leasing the vehicles and fleet equipment, and relies on inputs such as vehicle and fleet equipment values, depreciation rates, capital costs, tax rates, and lease contract terms. The PWRR is an active process which is reviewed periodically to adjust for changes that might impact the analysis, such as changes in offered terms from vendors, fluctuations in prevailing interest rates, and the variety of the types of vehicles and fleet equipment being considered for acquisition. This process is further discussed in the testimony of Michael Behrens.

9. Q. PLEASE DESCRIBE THE FINANCIAL ANALYSIS PERFORMED TO EVALUATE OPPORTUNITIES FOR BUYING OUT LEASED VEHICLES AT THE END OF THE LEASE TERM AND PRIOR TO END OF LEASE TERM .

A. The Company expects longer useful lives for all vehicles versusthe lease terms. A leased vehicle is initially modeled as a lease with buyout at the end of the lease, typically a 5 – 7 year lease with an average age at retirement of 13.1 years. Therefore, as long as the vehicles meet safety and other condition-based standards and continue to be needed as determined by the overall fleet lifecycle analysis, vehicle buyouts at the end of the lease term will result in a lower PWRR than more frequent vehicle replacements via a lease or purchse. Nevada Power purchased 74

vehicles and fleet equipment at the end of the lease terms in order to continue to utilize the vehicles for the benefit of our customers.

The Finance Department also performed a PWRR modeling analysis to determine whether a lease buyout was economical prior to the end of lease terms. The analysis determined that it was not advantageous for Nevada Power to purchase most of the existing leased vehicles before the end of the lease terms. However there were two leases from the RBS/Citizens Bank that were set to expire within 12 months where the analysis showed that there was virtually no cost difference between an early lease buyout and a buyout at the end of the leases. For this reason, Nevada Power bought out the remaining two RBS/Citizens Bank leases prior to the end of the lease term. The PWRR modeling analysis is addressed by witness Mr. Behrens.

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

A. Yes.

EXHIBIT RICCI-DIRECT-1

Evelene Ricci
Sierra Pacific Power Company, d.b.a. NV Energy
Director, T&D Support Services

I have been employed by NV Energy for 17 years and have more than 30 years of leadership experience in the utility industry. While employed by NV Energy and other small electric distribution utilities, I have held numerous positions where I have gained expertise in asset management.

Employment History

Sierra Pacific Power Company, d/b/a. NV Energy

Director T&D Support Services (2021 – present)

Directs the development, planning, and maintenance of the company's regional fleet vehicle and equipment operations.

Director Major Accounts, (2014 – 2021)

Directs the account executive programs to promote enhanced business relations and program utilization with prominent customers.

Northern Deployment Project Director (2011 – 2014)

Directs the meter deployment and operations for the implementation of the NVEnergize project.

Director, Client Services & Total Rewards (2010- 2011)

Directs the development, planning, and administration of the company's employee benefits, compensation, and employee relations functions.

Manager, PR Client Services (2008 – 2010)

Develops, implements, manages and provides counsel on human resource strategies that support the business units.

Sierra Pacific Resources

Team Leader, Operations Accounting (2006 – 2008)

Manages accounting staff in the performance of various accounting and regulatory functions for the Operations Accounting staff in the fuel and purchased power department.

Staff Consultant, Operations Accounting (2006 – 2006)

Responsible for the direct oversight of all work performed by the Operations Accounting staff in the fuel and purchased power department.

Senior Accountant, Operations Accounting (2005 – 2005)

Responsible for the proper accounting and reporting of Sierra Pacific Power Company's gas transactions.

Lassen Municipal Utility District

General Manager (2003 – 2005)

Responsible for the management of all aspects of the 12,000-customer distribution utility including: human resources, accounting, finance, regulatory reporting, power purchases, public relations, engineering, operations and customer service.

