

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their joint 2025-2044 integrated resource plan, for the three year Action Plan period 2025-2027, and the Energy Supply Plan period of 2025-2027.

Docket No. 24-05____

VOLUME 4 OF 29

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

DESCRIPTION	PAGE NUMBER
TESTIMONY	
Eric Schwarzrock	2
Jimmy Daghljan	20
Sean Spitzer	33
Mark Warden	62
Kimberly Williams	72
Nicolai Schlag	155
Dr. David Harrison	225
Michael Behrens (Redacted)	318
Christopher Sarda	345
Janet Wells	354

ERIC SCHWARZROCK

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

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

Prepared Direct Testimony of

Eric Schwarzrock

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

A. My name is Eric Schwarzrock. I am the Vice President, Customer Solutions and Projects for Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, the “Companies” or “NV Energy”). My business address is 6100 Neil Road, Reno, Nevada. I am filing testimony on behalf of the Companies.

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

A. I have a Bachelor of Science degree in Electrical Engineering and a Master of Business Administration, both from the University of Nevada, Reno. I am a registered Professional Engineer. I have 20 years of experience in the electric utility industry. I have experience in operations, planning, engineering, asset management, project management and project development. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Schwarzrock-Direct-1**.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

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

A. I am responsible for transmission and distribution (“T&D”) planning, engineering, and project management for the Companies. Largely, my business unit works together with Electric Delivery and Transmission to operate the T&D business for the Companies.

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

A. Yes, I have testified in previous filings, including most recently Docket No. 22-06014, the 2022 general rate case for Sierra.

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

A. Because of the increase in large load requests, I am providing a summary for how the Companies work with customers to connect large loads, such as data centers, and to provide context on our processes.

6. Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I discuss the type of customer connections and the tariffs that guide those connections. Second, I focus on the differences between connecting small and large loads. Third, I discuss the process to initiate, study, and enter into agreements for these connections. Fourth, I describe how cost responsibilities are governed. Fifth, I discuss how higher risk projects are determined and categorized. Sixth, I discuss how those risks are addressed. Lastly, I address the large load additions, particularly

1 data centers, the Companies are currently experiencing and the different types of
2 data centers entering Nevada.

3
4 To be clear, this testimony is intended to be a summary of the connection process
5 with a focus on large loads and the growth driven by data centers. It is not intended
6 to be inclusive to all the scenarios that exist.

7
8 **7. Q. WHAT TYPE OF CONNECTIONS ARE MADE WITH THE T&D**
9 **SYSTEM AND WHAT TARIFFS ARE APPLICABLE TO THOSE**
10 **CONNECTIONS?**

11 A. There are two types of connections made with the T&D system: supply and load.
12 Supply includes, but is not limited to, thermal generation, solar, wind, geothermal,
13 and battery. These connections supply electricity to the grid. Load includes, but is
14 not limited to, residential, multi-family, commercial, and industrial. For the past
15 decade or so, this load has included data centers. These connections draw electricity
16 from the grid.

17
18 Both types of connections will connect to either the transmission or distribution
19 system. When connecting with the T&D system, there are two sets of applicable
20 tariffs: the federal tariff and the state tariffs.

21
22 The federal tariff is the Open Access Transmission Tariff ("OATT"), which
23 governs how customers access the transmission system. The OATT primarily
24 governs two basic services, transmission service and generator interconnections.
25 Simply put, the transmission service portion of the OATT guides how third-party,
26 non-native load customers, called "Network Customers" can utilize the
27

1 transmission system to move electricity from designated Network Resources to
2 their Network Loads, or to move electricity from one point of the transmission
3 system to another, typically to wheel through the Companies' transmission system.
4 The generator interconnection portion of the OATT governs the interconnection
5 process including, but not limited to, how supply resources can interconnect to the
6 system. The OATT governs the transmission service and generator interconnection
7 processes as well as the cost responsibilities between the utility and the applicant.
8 More detailed information about these services is described in the testimony
9 provided by Kiley Moore.

10
11 The state tariffs are a collection of rules that define the relationship between a utility
12 and its customers. Each utility, including the Companies, has its own tariff, which
13 consists of distinct rules. Rules address service area, rates, allocation of costs for
14 line extensions, allocation of costs for new customer connections, requirements for
15 new customers, and other issues which define the responsibilities and authorities of
16 the utility. At the Companies, Rule 9 is the rule that governs line extensions, how
17 customers connect to the T&D system, and the cost responsibilities between the
18 utility and the applicant.

19
20 Therefore, cost responsibilities when connecting supply or load to the T&D system
21 are determined by two sets of rules: the OATT governs the responsibilities for
22 interconnecting supply to the system, as well as the transmission facilities required
23 to get Network Customer supply to their load, and Rule 9 governs the
24 responsibilities for connecting load to the Companies' grid.

8. Q. **WHAT ARE THE DIFFERENCES FOR CONNECTING LARGE VERSUS SMALL LOADS?**

A. While the process is largely similar, some of the departments and terms used for the connection process are different when connecting to the transmission system versus the distribution system. Because most large loads connect to the transmission system, I will focus my response on that process, but I will reference differences when connecting to the distribution system as well. In either case, the connection process is governed by Rule 9.

Per Rule 9, the customer selects the standard voltage in which it will receive service. The costs to make those connections and the rates applied to the different types of service are considerations some customers evaluate when making these requests.

When considering larger loads, there is no brightline criteria for connecting to the distribution versus the transmission system. Most customers connecting loads less than 10-megawatts are connecting to the distribution system. However, there are some customers that do seek to connect to the transmission system for loads that are less than 10-megawatts. Similarly, for loads greater than 10-megawatts, most customers connect to the transmission system, but some do connect to the distribution system. So, while there is no brightline criteria, 10-megawatts is a reasonable value to consider when loads are connecting to either the transmission or distribution system, respectively.

The Companies seek to be flexible when considering the customer's request, while in either case, providing solutions that are the Minimum Requirements to serve per

the Companies' standards. For projects anticipated to be above 10-megawatts, most are requesting to connect to the transmission system.

9. Q. ARE THE PROCESSES AND RESPONSIBILITIES LARGELY SIMILAR BETWEEN THE OATT AND RULE 9?

A. Yes, while the definitions and terms are different, the general process and responsibilities are principally the same.

Initiation: In all cases, the process starts with a customer submitting information about its project. This includes, but is not limited to, information about the applicant, location for the project, supply or load, electrical size, target in-service date, and other key information. For each type of connection, the Companies' standard form is used to facilitate the collection of this information, and personnel help customers with completing these forms. For large projects connecting to the transmission system, this form is called a Project Data Sheet, and it is collected by our Business Development teams. For smaller projects connecting to the distribution system, the form is called a Project Information Sheet, and this can be collected electronically through our New Business Portal, or through our Distribution Design Services team.

Study: Once the necessary information is collected, in many cases, a study agreement and any applicable fee are prepared. Once the customers sign the study agreement and submit the necessary fee, their place in the queue is reserved. While managed independently, this queue process is utilized for both supply and load connections. An exception to this study agreement and fee exists for load requests connecting to the distribution system, where the Companies will provide at least

one free study and summary of results. For projects connecting to the transmission system, these study agreements are called Engineering Study Agreements, and the studies are performed by the transmission planning department. For projects connecting to the distribution system, these study agreements are called Design Initiation Agreements, and the studies are performed by the distribution planning departments. These studies and the subsequent results are provided back to the customers to provide a high level, non-binding, summary of what will be required to perform their requested connection, most notably the facilities required to make the electrical connection. This summary can be used by customers to make business decisions about whether to proceed, not proceed, or to adjust their request. For large projects connecting to the transmission system, the study itself is called a Transmission Load Study and the study results, and associated information such as cost estimates and schedule, are provided in a Discovery Package sent back to the customer by the Project Development team. For projects connecting to the distribution system, the study results are documented in a Planning Memo which is provided back to the customer by their assigned Project Coordinator from the Distribution Design Services team. In all cases, there is a timeframe for how long a customer can remain in this study phase before moving to the next phase.

Agreements: Whether the connection is a transmission request, and the Discovery Package has been provided to the customer, or a distribution request and the comparable Planning Memo has been provided to the customer, before the Companies move to the construction phases, another agreement must be completed. These agreements include the binding terms between the customer and the Companies for completing the project. In all cases, these agreements include, but are not limited to, the facilities required to make the connection, responsibilities for

1 necessary easements and permits, and the cost responsibilities for the project. For
2 projects connecting to the transmission system where the design package would be
3 of considerable size and complexity, the design package is completed after the
4 agreements are signed by both parties. For projects connecting to the distribution
5 system, the designs are completed and included as part of the agreement. For large
6 projects, this agreement will be either a High Voltage Distribution Agreement
7 (“HVD Agreement”) or the combination of a Master Planned Community Umbrella
8 Agreement (“Umbrella Agreement”) and Substation / High Voltage Distribution
9 Agreement (“SHVD Agreement”). For projects connecting to the distribution
10 system, this agreement will be either a Large Project Line Extension Agreement, or
11 the combination of an Umbrella Agreement and SHVD Agreement, with
12 subsequent Addendum and Line Extension Agreements. The framework for these
13 agreements is provided via Rule 9 and is overseen by the Project Development team
14 or the Distribution Design Services team, respectively.

15
16 Once these agreements, the associated designs, the associated permits/easements,
17 and the associated government approvals are in place for the required facilities, the
18 projects move to construction. Once construction is complete and the facilities are
19 approved for energization, meters are set, and the projects are energized.

20
21 NV Energy’s Lands team supports the required land rights, and NV Energy’s
22 construction teams support the construction and meter set.

23
24 Regardless of whether the new load is a wholesale transmission customer under
25 NV Energy’s OATT or a new load that will be a part of native load, the connection
26 process is governed by Rule 9. For wholesale transmission customer’s loads, the
27

customer must also make a corresponding application for transmission service to serve the new load. The transmission service process is managed separately from the evaluation of the load addition. Although the load addition is evaluated under Rule 9, the wholesale transmission customer load addition is governed under the OATT in conjunction with the Rule 9 requirements. These third-party non-native load additions are managed by the Project Development team, and the transmission service is managed by the Transmission Business Services team.

For generator interconnections, this agreement will be either a Small or Large Generator Interconnection Agreement (“SGIA” or “LGIA”). For transmission services this agreement will be some form of a Transmission Service Agreement (“TSA”), and, in any case, these agreements would be overseen by our Transmission Business Services team. The framework for these agreements is provided via the OATT.

10. Q. HOW ARE COST RESPONSIBILITIES DETERMINED?

A. The utility and applicant cost responsibilities are governed by the OATT and Rule 9.

11. Q. WHAT PROVISIONS EXIST TO IDENTIFY AND CATEGORIZE HIGHER RISK PROJECTS?

A. Rule 9 includes a provision defined as Abnormal Risk.

Abnormal Risk is defined as: Abnormal or unusual risk, as it pertains to Rule 9, includes the risk that i) project costs will not be fully collected from project developers, and ii) new loads enabled by line extensions will be reduced or

terminated – and consequently will not generate the required rate revenue to pay for the cost of the line extension over its life. Factors that may affect the above project costs and revenue recovery include but are not limited to the project developer's or premise occupant's business and credit risk, broader industry and technology risk, and premise re-occupancy risk.

Projects anticipated to have higher or unusual risk are submitted to NV Energy's risk department for review. The risk department, in collaboration with the Project Developer or Project Coordinator, will determine if the project is Abnormal Risk. Many large projects are determined to be Abnormal Risk.

12. Q. WHAT PROVISIONS ARE IN PLACE TO MITIGATE RISK TO EXISTING CUSTOMERS?

A. Once Abnormal Risk is determined, per Rule 9, there are then several mechanisms that are used to help mitigate the risk. Those strategies include, but are not limited to:

- requiring security for up to 100 percent of the utility investment,
- implementing a phased approach to construct the connection facilities over time as the load materializes,
- establishing agreement milestones to ensure the Applicant and Company are progressing together,
- implementing reduction of service charge provisions in case an Applicant's load is short,
- requiring an advance subject to potential refund for the utility investment,
- for those customers already in service, obtaining annual updated load forecasts to advise transmission planning studies so models reflect actual

loads and revised customer stated load forecasts, and supplemental phases/projects are only triggered when required, and

- monthly and annual review of large customer loads and progress towards full build-out.

13. Q. DO THE COMPANIES EVALUATE HOW OTHER UTILITIES CONNECT DATA CENTERS?

A. Yes. The Companies have collaborated with several other utilities to evaluate best practices. Some of these utilities include Arizona Public Services, Salt River Project, Georgia Power, AltaLink, Rocky Mountain Power, MidAmerican Energy Company, Pacific Power, and Dominion Energy the home of the ‘data center alley’ in Virginia. The Companies believe its approach for the connecting facilities is slightly more conservative but balanced compared to the other utilities evaluated to support development while protecting existing customers because of the provisions implemented above in Q&A 12.

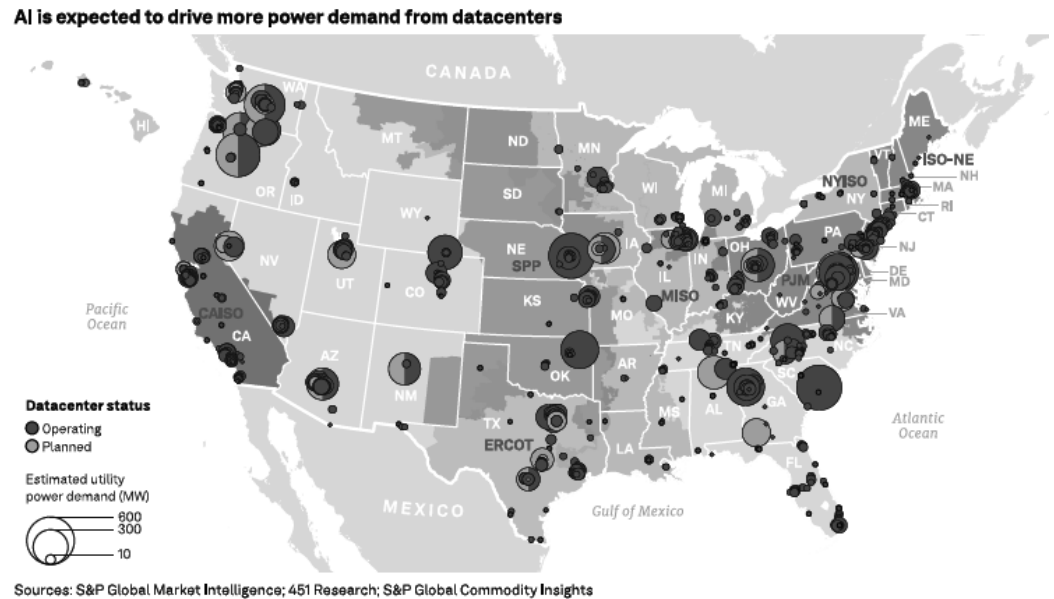
Additionally, information about discounting the load forecast is described in the testimony provided by Tim Pollard.

That said, the Companies continue to evaluate opportunities to improve.

14. Q. APPROXIMATELY HOW MUCH NEW LOAD IS UNDER CONTRACT AND HOW MUCH ADDITIONAL LOAD HAS BEEN REQUESTED FOR STUDY?

A. Like much of the country, there is considerable interest and growth for data centers. Continued adoption of cloud services and the advancement of machine learning and

artificial intelligence is fueling that growth. Some publications indicate that data center demand will grow by some 10 percent a year through 2030.¹ The image² below forecasts the growth across the country and helps provide a visual for the impact nationwide.