Mt. Wheeler Power

Controller/Chief Operating Officer (1991 – 2002)

Managed accounting, finance, regulatory filing, data processing and human resources areas for a 4,600-customer utility, reporting to a Board of Directors. I began as an Accountant then was promoted to the Finance Manager, Controller then Controller/Chief Operating Officer as the area of responsibilities increased.

SYSCO/General Food Service

Assistant Controller (1987 – 1991)

Managed the accounts payable section and supervised the entire accounting department (payroll, accounts payable and logistics).

Education

Boise State University

May, 1989 - Bachelor of Business Administration, Management

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, EVELENE RICCI, 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: June 5, 2023

Evelene Ricci

ISMAEL SANCHEZ

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
2023 General Rate Case
Docket No. 23-06___

Prepared Direct Testimony of

Ismael Sanchez

Revenue Requirement

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

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

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

A. I have more than 27 years of experience at the Companies working in various roles and departments, including my current position since 2021. I graduated from New Mexico State University, Las Cruces with a Bachelor of Science in Electrical Engineering in 1991 and a Master's in Electrical Engineering in 1992. A complete description of my professional background and experience is included in my Statement of Qualifications, **Exhibit Sanchez-Direct-1**.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR, TELECOMMUNICATIONS.

A. As Director of Telecommunications I oversee and lead the Telecommunication operation business unit and my responsibilities include construction, maintenance, and operations of the telecommunications assets for the Companies.

4. Q. WHAT ARE THE ROLES AND RESPONSIBILITIES FOR THE TELECOMMUNICATIONS TEAM?

A. The telecommunications team oversees, designs, constructs, and maintains the telecommunication system that provide the telecommunication infrastructure to enable the supervisory control and data acquisition ("SCADA") for the Company to ensure that the system operators can safely and effectively monitor and control the electric power system. This infrastructure also provides protection system communication aid (relay-to-relay) for the protection of transmission lines to enable the fastest possible clearing of transmission line power faults to maintain system stability and reduce the likelihood of asset failure due to faulted conditions. Company traffic, public safety radio, and smart meter data, among other services, are all supported by and move through the telecommunication system.

5. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring the following Exhibit:

Exhibit Sanchez Direct-1 Statement of Qualifications

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

A. Yes, I testified in the 2022 Sierra Pacific Power general rate case ("GRC"), Docket No. 22-06014.

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

A. I support the prudency and reasonableness of Nevada Power's investment in telecommunication networks and facilities since the end of the certification period in the last Nevada Power GRC. My testimony specifically discusses six individual major programs under my responsibility listed in **Table Sanchez-Direct-1**. The programs in the table have expenditures that are near or exceed $1 million.[1]

8. Q. WHY ARE ONLY MAJOR PROGRAMS SPECIFICALLY DISCUSSED IN YOUR TESTIMONY?

A. Descriptions of every program completed by the telecommunications team since June 1, 2020, would take hundreds of pages of testimony, and the documentation surrounding each program is quite voluminous. In GRC's, the Commission seeks prepared direct testimony addressing the details of and supporting expenditures on major programs. In previous GRC's the Commission has accepted the $1.0 million demarcation as appropriate for determining whether a program is "major." While not addressed in detail in my prepared direct testimony, the Company has also prepared program binders for smaller programs completed since June 1, 2020. As has been the Companies' practice for many rate case cycles, those binders (now in

[1] The MAS Project is slightly lower than the $1 million threshold but is included due to timing of preparing testimony.

electronic form) are available for review on the day this general rate review filing is made.