In the past 12-months, the Companies have completed contracts for approximately 4-gigawatts of load. These projects are planned to be in service throughout the next several years with loads ramping over the next ten years or so. In addition, there is nearly six gigawatts of inquiry with a portion of that under study. While most of the interest and growth has been in northern Nevada, interest in southern Nevada is picking up. The Companies expect state-wide interest and growth to continue.

¹ “Investing in the Rising Data Center Economy”, McKinsey & Company, January 2023:

<https://www.mckinsey.com/industries/technology-media-and-telecommunications/our-insights/investing-in-the-rising-data-center-economy>

² “Megawatt Daily”, Platts S&P Global Commodity Insights, October 16, 2023:

<https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/electric-power/101623-power-of-ai-wild-predictions-of-power-demand-from-ai-put-industry-on-edge>

15. Q. WHAT TYPE OF DATA CENTERS ARE THERE?

A. For the most part, there are three types of data centers or data center development: hyperscalers, co-locators, and master planned data center developers. Hyperscalers are entities that build and use the data center for their own purpose. These companies are typically household names. Co-locators are data centers that build and own the facility but lease space within that facility to other companies who own and use the servers. Neither of these data centers are new to Nevada. Additionally, there are master planned data center developers. Like a master planned community for residential or commercial properties, master planned data center developers create a community which include the utilities and preplanned sites for hyperscalers and co-locators to build their data centers. The Companies have been working with all three types.

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

A. Yes.

EXHIBIT SCHWARZROCK-DIRECT-1

STATEMENT OF QUALIFICATIONS OF
Eric A. Schwarzrock PE
Vice President, Customer Solutions and Projects
NV Energy
6100 Neil Rd.
Reno, NV 89511
(775)834-4443
Eric.Schwarzrock@nvenergy.com

My name is Eric Schwarzrock. I am the Vice President for Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy (the “Companies”). I graduated from the University of Nevada, Reno with a Bachelor of Science in Electrical Engineering in 2005 and a Masters in Business Administration in 2013. I am a licensed professional engineer in the State of Nevada (#020272).

PROFESSIONAL EXPERIENCE

2022-present	NV Energy <i>Vice President, Customer Solutions and Projects</i> Oversee and lead the planning, engineering, project teams for the transmission and distribution system. This includes both the transmission and distribution planning teams. The standards team, as well as the design and project management teams for the transmission and distribution teams. Collectively, these teams work with the Electric Delivery and Transmission business units to operate the T&D system.
2020 to 2022	NV Energy <i>Director, T&D Engineering</i> Oversee and lead the transmission and distribution engineering teams including the substation, transmission/civil, telecommunications, standards and asset management engineering teams. 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.
2017 to 2020	NV Energy <i>Director, Substation and Technical Operations</i> Oversee and lead the substation and technical operations business unit. Includes 228 substations throughout northern Nevada. Includes substation design engineering, system protection engineering, general construction, substation operations, and system protection operations. 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 substation business strategy and vision.
2015 to 2017	NV Energy <i>Director, NERC and CIP Compliance</i> Oversaw company compliance program regarding North American Electric Reliability Corporation (NERC) reliability standards. Expanded

compliance program to include standards development, implementation, and monitoring functions including technical support throughout the life of the standard. Led NV Energy through the 2017 Western Electric Coordination Council (WECC) audit. Oversaw the creation NV Energy's Critical Infrastructure Protection (CIP) "CIPv5" program.

2012 to 2015

NV Energy ***Manager, System Protection North***

Responsible for establishing the system protection philosophy, standards, and procedures on a statewide basis for protection of transmission and distribution electrical facilities. Developed and ensured mandated (NERC) compliance, consistency and standardization of system protection philosophy throughout northern Nevada including protection scheme designs, relaying and associated equipment, selection, relay settings, databases and testing. Prioritized and scheduled capital, preventative maintenance and emergency work efforts of a staff of system protection engineers and relay technicians to accomplish capital and maintenance objectives.

2009 to 2012

NV Energy ***System Protection Engineer***

Designed and tested advanced protection schemes, substation automation schemes, analyzed event reports, prepared and oversaw projects of all sizes and complexity (4kV to 345kV). Led the process towards better standardization and simplification of advanced logic, settings, rack design and testing procedures. Served as a subject matter expert for the compliance of the PRC series (NERC). On-call responsibilities.

2005 to 2009

NV Energy ***Substation Field Engineer***

Wrote protection system test plans. Wrote test plans for breakers, transformers, regulators, tap changers and other substation equipment. Managed the preventative maintenance program through Cascade database. Partnered on battery bank testing and bank replacement projects. Reviewed, logged and trended dissolved gas analysis. Troubleshoot all substation equipment. On-call responsibilities.

EDUCATION

University of Nevada- Reno, NV

Master of Business Administration – 2013

University of Nevada-Reno, NV

Bachelor of Science in Electrical Engineering – 2005

AFFIRMATION

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

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

Date: May 31, 2024


ERIC SCHWARZROCK

JIMMY DAGHLIAN

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

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

Prepared Direct Testimony of

Jimmy Daghljan

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

A. My name is Jimmy Daghljan. I am the Vice President of Renewables for Sierra Pacific Power Company d/b/a NV Energy (“Sierra”) and Nevada Power Company d/b/a NV Energy (“Nevada Power” and, together with Sierra, the “Companies”). My business address is 7155 S. Lindell Road in Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

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

A. I hold Bachelor and Master of Science degrees in Chemical Engineering from the University of Utah and a Master of Business Administration degree from Westminster College in 2006. I have worked for the Companies since 2012 in various capacities including Director Generation Support, Director Delivery Operations South and my current role as Vice President, Renewables. My responsibilities include overseeing origination and development of renewable generating and storage resources, procurement and contract negotiations for renewable and non-renewable energy resources, and engineering and project

management to deliver renewable and storage resources. My team also supports contract management tasks for the Companies' owned and contracted resources. My statement of qualifications is attached as **Exhibit Daghlia-Direct-1**.

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

A. In my current position, I lead a staff of directors that manage all energy and capacity procurement, asset acquisitions, customer programs, contract management and renewables development projects for the Companies.

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

A. Yes. Most recently, I provided written testimony in Docket No. 23-08015, Fifth Amendment to the 2021 Joint Integrated Resource Plan (2022-2041).

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

A. The purpose of my testimony is to provide an update regarding the renewable energy landscape in Nevada with support for continued deployment of both company-owned and contracted renewable energy projects and the importance of the transmission infrastructure development in furtherance of that deployment. I also discuss the renewable energy supply pipeline for the already contracted resources and provide support for the solar and battery energy storage system ("BESS") power purchase agreements ("PPAs"), and the geothermal PPA included for the Commission's approval in this filing.

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

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

Exhibit Daghlain-Direct-1 – Statement of Qualifications

7. Q. PLEASE DESCRIBE THE RENEWABLE ENERGY LANDSCAPE IN NEVADA AS IT IMPACTS THE COMPANIES' RENEWABLE ENERGY SUPPLY PIPELINE.

A. Nevada is entering a critical period of renewable energy buildout, driven by substantial load growth and compounded by the increasing RPS compliance requirement. While Nevada is fortunate enough to have some of the greatest solar and geothermal potential in the country, the State faces challenges to developing its renewable potential in the near term to meet the State's energy policies.

Foremost, the continued expansion of renewable energy in Nevada necessary to achieve the RPS requirement is not possible without additional transmission infrastructure. Availability of land sited in proximity to transmission lines, and associated acquisition and permitting timelines, is also a prime constraint to bringing projects online in the near term. Moreover, project developers continue to cite supply chain constrictions in obtaining major equipment, with lead times in excess of two years for components such as circuit breakers, transformers, panels and battery. Exacerbating the timeline, several previously approved renewable projects were cancelled. Thus, the Companies are focused on seeing that projects brought forth for approval have presented a clear path to transmit power to load on the schedules proposed to meet the stated commercial operation date ("COD"), while demonstrating a market-competitive cost. To achieve this, the Companies actively continue to improve the RFP procurement process with enhanced due

diligence from internal subject matter experts that target key project proposal aspects such as available transmission capacity and equipment supply control. While the Companies have built a diverse and robust portfolio of renewable projects through both long-term PPAs and utility-owned renewable projects, a sustained supply of renewable energy projects is essential to meet the Renewable Portfolio Standard (“RPS”) requirement.

8. Q. PLEASE DESCRIBE THE IMPACT THAT THE COMPLETION OF THE GREENLINK TRANSMISSION PROJECT WILL HAVE ON RENEWABLE ENERGY DEVELOPMENT IN NEVADA.

A. The completion of the Greenlink transmission project will unlock renewable energy development potential that is currently not accessible due to lack of necessary transmission infrastructure, such as the 700 MW Libra Solar & Storage PPA presented in this filing, as well as future named placeholders including the 800 MW Amargosa Solar and 1,000 MW White Pine Pumped Hydro Storage projects. Greenlink offers new transmission lines dedicated to renewable projects that will enable a critical state-wide transmission connection between northern and southern Nevada. Greenlink will, therefore, allow for further diversification of the Companies’ renewable and thermal resources in both the north and south.

9. Q. IF THE GREENLINK TRANSMISSION PROJECT IS NOT COMPLETED, PLEASE DESCRIBE THE IMPACT ON RENEWABLE ENERGY DEVELOPMENT IN NEVADA.

A. Without Greenlink, new renewable project development opportunities will be constrained. If Greenlink is not completed, other transmission projects will be needed to achieve the same goal of unlocking transmission capacity along corridors

of high-potential renewable energy project areas. Alternatively, new renewable energy projects will require the construction of dedicated transmission from generation locations to load. The lengthy permitting and construction timeline for equivalent transmission infrastructure would add heightened risk to the Companies' ability to comply with the RPS if Greenlink is not completed.

10. Q. PLEASE DESCRIBE THE COMPANIES' OUTLOOK FOR ANY SPECIFIC POTENTIAL CONCERNS ASSOCIATED WITH ALREADY CONTRACTED RESOURCES.

A. In addition to the cancellation of the Hot Pot and Iron Point projects discussed in the Companies' Fourth Amendment to the 2021 Joint Integrated Resource Plan, as well as the Chuckwalla and Southern Bighorn solar discussed in the Companies' 5th Amendment to the 2021 Joint Integrated Resource Plan, the Boulder Solar III PPA¹ recently terminated, and, as previously communicated during the Fifth Amendment hearing, the Eavor geothermal project will not be completed as contracted. There is the risk that one or more of the other approved pipeline PPAs could be delayed or, worse yet, canceled by the developer. To this end, the Companies continue to evaluate existing and pipeline projects and take corrective actions to remain on track to meet all their renewable goals, commitments, and statutory requirements.

///

///

¹ Approved in Docket No. 20-07023.

11. Q. PLEASE DESCRIBE THE REASONING FOR REQUESTING
APPROVAL OF THE DRY LAKE EAST, BOULDER SOLAR III,
LIBRA SOLAR & STORAGE, AND CORSAC GENERATING
STATION 2 POWER PURCHASE AGREEMENTS AT THIS TIME.

A. The Companies seek approval of the PPAs with the intent of growing its portfolio of renewable energy resources to meet several energy, capacity, and policy objectives including: 1) demonstrated ability to interconnect and achieve COD by 2029, 2) comply with the Nevada RPS mandate, 3) support reducing the Companies' open capacity positions, 4) meet customers' sustainability goals for renewable energy, including providing innovative new Energy Supply Agreements ("ESAs") filed under the pending Clean Transition Tariff ("CTT"), 5) provide supplemental reliability benefits to the Companies' system, and 6) satisfy State of Nevada clean energy policy goals and progressing towards the state goal of matching electricity sales with zero carbon generation by 2050.

12. Q. PLEASE DESCRIBE THE COMPANIES' APPROACH TO
RENEWABLES AND STORAGE REQUESTS FOR PROPOSALS
("RFP") AND ENERGY SUPPLY CONTRACTS.

A. The Companies will continue to utilize various types of RFPs and other procurement paths, such as Open Resource RFP, self-development, and bilateral negotiations, to meet the resource needs of customers. Those needs are driven by, among other things, resource adequacy, compliance requirements, customer renewable energy program fulfillment, and specific customer demand. The Companies' Open Resource RFPs will be agnostic to generation and energy storage technologies and contractual structures to identify the best projects to meet both customer and system needs. Although there have been some cancelations and

delays for the approved pipeline PPAs, performing a holistic evaluation of all technologies and contractual structures will help the Companies understand and adapt to the evolving market conditions and select the best value project(s) for the Companies' customers. The results of these RFPs will continue to be utilized to support the Companies' long-term resource planning processes and will be shared in subsequent regulatory filings.

While RFPs have been and will continue to play an important role in fulfilling resource needs, it is important that the Companies also pursue a broader approach to acquiring new resources that strikes a balance between third party and company-ownership of resources and includes all procurement paths, including bilateral and self-development. Project price, performance, and schedule will be key inputs to the analysis of future resource plans regardless of the resource procurement strategy and can be aligned with the overall long-term planning processes.

13. Q. GIVEN THAT THE ONLY RENEWABLE PROJECTS BROUGHT FORWARD FOR APPROVAL ARE PPAS, WHY ARE THE COMPANIES NOT PROPOSING ANY COMPANY-OWNED RENEWABLE PROJECTS IN THIS FILING?

A. In the Companies' most recent IRP filing, the Companies brought forward the Company-owned Sierra Solar project. Although approved, the Commission's Order added further conditions including a price cap and various liquidated damages provisions.² At this time, the Companies are continuing to evaluate the impact of the Commission's Order for the Sierra Solar project on future Company-owned renewables projects. While no Company-owned renewable projects are proposed

² Docket No. 23-08015, Apr. 9, 2024, Modified Order.

1 in this filing, the Companies do anticipate submitting Company-owned renewables
2 projects in future IRPs.
3

4 **14. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?**

5 A. Yes.
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27

EXHIBIT DAGLIAN-DIRECT-1

STATEMENT OF QUALIFICATIONS

Jimmy Daghlion
7155 Lindell Rd Las Vegas, NV 89146
Jimmy.Daghlian@nvenergy.com | (702) 402-6750

PROFESSIONAL EXPERIENCE

NV Energy, Las Vegas, NV

Vice President, Renewables, December 2022 - Current

- Oversee the origination and development of Companies' Renewables resource to meet capacity requirement, Renewable Portfolio Standards requirements, and address resource adequacy. Manage contract management department for pre-commercial and post-commercial execution of Purchase Power Agreements.

Director, Delivery Operations South, July 2021 - December 2022

- Directed Las Vegas Lines operations for the construction and maintenance of overhead and underground distribution and transmission circuits.

Director, Generation Support, December 2017 - July 2021

- Directed technical, operational, and economic analyses to support energy supply generating resources and related processes.

Manager, Plant Engineering and Technical Services, August 2013 - December 2017

- Managed corporate engineering services for Companies' generating stations. Supported the reliability improvement plans, managed inspection and repair standards, resolved fleet issues and developed programs for long term reliable and safe operations of generating assets.

Engineering Staff, January 2012 - August 2013

- Provided engineering, and project management support of power generation's mechanical system. Completed reliability inspections, equipment testing and outage restoration support for all the Companies' generating stations.

TAQA Energy, El Jadida, Morocco

Technical Advisor, May 2010-January 2012

- Supervised and managed major retrofits projects, inspection/maintenance programs and upgrades to improve plant performance at a large ~1300 MW coal fired plant.

Clyde Bergemann/Anthony Ross, Portland, OR

Business Development Manager, November 2008 - May 2010

- Provided guidance and leadership in the development of coal combustion systems, equipment, parts, and services for the reduction of Nitrogen Dioxide emissions.

PacifiCorp Energy, Salt Lake City, UT

Lead/Senior Engineer, June 2004 - November 2008

- Developed corporate-wide asset management combustion maintenance and operational plan best practices for equipment, fuels, and combustion related issues to increase fleet availability and decrease unplanned outages.