TABLE SANCHEZ-DIRECT-1

Program Category	Actuals 06/01/2020-12/31/2022	Estimate 01/01/2023-05/31/2023	Total
Evergreen Switch Replacement	$993,385	$246,741	$1,240,127
Constellation Radio Replacement	$2,287,775	($77,557)	$2,210,219
Remote Terminal Unit (RTU) Replacement Program	$1,303,765	$273,090	$1,576,855
Comm Battery Replacement	$1,795,702	$196,631	$1,992,333
General Fiber Replacement	$1,100,123	$25,566	$1,125,689
Multiple Address System (MAS) Remote Radio Replacement	$767,739	$186,298	$954,037
Grand Total	**$8,248,489**	**$850,771**	**$ 9,099,259**

9. Q. PLEASE DESCRIBE THE EVERGREEN SWITCH REPLACEMENT PROGRAM.

A. This program involved engineering, procurement, and construction for the installation of Ethernet Switches to replace Substation Ethernet equipment that is either non-compliant with Corporate Security Standards or is functionally obsolete. The program also includes the removal and decommissioning of the non-compliance and obsolete equipment which was replaced.

10. Q. WHY WAS THE PROGRAM NECESSARY?

A. This program is intended to address the heightened cyber security requirements by replacing equipment that did not meet Corporate Security Standards and replace functionally obsolete equipment. As a result of the upgrades, additional

functionality came with the newer equipment standards resulting in new and advance services for secure data, voice, and video communications, with Virtual Private Network ("VPN") key characteristics that can be setup to allow for different services depending on the application.

11. Q. WHAT WAS THE TOTAL COST OF THIS PROGRAM?

A. The Evergreen Switch Replacement program expenditures from June 1, 2020, through December 31, 2022, were $993,385. Estimated expenditures for this program for the period January 1, 2023, through May 31, 2023, are $246,741. The total program costs are $1,240,127.

12. Q. PLEASE DESCRIBE THE CONSTELLATION RADIO REPLACEMENT PROGRAM.

A. This program involves the upgrade of the existing Constellation microwave radios throughout Nevada Power's service territory. These radios provide much of the SCADA backhaul for remote assets, such as substations and reclosers, voice and data communications for district offices, communication paths for transmission line protection circuits, and paths for the public safety radios as part of the Nevada Shared Radio System. These Constellation radios have reached or surpassed their life cycles and the Company has been experiencing an increased rate of failure with these devices. The program replaces these radios with the new Aviat Eclipse Ethernet microwave radios. The new radios have increased capacity and capability to support both legacy communications protocols, while also enabling the use of modern Ethernet protocols, supporting the direction of the Company while allowing time for the transition.

13. Q. WHY WAS THE PROGRAM NECESSARY?

A. The existing Constellation radios have reached or surpassed their life cycles, and the Company is experiencing an increased rate of failure for these devices. Outages on the backhaul negatively impact the Company's ability to receive and control statuses of assets such as breakers, reclosers, relays, regulators, generators, and other key assets for operating the electric grid. Further, device failures delay communication aid for transmission line protection, thereby, slowing the clearing of transmission line faults. Replacement parts and manufacturer support for these existing radios is limited and becoming more challenging to obtain. Additionally, the existing radios have capacity and capability constraints, which the new radios do not. For example, the new radios have the capability for modern Ethernet protocols but still support legacy time division multiplexing systems, which are still prevalent throughout the Company's territory.

14. Q. WHAT WAS THE TOTAL COST OF THIS PROGRAM?

A. The total cost of the Constellation Radio Replacement program from June 1, 2020, through December 31, 2022, was $2,287,775. Estimated expenditures for this program for the period January 1, 2023, through May 31, 2023, are ($77,557). The total program costs are $2,210,219.

15. Q. PLEASE DESCRIBE THE REMOTE TERMINAL UNIT ("RTU") REPLACEMENT PROGRAM.

A. The RTU Replacement program upgrades end of life or high risk RTUs throughout the service territory. RTU are devices that collect and report system indications, receive and issue commands to equipment, and collect and report ongoing system information such as voltage, current and power among other critical information.

RTUs are critical for controlling and monitoring the grid as they operate as an aggregator for this supervisory and data information, and then communicate the combined data to the electric grid operations control centers. As a part of this program, RTUs are upgraded to modern units to expand functionality, improve troubleshooting capabilities, and reduce costs associated with maintaining older units.