Alstom Power, Salt Lake City, UT

Lead/Senior Engineer, December 2001 - June 2004

- Provided project management guidance and support on several large-scale Low Nitrogen Dioxide and burner installation and retrofit projects for various utilities in the western United States.

EDUCATION

Westminster College, Salt Lake City, UT

Master of Business Administration, December 2006

University of Utah, Salt Lake City, UT

Master of Science in Chemical and Fuels Engineering, December 2001

University of Utah, Salt Lake City, UT

Bachelor of Science in Chemical Engineering, May 1999

AFFIRMATION

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

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

Date: May 31, 2024


JIMMY DAGHLIAN

SEAN SPITZER

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

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

Prepared Direct Testimony of

Sean Spitzer

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

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

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

A. I graduated from California State University, Chico, with a Masters in Environmental Science in 2011 and a Bachelor of Science in Environmental Studies from University of Santa Barbara, California, in 2006. Before joining the Companies, I worked for General Electric (GE Hitachi Nuclear Energy), and Clean Harbors Environmental Services. In my current role, I serve as a Senior Project Manager for Renewable Energy and Origination. My responsibilities include the procurement and contract negotiations for renewable and non-renewable energy resources.

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

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

A. In my current position, I collaborate with a team of planners, engineers, analysts, and managers that manage all aspects of origination of energy and capacity procurement for the Companies.

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

A. No.

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

A. The purpose of my testimony is to sponsor the Companies’ Renewables Section of the Supply Plan to the 2024 Joint Triennial Integrated Resource Plan (“2024 Joint IRP”). Specifically, I explain and support the Companies’ plan for complying with Nevada’s renewable portfolio standard (“RPS”), and I also present four Long-Term Power Purchase Agreements for approval. Additionally, I provide an update on the Valmy geothermal resources.

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

A. I am sponsoring the following Exhibit:

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

I am sponsoring the following Technical Appendices:

- REN-1 Proposed Projects 12x24 Supply Tables
- REN-2 Renewable Portfolio Standard Buildout Scenarios
- REN-3-DLE(a) Long-term Power Purchase Agreement with Dry Lake East Energy Center, LLC (Redacted)
- REN-3-DLE(b) Dry Lake East Solar and BESS Due Diligence Summary (Confidential)
- REN-3-DLE(c) Dry Lake East NAC Compliance
- REN-3-DLE(d) Dry Lake East PPA Key Provisions
- REN-4-BS3(a) Long-term Power Purchase Agreement with Boulder Solar III, LLC (Redacted)
- REN-4-BS3(b) Boulder Solar III Solar and BESS Due Diligence Summary (Confidential)
- REN-4-BS3(c) Boulder Solar III NAC Compliance
- REN-4-BS3(d) Boulder Solar III PPA Key Provisions
- REN-5-LS(a) Long-term Power Purchase Agreement with Libra Solar, LLC (Redacted)
- REN-5-LS(b) Libra Solar & Storage Solar and BESS Due Diligence Summary (Confidential)
- REN-5-LS(c) Libra Solar & Storage Solar NAC Compliance
- REN-5-LS(d) Libra Solar PPA Key Provisions
- REN-6-CS2(a) Long-term Power Purchase Agreement with Corsac Generating Station 2, LLC (Redacted)
- REN-6-CS2(b) Corsac Generating Station 2 Geothermal Due Diligence Summary (Confidential)
- REN-6-CS2(c) Corsac Generating Station 2 NAC Compliance

- REN-6-CS2(d) Corsac Generating Station 2 PPA Key Provisions
- REN-7 Cost Comparison of Solar plus Storage RFP bids to PPA pricing
- REN-8 2023 OR RFP Bid Score Summary (Confidential)

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

A. Yes. Technical Appendices REN-3-DLE(b), REN-4-BS3(b), REN-5-LS(b), REN-6-CS2(b) and REN-8 are confidential as they contain the Companies' due diligence and pricing related reviews of the projects which, if publicly disclosed, could provide an unfair market advantage to competitors by showing the Companies' internal analysis and pricing of projects. Confidentiality of the Companies' technical evaluation of projects is essential to future successful negotiations and competitive solicitations to obtain the best value on behalf of the Companies' customers. REN-8 provides the results of the Companies' scoring of the 2023 Requests for Proposals ("RFP") bids received. Disclosure of confidential cost and bid information contained in Technical Appendix REN-8 could negatively impact the Companies' ability to obtain competitive offers from bidders in the future and deliver the best value to the Companies' customers.

Additionally, Technical Appendices REN-3-DLE(a), REN-4-BS3(a), REN-5-LS(a) and REN-6-CS2(a) are redacted. These PPAs contain an Approved Vendors List exhibit which has been redacted from the publicly filed versions. The exhibits contain commercially sensitive information disclosure of which may negatively affect the Companies and their contractual counterparties.

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

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

9. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF THE
COMMISSION'S REGULATORY OPERATIONS STAFF ("STAFF") OR
THE NEVADA ATTORNEY GENERAL'S BUREAU OF CONSUMER
PROTECTION ("BCP") TO FULLY INVESTIGATE THE INFORMATION
SET FORTH IN THIS FILING?

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

10. Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. In section II, I discuss the Companies' plans to comply with Nevada's RPS. In
sections III, IV, V, VI, and VII, I discuss the Companies' requests for approval of
the Dry Lake East, Boulder Solar III, Libra Solar and Storage, and Corsac
Generating Station 2 Geothermal Power Purchase Agreements ("PPAs") while
discussing the Companies' recent RFP results. Specifically, I address:

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

Finally, in section VIII, I discuss the Valmy geothermal resources update.

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

11. Q. PLEASE DESCRIBE NEVADA'S RPS.

1 A. Nevada utilizes a portfolio energy credit (“PC”) system to measure RPS
2 compliance. Eligible PCs can come from multiple sources. The most common
3 sources of PCs are from renewable generation owned by the Companies or under
4 PPAs, non-current year renewable generation banked PCs, eligible station usage
5 PCs, grandfathered solar multiplier PCs, and finally PCs derived from energy
6 efficiency and demand response programs.

7
8 Nevada’s RPS requirement for calendar year 2024 is set at 34 percent of retail
9 sales.¹ This means that Nevada Power and Sierra must have PCs equal to or greater
10 than 34 percent of their respective retail sales. The RPS will increase to 42 percent
11 in 2027, and 50 percent in 2030, and remain at 50 percent each calendar year
12 thereafter.²

13
14 The state also has an aspirational goal for energy production from net-zero carbon
15 dioxide emission resources equal to the total amount of electricity sales by 2050.³
16

17 **12. Q. PLEASE DESCRIBE THE RPS RENEWABLE PLAN DEVELOPED FOR**
18 **THE IRP.**

19 A. The Companies use a model to forecast future PC requirements and supplies. The
20 purpose of the model is to determine whether the Companies will have sufficient
21 PCs to meet their RPS obligations. If, outside the IRP three-year action plan period,
22 the model indicates that the PC supply is insufficient to meet the RPS, generic
23 placeholder projects are added, as needed, to fill the credit gaps. Placeholders have
24 also been added to illustrate the timing and capacity required if the Companies are
25

26 ¹ Nevada Revised Statutes (“NRS”) § 704.7821.

27 ² *Id.*

³ *See* NRS § 704.7820.

to achieve their goal of meeting one hundred percent of their retail load with renewable resources by 2050.

Please refer to the narrative for a description of key inputs and assumptions to the model.

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

A. The renewable expansion plan developed for short-term planning purposes captures actual historical generation trends based on two or more years of operating data. After coordinating with internal contract administrators, the Companies adjusted the supply table based on this historical trend to reflect the most recent operating data to account for potential short-term anomalies. Historical output trends for Sierra contracted renewable projects resulted in an adjustment to 10 projects, seven decreases and three increases. In total, these adjustments lowered the amount of renewable energy by an average of 2.99 percent over the 2025-2027 action plan period.

The same approach for Nevada Power resulted in adjustments to the amount of renewable energy for 13 projects, 12 decreases and one increase. In total, these adjustments lowered the amount of renewable and derived PC by an average of 2.67 percent over the 2025-2027 action plan period. The Companies believe that this approach maximizes the reliability and accuracy for the overall energy supply used in short-term planning.

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

A. Nevada Power exceeded the 2023 RPS requirement of 29 percent based on the Companies' 2023 results reported in April 2024. However, Nevada Power's RPS compliance outlook is cautious. The limited available land for development, multiyear project permitting timelines, and lack of available transmission capacity are key constraints in the renewable project pipeline. The completion of costly requisite network upgrades, procurement of long-lead critical equipment such as breakers and transformers, as well as project permit issuance and transmission interconnectivity capability, are interdependent project milestones that are subject to various independent external forces that cannot be easily mitigated even with diligent planning. Nevada's renewable project pipeline, therefore, carries some amount of inherent risk, as most recently demonstrated by the termination of the Boulder Solar III PPA previously approved in Docket No. 20-07023. To this end, Nevada Power will continue to explore all options, including continuing to issue renewable energy RFPs, self-developing projects, conducting bilateral asset purchase and other commercial transactions and exploring short-term purchase agreements that benefit customers, so that it can procure the renewable generating and storage resources needed to continue its commitment to becoming carbon-free. Nevada Power's challenge is to make certain that it has sufficient renewable resources, existing and pipeline, to satisfy all credit and energy needs for at least five years. A five-year time frame provides the cushion needed to methodically seek, submit for approval, and construct new renewable resources. In summary, with the approval of the proposed projects in the 2024 IRP Filing, Nevada Power should be positioned to meet all of its future credit commitments (RPS, NV

GreenEnergy Rider (“NGR”), and energy supply agreements (“ESA”)) for the next five years.⁴

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

A. Sierra exceeded the 2023 RPS requirement of 29 percent based on the Companies’ 2023 results reported in April 2024. However, Sierra’s RPS compliance outlook is uncertain. This is different from 2023’s outlook of positive for several reasons. First, and primarily, it is the projected load growth. Sierra’s current retail load outlook is significantly higher than that of the previous approved plan. Under the current load forecast, while Nevada Power’s retail sales are projected to increase slightly, Sierra’s retail sales are projected to increase significantly. Because the RPS credit requirement is tied directly to retail sales, this dramatically increased Sierra’s forecasted RPS credit requirement.

The second reason Sierra’s compliance is uncertain is cancelled projects by developers.⁵ While Nevada Power was hit by the same wave of canceled projects, it did not face the same degree of projected sales growth. While every project is entered into with the expectation of success, events can and do happen that make once-viable projects unviable. The primary driver for the latest wave of cancellations was cost. Most of the canceled projects were negotiated pre-COVID, and the supply disruptions and related increases in component and labor costs made the projects too costly to move forward.

⁴ Please refer to the Renewable Energy Planning section in the Company’s 2024 Joint IRP filing for additional details

⁵ Please refer to the Renewable Energy Informational Updates section in the Company’s 2024 Joint IRP filing for additional details on the Valmy Eavor project

A third contributing factor to Sierra’s uncertain RPS compliance outlook is transmission constraints. Currently, there is limited ability to move energy to load in Sierra’s service territory in the near term, requiring completion of contingent facilities and significant additional transmission infrastructure to remedy. The completion of Greenlink West and Greenlink North will allow for a significant addition of renewable energy capacity in Sierra’s territory when it goes into service. It is the combination of these three forces that changed Sierra’s outlook from positive to uncertain.⁶ In summary, with the approval of the proposed projects in the 2024 IRP filing, and the sharing of the PCs between Nevada Power and Sierra, the Companies are projected to remain compliant throughout the action period, 2025-2027, and remain compliant through 2034 – the end of the period evaluated.

III. PPAs REQUESTED FOR APPROVAL

16. Q. TO WHAT EXTENT WOULD THE APPROVAL OF THE DRY LAKE EAST, BOULDER SOLAR III, LIBRA SOLAR, AND CORSAC GENERATING STATION 2 PPAs BENEFIT THE COMPANIES’ RPS COMPLIANCE OUTLOOK?

A. The approval of the Dry Lake East, Boulder Solar III, and Libra Solar PPAs adds renewable capacity,⁷ and is needed to position the Companies to comply with the RPS.

The added capacity is ever more critical due to the cancelations, delays, or shortfalls of previously approved projects. While the Companies’ will seek to extend the term of existing geothermal PPAs, reaching commercial agreements with the counterparties to extend the terms is not guaranteed; therefore, these renewable

⁶ Please refer to the Renewable Energy Planning section in the Company’s joint 2024 IRA filing for additional details

⁷ A portion of the power and PCs from the paired solar and BESS projects are part of ESAs for existing customers applying through the pending Clean Transition Tariff (“CTT”), as described in the direct testimony of Janet Wells.

PPAs will also help replace the energy lost as several long-term geothermal PPAs are set to expire in the near term. Finally, it would be a significant step in helping the Companies get closer to its goal of providing 100 percent carbon-free energy to its customers by 2050 while meeting customers' renewable energy needs.

Regarding Corsac Generating Station 2, while 100 percent of the energy and PCs will be assigned to Callisto Enterprises LLC ("Callisto") through an ESA, the energy that Callisto receives from the generating facility will reduce the Companies' load obligation to an otherwise fully bundled customer, and similarly, reduce the Companies' overall RPS obligation.

17. Q. WERE ANY OF THE PPAs BID IN A RENEWABLE ENERGY RFP?

A. Yes, the Dry Lake East, Boulder Solar III, and Libra Solar & BESS PPAs were bid into the Companies' 2023 open resource RFP. As a result, the Companies entered into PPA negotiations with each of the counterparties starting in December 2023. The Corsac Generating Station 2 Geothermal PPA was not bid into any of the Companies' RFPs, but rather was the result of discussions between the Companies, Callisto—a customer seeking an ESA through the CTT, and Fervo Energy—the parent company of Corsac Generating Station 2.

18. Q. PLEASE COMMENT ON THE EVALUATION AND NEGOTIATIONS TIMELINE FOR DRY LAKE EAST, BOULDER SOLAR III, LIBRA SOLAR & STORAGE, AND CORSAC GENERATING STATION 2 PPAS.

A. The Companies completed technical and pricing due diligence of the Dry Lake East, Boulder Solar III, and Libra Solar & Storage proposals. The due diligence

included: (1) status and timing of interconnection, (2) evaluation of site control, (3) status of material permits, (4) review of material equipment for bankability and performance, (5) determination of whether the project development milestone schedule supports contractual commercial operation date, (6) evaluation of development and operating experience of the developer, (7) evaluation of the developer's financial capability, (8) evaluation of developer's jobsite safety performance history, (9) evaluation of the available water supply, and (10) levelized cost of energy price evaluation. For Corsac Generating Station 2, pricing evaluation was not considered because the PPA is part of a sleeved ESA agreement with Callisto that was negotiated outside of the RFP process; however the Companies followed the same process utilized in the RFP for technical due diligence and additionally developed contractual provisions that hold remaining ratepayers harmless from this transaction. Based on the analyses for all PPAs, no material concerns were raised. The due diligence summaries for Dry Lake East, Boulder Solar III, Libra Solar & Storage, and Corsac Generating Station 2 are included as Confidential Technical Appendices REN-3-DLE(b), REN-4-BS3(b), REN-5-LS(b), and REN-6-CS2(b), respectively.

19. Q. PLEASE DESCRIBE ANY ADDITIONAL ANALYSIS CONDUCTED FOR THE PPAs.

A. The Companies' Resource Planning group conducted a present worth revenue requirement ("PWRR") analysis of Dry Lake East, Boulder Solar III, and Libra Solar & Storage PPAs. The PWRR analysis is described in the Economic Analysis section of the narrative.