16. Q. WHY WAS THIS PROGRAM NECESSARY?

A. This program is needed to maintain consistent and reliable control and awareness of the electric grid. As RTUs reach the end of their service life they begin to fail at an increased rate. Additionally, certain types of RTUs are no longer supported, serviced, or supplied by the manufacturers nor are these RTUs supported by modern communication equipment. Continuing with the RTU upgrade and replacement program will reduce the risk of frequent and longer outages to SCADA information causing a loss of visibility to the Energy Management System and operator remote control.

17. Q. WHAT WAS THE TOTAL COST OF THIS PROGRAM?

A. The RTU Replacement program expenditures for the period from June 1, 2020, through December 31, 2022, are $1,303,765. Estimated expenditures for this program for the period of June 1, 2023, through May 31, 2023, are $273,090. The total program costs are $1,576,855.

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18. Q. PLEASE DESCRIBE THE COMMUNICATION ("COMM") BATTERY AND CHARGER REPLACEMENT PROGRAM.

A. This program involved engineering, procurement, and construction for the installation of new batteries, chargers, and associated hardware at multiple sites throughout the Nevada Power service territory. Battery and charger systems provide direct current ("DC") power required for critical telecom equipment and also provide backup power in the event of power outages. The battery and charger equipment are a key piece of the communication network which allows the Companies to comply with North American Electric Reliability Corporation PRC-005-2 requiring that all transmission protection systems affecting the reliability of the bulk system to be maintained, tested and operational. It is imperative for the safe operation of the telecom system to ensure that there is DC power to operate the substation equipment or other components supported by the telecom system. This program also included the removal and decommissioning of existing, obsolete equipment which was replaced.

19. Q. WHY WAS THE PROGRAM NECESSARY?

A. Batteries are utilized throughout the telecom network to provide DC power to equipment and to provide backup during electrical outages. The program involved identifying and replacing batteries and associated equipment at telecommunication sites that have exceeded their lifetime effectiveness and reliability. When batteries at communication sites fail, the entire site is no longer operational. This program assesses the equipment and prioritized sites that needed replacement. Telecommunication sites are predominately remote mountain top facilities that require a backup battery and a generator due to the remote location and periodic loss of primary power to the site. This configuration is standard throughout the

industry. These batteries support the public safety radio system, as well as equipment that allows system control to monitor and control the operation of the electric delivery system.

20. Q. WHAT WAS THE TOTAL COST OF THIS PROGRAM?

A. The Comm Battery and Charger Replacement program expenditures from June 1, 2020, through December 31, 2022, were $1,795,702. Estimated expenditures for this program for the period January 1, 2023, through May 31, 2023, are $196,631. The total program costs are $1,992,333.

21. Q. PLEASE DESCRIBE THE GENERAL FIBER REPLACEMENT PROGRAM.

A The General Fiber Replacement program upgrades and replaces damaged fiber optic communications cables throughout the service territory. Fiber optic cables require routine replacement due to vandalism, breakage or cable failures. Fiber optic cable is the primary communication link within southern Nevada that provides highspeed communications for internal critical grid operations. The program identifies areas of the Company's system where cable requires replacement.

22. Q. WHY WAS THIS PROGRAM NECESSARY?

A. The General Fiber Replacement program is necessary to maintain continuous communications between the Company's facilities, which provides a safe and effective operations platform for electric grid operations.

23. Q. WHAT WAS THE TOTAL COST OF THIS PROGRAM?

A. The General Fiber Replacement program expenditures from June 1, 2020, through December 31, 2022, were $1,100,123. Estimated expenditures for this program for the period January 1, 2023, through May 31, 2023, are $25,566. The total program costs are $1,125,689.