20. Q. WHY ARE ADDITIONAL RFP AND BILATERAL PROJECTS THAT WERE EVALUATED NOT BEING PROPOSED FOR APPROVAL?

A. The Companies' evaluation of the additional projects, including, but not limited to, due diligence and commercial negotiations, could not be completed in time to bring any of these projects forward in this filing but remain candidates for future filings. However, these and other available projects will continue to be evaluated as part of subsequent open resource RFPs and bilateral discussions.

IV. DRY LAKE EAST PPA

21. Q. PLEASE DESCRIBE THE DRY LAKE EAST PPA.

A. Nevada Power and Dry Lake East Energy Center, LLC, executed the Dry Lake East PPA with an effective date of January 31, 2024. The PPA is for 200 MW of capacity generated by a 200 MW solar PV facility paired with a 200 MW lithium-ion battery with 4-hour duration, or 800 megawatt-hours ("MWh"). The Dry Lake East facility will be located approximately 20 miles northeast of Las Vegas in Clark County, on Bureau of Land Management land. The project is expected to produce 577,194 MWh of renewable energy and associated PCs annually. The PPA term will start on the commercial operation date ("COD"), December 01, 2026, and end on December 31, 2051. The PPA includes options for Nevada Power to purchase the asset at periodic intervals after commercial operation and at the end of the term. The fixed PPA price is \$36.78 per MWh for the 25-year solar term, and the storage rate of the battery is \$13,440 per month for the 20-year BESS term. This price is flat for the term of the contract and includes all costs associated with both the generating plant and renewable energy attributes. The PPA is provided as Technical Appendix REN-3-DLE(a).

22. Q. **WHAT KEY PROVISIONS HAVE THE COMPANIES NEGOTIATED IN THE DRY LAKE EAST PPA?**

A. Technical Appendix REN-3-DLE(d) provides a table detailing the key provisions of the Dry Lake East PPA.

23. Q. **WHAT ARE THE BENEFITS THE DRY LAKE EAST PPA BRINGS TO NEVADA POWER, ITS CUSTOMERS, AND THE STATE?**

A. With an expected COD of December 1, 2026, the Dry Lake East solar and storage facility will achieve COD the earliest among the solar and storage PPAs being proposed in this filing. Dry Lake East will help to reduce Nevada Power's open capacity position, and the BESS is capable of providing night-time renewable energy in support of the RPS and zero-carbon goals. In addition to the energy and capacity, customers will benefit from all associated environmental and renewable energy attributes as Dry Lake East will help displace fossil-fueled generation. Further, the Nevada economy will benefit from the approval of this project. Technical Appendix REN-3-DLE(c) sets forth a complete listing of the economic and environmental benefits of the Dry Lake East project, as required by the Commission's regulations.⁸

24. Q. **IS THE PPA PRICE FOR DRY LAKE EAST COMPETITIVE?**

A. Yes. The Companies calculated the hybridized levelized cost of energy ("LCOE") for Dry Lake East that considers several key inputs including the price of solar, battery, and \$2.0 million of network upgrade costs associated with the project. Dry Lake East's LCOE of \$101.41 per MWh is below the average LCOE of \$102.76 of the comparable 1:1 solar plus storage PPA bids received in the Companies' 2023 OR RFP, as shown in Technical Appendix REN-7. Of the five solar and storage

⁸ See Nevada Administrative Code § 704.8887(2).

shortlisted PPAs proposals from the 2023 OR RFP, Dry Lake East ranked third in terms of LCOE cost-competitiveness.

25. Q. PLEASE SUMMARIZE THE COMPANIES' REQUEST TO APPROVE THE DRY LAKE EAST PPA.

A. The Companies request that the Commission approve the Dry Lake East PPA for 200 MW of new generation between Nevada Power and Dry Lake East Energy Center, LLC. This project will help support native load customer needs and RPS compliance at competitive pricing for a solar plus storage resource.

V. BOULDER SOLAR III

26. Q. PLEASE DESCRIBE THE BOULDER SOLAR III PPA.

A. Nevada Power and Boulder Solar III, LLC, executed the Boulder Solar III PPA with an effective date of May 3, 2024. The PPA is for 127.9 MW of capacity generated by a 127.9 MW solar PV facility paired with a 127.9 MW lithium-ion battery with 4-hour duration, or 511 MWh. The Boulder Solar III facility will be located near Boulder City in El Dorado Valley, Clark County. The project is expected to produce 471,461 MWh of renewable energy and associated PCs annually. The PPA term will start on the COD, June 1, 2027, and end on December 31, 2052. The PPA includes options for Nevada Power to purchase the asset at periodic intervals after commercial operation and at the end of the term. The fixed PPA price is \$34.60 per MWh for the 25-year solar term. This price is flat for the term of the contract and includes all costs associated with both the generating plant and renewable energy attributes. The storage rate of the battery is \$15,460 per MW-month for the first 20-years of the BESS term, and \$0 per MW-month for the BESS

during years 21-25 of the term. The PPA is provided as Technical Appendix REN-4-BS3(a).

27. Q. WHAT KEY PROVISIONS HAVE THE COMPANIES NEGOTIATED IN THE BOULDER SOLAR III PPA?

A. Technical Appendix REN-4-BS3(d) provides a table detailing the key provisions of the Boulder Solar III PPA.

28. Q. WHAT ARE THE BENEFITS THE BOULDER SOLAR III PPA BRINGS TO NEVADA POWER, ITS CUSTOMERS, AND THE STATE?

A. With an expected COD of June 1, 2027, the Boulder Solar III solar and storage facility will achieve COD the second-earliest among the solar and storage PPAs being proposed in this filing. Boulder Solar III will help to reduce Nevada Power's open capacity position, and the BESS is capable of providing night-time renewable energy in support of the RPS and zero-carbon goals. In addition to the energy and capacity, customers will benefit from all associated environmental and renewable energy attributes as Boulder Solar III will help displace fossil-fueled generation. Further, the Nevada economy will benefit from the approval of this project. Technical Appendix REN-4-BS3(c) sets forth a complete listing of the economic and environmental benefits of the Boulder Solar III project, as required by the Commission's regulations.⁹

29. Q. IS THE PPA PRICE FOR BOULDER SOLAR III COMPETITIVE?

A. Yes. The Companies calculated the hybridized LCOE for Boulder Solar III that considers several key inputs including the price of solar, battery, and \$0 of network upgrade costs of the project. Boulder Solar III's LCOE of \$84.64 per MWh is below

⁹ Nevada Administrative Code § 704.8887(2).

the average LCOE of \$102.76 of the comparable 1:1 solar plus storage PPA bids received in the Companies' 2023 OR RFP, as shown in Technical Appendix REN-7. Of the five solar and storage shortlisted proposals from the 2023 OR RFP, Boulder Solar III ranked first in terms of LCOE cost-competitiveness.

30. Q. PLEASE SUMMARIZE THE COMPANIES' REQUEST TO APPROVE THE BOULDER SOLAR III PPA.

A. The Companies request that the Commission approve the Boulder Solar III PPA for 127.9 MW of new generation between Nevada Power and Boulder Solar III, LLC. This project will help support native load customer needs and RPS compliance at competitive pricing for a solar plus storage resource.

VI. LIBRA SOLAR & STORAGE PPA

31. Q. PLEASE DESCRIBE THE LIBRA SOLAR & STORAGE PPA.

A. Nevada Power and Libra Solar, LLC, executed the Libra Solar & Storage PPA with an effective date of May 3, 2024. The PPA is for 700 MW of capacity generated by a 700 MW solar PV facility paired with a 700 MW lithium-ion battery with 4-hour duration, or 2,800 MWh. The Libra Solar & Storage facility will be located approximately 20 miles south of the Fort Churchill Substation in Mineral County, Nevada. The project is expected to produce 1,948,197 MWh of renewable energy and 1,798,716 of associated PCs annually. The PPA term will start on the COD, December 01, 2027, and end on December 31, 2052. The PPA includes options for the Companies to purchase the asset at periodic intervals after commercial operation and at the end of the term. The fixed PPA price is \$34.97 per MWh for the 25-year solar term. This price is flat for the term of the contract and includes all costs associated with both the generating plant and renewable energy attributes.