24. Q. PLEASE DESCRIBE THE MULTI-ADDRESS SYSTEM ("MAS") REMOTE RADIO REPLACEMENT PROGRAM.

A. The MAS Remote Radio Replacement program replaces manufacturer discontinued MAS radios, including both master and remote radios, with current technology. The MAS radio system consists of a master radio transmitter/receiver unit and multiple remote radio transmitter/receiver units. A master unit can access or poll multiple remote units via a pair of transmit/receive frequencies. The MAS system is used for limited bandwidth applications and operates under a licensed Federal Communications Commission ("FCC") frequency pair. These radios are used to transport SCADA data from locations where no other backhaul options are currently available.

25. Q. WHY WAS THIS PROGRAM NECESSARY?

A. The MAS radio system replacement program is necessary because the original equipment manufacturer, General Electric, issued a manufacturer discontinuation in December 2016 for the MAS systems used by the Company. The new MAS system improves the radio coverage and system reliability. In addition, it supports higher bandwidth devices used in modern control systems along with data encryptions for security.

26. Q. WHAT WAS THE TOTAL COST OF THIS PROGRAM?

A. The MAS radio system replacement program expenditures from June 1, 2020, through December 31, 2022, were $767,739. Estimated expenditures for this program for the period January 1, 2023, through May 31, 2023, are $186,298. The total program cost is $954,037.

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

A. Yes.

EXHIBIT SANCHEZ-DIRECT-1

STATEMENT OF QUALIFICATIONS OF

Ismael Sanchez
Director, Telecommunication Operations
NV Energy
7155 S Lindell Road
Las Vegas, NV 89118
(702)402-5883
Ismael.Sanchez@nvenergy.com

My name is Ismael Sanchez. I am the Telecommunications Director for Sierra Pacific Power Company and Nevada Power d/b/a NV Energy ("Sierra" and collectively, the "Companies"). I graduated from New Mexico State University, Las Cruces with a Bachelor of Science in Electrical Engineering in 1991 and a Masters in Electrical Engineering in 1992.

PROFESSIONAL EXPERIENCE

2021 to Present **NV Energy** ***Director, Telecommunication Operations***
Oversee and lead the Telecommunication operation business unit. Includes communication and communication sites throughout Northern and Southern Nevada. Includes construction, maintenance and trouble response of the Telecommunication system in Nevada overseeing thirty-two employees. Develop annual and ten-year business plans. Includes, annual safety program, growth capital, operating capital, and maintenance programs. Establish the business unit's annual goals and metrics. Set and communicate telecommunications business strategy and vision.

2016 to 2021 **NV Energy** ***Director, Delivery Operations South***
Responsible for construction and maintenance for all of Southern Nevada. The responsibility included the execution, scheduling and inspection of the process to install and maintain the power lines. Responsible for developing long term plans and strategies to optimize workforce and strategize reliability. Provided plans, processes, targets and implementation and feedback mechanisms, or tools for establishing best practice operations and maintenance. Developed and monitored industry and internal benchmarks to measure continuous improvements in financial and system performance. Monitored and enforced all compliance requirements for area of responsibility. Provided support for compliance audit activities and developed long term plans and budgetary requirements to support these plans.

2014 to 2016 **NV Energy** ***Manager, Line Const. and Maint.***
Managed the construction and maintenance of transmission and distribution lines in Southern Nevada. Responsible for establishing philosophy, standards, and procedures in Southern Nevada for the installation of transmission and distribution electrical facilities. Ensured proper maintenance procedures were adhered to by following schedules developed to optimize system reliability and conformance. On-call responsibilities.

2008 to 2014 **NV Energy** ***Program Manager, O&M EWAM***
Responsible for a cross functional team to develop requirements within the allotted cost and schedule for a large-scale enterprise work and asset management system. Responsible for a cross functional team to develop and execute the user acceptance testing within the allotted cost and schedule for the enterprise work and asset management system. Developed and executed a multi month project including the requirement gathering, solution, testing and deployment within the allotted cost and schedule.

2006 to 2008 **NV Energy** ***Manager, Substation Const. and Maint.***
Responsible for a team of twenty-seven employees that constructed new substations, maintained substations, and replaced aging or failed substation equipment. Managed the preventative maintenance program through Cascade database. Coordinated and executed several large-scale equipment replacements. Reviewed, logged and trended dissolved gas analysis. Troubleshot all substation equipment. Developed and executed a reliability centered maintenance program to effectively maintain the fleet of substation assets. On-call responsibilities.

1999 to 2006 **NV Energy** ***Team Leader, Reg. Maint Supp. Services***
Responsible for a team of twelve employees in northern and southern Nevada responsible for optimizing power system reliability. Responsible for optimizing statewide power system reliability by designing and implementing innovative programs. Provided and implemented recommendations to maximize efficiencies and power system reliability through synergy of methods and work practices, for example mirroring the vegetation management program in southern Nevada to Northern Nevada Region. On-call responsibilities.

1998 to 1999 **NV Energy** ***Team Leader, T&D Maint. Services NPC***
Responsible for a team of fifteen employees in southern Nevada responsible for optimizing power system reliability. Designed and implemented innovative programs to continually improve the safe operation and reliability of the transmission and distribution system. Provided leadership and accountability for all activities related to the provision of operation and maintenance support services including analytical support; transmission, substation and distribution maintenance programs and schedules; and system improvement construction projects. On-call responsibilities.

1997 to 1998 **NV Energy** ***Distribution Maint. Coordinator, NPC***
Responsible for developing and implementing various transmission and distribution maintenance programs to improve safety and optimize reliability in Southern Nevada. Provided oversight and successfully met various time frames for existing maintenance programs. Provided management updates regularly through budgetary reports and system performance reports

1995 to 1997 **NV Energy** ***Engineer III, Distribution Standards NPC***
Responsible for maintaining the distribution standards including the material, installation and electric service requirements volumes. Provided review to ensure that that each standard was in accordance with applicable codes and safety requirements. Ensured acceptability and feasibility to various alternatives by ensuring involvement by various parties with a vested interest. Incorporated new materials and work methods into applicable standards or created new standards.

EDUCATION

New Mexico State University – Las Cruces, NM
Master of Business Administration – 1992
New Mexico State University – Las Cruces, NM
Bachelor of Science in Electrical Engineering – 1991

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, ISMAEL SANCHEZ, 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: June 5, 2023

Josh Langdon for Ismael Sanchez

CHRISTOPHER SARDA

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 23-06___
2023 General Rate Case

Prepared Direct Testimony of

Christopher Sarda

Revenue Requirement

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

A. My name is Christopher Sarda. My current position is Financial Analysis Manager for Nevada Power Company d/b/a NV Energy ("Nevada Power" or the "Company") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies"). My business address is 6226 West Sahara Avenue, MS #51, Las Vegas, NV 89146. I am filing testimony on behalf of Nevada Power.

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

A. I have worked in the utility industry for two years, all of that time in Treasury and Financial Planning and Analysis. My statement of qualifications is attached as **Exhibit Sarda-Direct-1**.

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3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS FINANCIAL ANALYSIS MANAGER.

A. As Financial Analysis Manager, my responsibilities include supporting various areas of the Company with analytical support from a finance and accounting perspective and I support financing, forecasting, and budgeting for the Company.

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

A. No. I have not previously testified before the Commission.

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

A. The purpose of my testimony is to explain the analysis related to the acquisition of assets for Nevada Power's fleet.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibits:

Exhibit Sarda-Direct-1 Statement of Qualifications

7. Q. PLEASE DESCRIBE THE FINANCIAL ANALYSIS PERFORMED TO DETERMINE WHETHER TO PURCHASE THE VEHICLES OR TO LEASE AND BUY AT END OF TERM.

A. In 2021, the Company conducted a present worth revenue requirement ("PWRR") analysis for Nevada Power's fleet additions using similar assumptions as were used for Sierra's 2022 general rate case ("GRC"), specifically, a 3 percent marginal cost of capital and a 19-year total vehicle useful life. Under that assumption for this rate making scenario, purchasing the vehicles was more favorable than leasing the

vehicles and then buying at the end of term by $575,147 in PWRR terms. PWRR for the lease then buy scenario equaled $7.0 million and the PWRR for the purchase scenario equaled $6.4 million. See **Table Sarda Direct-1**.

Table Sarda Direct-1

		At 3.00% Cost of Capital
PWRR of Purchasing	$	6,407,631
PWRR of Leasing w/End of Term Buyout	$	6,982,777
Favorable (Unfavorable) Variance of Purchasing	$	575,147

Analysis of prospective purchases for 2021 with perfect rate making

8. Q. PLEASE DESCRIBE HOW THE FINANCIAL ANALYSIS WOULD CHANGE IF THE CURRENT WEIGHTED AVERAGE COST OF CAPITAL WAS USED.

A. If the Company were to use a cost of capital of 7.14 percent, the PWRR for the lease then buy scenario would have been favorable versus the purchasing scenario by $437,613 in PWRR terms. The PWRR for the lease then buy scenario would equal $5.9 million and the purchasing scenario would equal $6.3 million. See **Table Sarda-Direct-2**.

Table Sarda Direct-2

		At 7.14% Cost of Capital
PWRR of Purchasing	$	6,319,414
PWRR of Leasing w/End of Term Buyout	$	5,881,802
Favorable (Unfavorable) Variance of Purchasing	$	(437,613)

Analysis of prospective purchases for 2021 with perfect rate making

9. Q. PLEASE DESCRIBE THE FINANCIAL ANALYSIS PERFORMED TO BUY OUT EXISTING LEASES.

A. A present value calculation was used to compare the expected payments, end of term buyout, and associated fees for continuing the leases as contracted versus the cost of early lease termination. Based on that analysis, the Company decided to continue its leases with all vendors with one exception, RBS Citizens. For the two vehicles that were bought out from RBS Citizens, the marginal cost of capital between the two options was immaterial and close to neutral, a $435 favorable variance towards continuing the lease as compared to early termination, when using a 3 percent cost of capital. The net present value ("NPV") for continuing the lease was $191,855 versus $192,290 for a planned early termination of the lease in the June 2021 buyout timeframe. Using a 7.14 percent cost of capital scenario, continuing the lease would have been favorable by $7,794. The NPV for continuing the lease would have been $184,495 versus $192,290 for early termination of the lease in the expected June 2021 buyout timeframe. With the 3.00 percent cost of capital yielding an immaterial difference, the Company decided to terminate its leases early and end its leasing relationship with the lessor – RBS Citizens.

10. Q. HOW HAS THE FINANCIAL ANALYSIS PERFORMED BY NEVADA POWER RELATED TO ITS FLEET OF VEHICLES EVOLVED SINCE THE SIERRA GRC ORDER?

A. After the Modified Final Order in the Sierra GRC was issued on February 16, 2023,[1] The Company re-evaluated its fleet analysis. After considering the quantitative and qualitative factors, the Company created a policy to ensure a

[1] Docket No. 22-06014.

flexible approach when evaluating lease then buy and purchasing options. This approach takes into consideration the suggested vehicle acquisition method as indicated from the PWRR analysis, while also allowing for the consideration of other factors such as the availability of specific vehicle models or the length of time required to acquire a particular vehicle. Nevada Power intends to apply the flexible approach of purchasing some vehicles and leasing then buying other vehicles for fleet acquisitions, depending on the outcome of the analysis. The updated analysis by Nevada Power continues to utilize a PWRR model, but also includes a focus on vehicles of similar class, size, and use to better capture the different lease product offerings from available vendors. Variables considered include the length of lease, fees, and the types of leases depending on the vehicles/equipment being considered for acquisition.

To that end, Nevada Power recently conducted an updated forward-looking PWRR analysis for the Company's Large Operational Vehicles ("LOV")s. In this instance, the analysis for future 2023 purchases show a $472,000 favorable PWRR result for customers by utilizing a lease then buy approach. The analysis for the LOVs used a 7.14 percent cost of capital and a useful life of 14 years based on historical vehicle retirement age. A similar analysis shows a $98,000 favorable PWRR result for purchasing the Company's light duty vehicles ("LDV") obtained from Nevada dealerships as compared to a lease then buy approach of these same vehicles. The

Table Sarda Direct-3

	2023 PWRR ANALYSIS		
	LOV	LDV	TOTAL
Purchasing	$ 4,792,609	$ 1,593,659	$ 6,386,268
Lease + Buy (at end of lease)	4,320,714	1,691,787	6,012,501
Favorable (Unfavorable) Variance of Leasing	$ 471,895	$ (98,128)	$ 373,768

LOV = Large Operational Vehicles, LDV = Light Duty Vehicles

LOVs are assumed leased for 7 years, LDVs are assumed leased for 5 years; at lease end both vehicle types are bought and used for an additional 7 years

analysis for LDVs used a 7.14 percent cost of capital and a useful life of 12 years based on historical vehicle retirement age. See **Table Sarda-Direct-3**.

The Company's analysis ensures a flexible approach in which both purchasing and leasing (with subsequent end of lease buyouts) is considered with regard to PWRR favorability in conjunction with a focus on other qualitative factors.

11. Q. WHEN CONSIDERING THE EVOLUTION OF THE FLEET ACQUISITION STRATEGY, SHOULD NEVADA POWER BE SUBJECT TO THE SAME RETURN LIMITATION ON ITS FLEET VEHICLES AS SIERRA?

A. No. The Company understood the Commission's order in Sierra's 2022 GRC and re-evaluated its strategy. First, it revamped its analysis and ensured it was more realistic to what would happen, such as the assumed lease costs and the changing economic environment. Second, it developed a policy that relies upon both quantitative and qualitative analysis. Since there is no industry standard to evaluate lease then buy scenarios versus purchase only scenarios, the Company believes all costs stemming from these determinations should be recovered as these decisions are part of the normal course of business. Furthermore, the vehicles acquired are used and useful. Based on the timing of the Commission's order in Sierra's 2022 GRC, this analysis reevaluation did not occur in time to impact vehicle purchases in 2021 and 2022, which were purchased based on the original 3 percent cost of capital analysis conducted in 2021.

12. Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

EXHIBIT SARDA-DIRECT-1

CHRISTOPHER SARDA
FINANCIAL ANALYSIS MANAGER
NV Energy, Inc.
6226 West Sahara Avenue
Las Vegas, NV 89129

Summary of Qualifications

Mr. Sarda has been Financial Planning & Analysis Manager of NV Energy, Inc. ("NVE") since April 2021, which began his career in the regulated energy industry. Including his time at NVE he has over 15 years of experience across Corporate Finance, Financial Planning, and Business Management.

Employment History

NV Energy, Inc.
2021 to present
Financial Planning & Analysis Manager
Responsibilities include financial leadership, analysis, and oversight of many projects across the companies including budgeting, forecasting and financing business plans, analyzing property sales and purchases, fleet, and supporting financial modeling including ad-hoc and new projects that have not standardized.

ASNY Company LLC
2019 to 2021
Senior Financial Analyst

Blue Moon Advisors
2019
Senior Manager of Finance

National Credit Center
2018 to 2019
Senior Financial Analyst – Internal Audit

Amazon/Zappos
2016 to June 2018
Senior Finance & Operations Program Manager

American Kiosk Management
2013 to June 2015
Senior Finance & Operations Program Manager

Steinberg Diagnostic
2009 to June 2011
Project Manager

Optima Language School
2007 to June 2009
English Teacher Overseas

Sarda Auto Sales
2000 to June 2002
Owner & Manager

Education

University of Nevada, Las Vegas
Bachelor of Science in Business Administration, Finance, May 2013

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, CHRISTOPHER SARDA, 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: June 5, 2023

CHRISTOPHER SARDA