The storage rate of the battery is \$13,350 per month for the first 20-years of the BESS term at the full 700 MW capacity, and in years 21-25 of the term the BESS capacity rating is reduced to 500 MW and the BESS pricing is reduced to \$0.00/MW-month. The PPA is provided as Technical Appendix REN-5-LS(a).

32. Q. WHAT KEY PROVISIONS HAVE THE COMPANIES NEGOTIATED IN THE LIBRA SOLAR & STORAGE PPA?

A. Technical Appendix REN-5-LS(d) provides a table detailing the key provisions of the Libra Solar & Storage PPA.

33. Q. WHAT ARE THE BENEFITS THE LIBRA SOLAR & STORAGE PPA BRINGS TO NEVADA POWER, ITS CUSTOMERS, AND THE STATE?

A. With an expected commercial operation date of December 1, 2027, the Libra Solar & Storage solar and storage facility will achieve COD the third-earliest among the solar and storage PPAs being proposed in this filing. Libra Solar & Storage will help to reduce Nevada Power's open capacity position, and the BESS is capable of providing night-time renewable energy in support of the RPS and zero-carbon goals. In addition to the energy and capacity, customers will benefit from all associated environmental and renewable energy attributes as Libra Solar & Storage will help displace fossil-fueled generation. Further, the Nevada economy will benefit from the approval of this project. Technical Appendix REN-5-LS(c) sets forth a complete listing of the economic and environmental benefits of the Libra Solar & Storage project, as required by the Commission's regulations.¹⁰

¹⁰ See Nevada Administrative Code § 704.8887(2).

1 **34. Q. IS THE PPA PRICE FOR LIBRA SOLAR & STORAGE COMPETITIVE?**

2 A. Yes. The Companies calculated the LCOE for Libra Solar & Storage that considers
3 several key inputs including the price of solar, battery, and \$3.9 million of network
4 upgrade costs of the project. Libra Solar & Storage's LCOE of \$93.69 per MWh is
5 below the average LCOE of \$102.76 of the comparable 1:1 solar plus storage PPA
6 bids received in the Companies' 2023 OR RFP, as shown in Technical Appendix
7 REN-7. Of the five solar and storage shortlisted proposals from the 2023 OR RFP,
8 Libra Solar & Storage ranked second in terms of LCOE cost-competitiveness.
9

10 **35. Q. PLEASE SUMMARIZE THE COMPANIES' REQUEST TO APPROVE**
11 **THE LIBRA SOLAR & STORAGE PPA.**

12 A. The Companies request that the Commission approve the Libra Solar & Storage
13 PPA for 700 MW of new generation between Nevada Power and Libra Solar, LLC.
14 This project will help support native load customer needs and RPS compliance at
15 competitive pricing for a solar plus storage resource.
16

17 **VII. CORSAC GENERATION STATION 2 PPA**

18 **36. Q. PLEASE DESCRIBE THE CORSAC GENERATION STATION 2 PPA.**

19 A. Sierra and Corsac Generating Station 2, LLC, executed the Corsac Generating
20 Station 2 PPA with an effective date of May 3, 2024. The Corsac Generating Station
21 2 PPA was executed with the intent of fulfilling a sleeved ESA with Callisto. The
22 Companies expect to file the ESA for the Commission's consideration in a separate
23 docket at the same time as this IRP filing. Under the terms of the ESA, 100 percent
24 of the energy and PCs from Corsac Generating Station 2 will be provided to
25 Callisto.
26
27

The Corsac Generating Station 2 PPA is for 115 MW of capacity generated by a 24/7 renewable energy geothermal resource. The Corsac Generating Station 2 facility will be located outside the city of Fallon in Churchill County, Nevada. The project is expected to produce 872,140 MWh of renewable energy, and 910,804 MWh of associated PCs inclusive of station usage, annually. The PPA term will start on the COD, January 30, 2030, and end on December 31, 2045. The PPA does not include options for Sierra to purchase the asset at any time during or after the term. The fixed PPA price is \$107 per MWh for the 15-year term. This price is flat for the term of the contract and includes all costs associated with both the generating plant and renewable energy attributes. The PPA is provided as Technical Appendix REN-6-CS2(a).

37. Q. HOW IS THE CORSAC GENERATION STATION 2 PROJECT'S GEOTHERMAL TECHNOLOGY DIFFERENT FROM CONVENTIONAL GEOTHERMAL?

A. The project's geothermal wells will utilize a proprietary and innovative drilling technology developed by Fervo Energy ("Fervo"). Fervo, the parent company of Corsac Generating Station 2, is a next-generation geothermal developer founded in 2017 and is currently developing several geothermal projects in Nevada and Utah. Fervo's drilling approach entails drilling horizontal directions at depth to maximize reservoir volume and surface area. The technique enables energy capture from many more permeable zones than is generally possible in conventional vertical geothermal wells.

38. Q. IS THE CORSAC GENERATION STATION 2 PPA CONTINGENT UPON APPROVAL OF THE ESA WITH CALLISTO?

1 A. Yes. In addition to the requisite approval from the Commission, the PPA is not
2 effective until all conditions to the effectiveness of the ESA between Sierra and
3 Callisto have been satisfied.

4
5 **39. Q. GIVEN THE CORSAC GENERATING STATION 2 PPA IS A SLEEVED**
6 **AGREEMENT FOR AN ESA, WHAT CUSTOMER PROTECTIONS HAS**
7 **SIERRA NEGOTIATED IN THE PPA?**

8 A. The Corsac Generating Station 2 PPA includes several customer protections
9 consistent with the Companies' other PPAs through various provisions such as
10 Sierra's ability to collect damages due to termination or production shortfalls.

11
12 **40. Q. WHAT KEY PROVISIONS HAVE THE COMPANIES NEGOTIATED**
13 **WITH CORSAC GENERATING STATION 2 LLC?**

14 A. Technical Appendix REN-6-CS2(d) provides a table detailing the key provisions
15 of the Corsac Generating Station 2 PPA.

16
17 **41. Q. WHAT ARE THE BENEFITS THE CORSAC GENERATION STATION**
18 **2 PPA BRINGS TO SIERRA, ITS CUSTOMERS, AND THE STATE?**

19 A. The Corsac Generating Station 2 PPA provides for an innovative new energy
20 supply, fulfilling an ESA with Callisto to meet its load and deliver clean energy and
21 renewable energy credits around-the-clock. The PPA supports the quickly evolving
22 demands of Callisto, while providing economic and environmental benefits to all
23 customers. By serving customer load with renewable energy, all customers will
24 benefit from associated environmental and renewable energy attributes as Corsac
25 Generating Station 2 will help displace fossil-fueled generation. Further, the
26 Nevada economy will benefit from the approval of this project. Technical Appendix

REN-6-CS2(c) sets forth a complete listing of the economic and environmental benefits of the Corsac Generating Station 2 project, as required by the Commission's regulations.¹¹

42. Q. IS THE PPA PRICE FOR CORSAC GENERATION STATION 2 COMPETITIVE?

A. Yes. The Companies calculated the LCOE for Corsac Generating Station 2 that considers several key inputs including the price of generation and \$2 million of network upgrade costs of the project. Corsac Generating Station 2's LCOE is \$107.69 per MWh. However, because the PPA is part of a sleeved ESA agreement with Callisto, pricing was not a deciding factor in the bilateral negotiations.

43. Q. PLEASE SUMMARIZE THE COMPANIES' REQUEST TO APPROVE THE CORSAC GENERATION STATION 2 PPA.

B. The Companies request that the Commission approve the Corsac Generating Station 2 PPA for 115 MW of new generation between Sierra and Corsac Generating Station 2, LLC. This project will help support Callisto's load and customer needs while providing environmental benefits to other customers and the state.

44. Q. PLEASE SUMMARIZE THE COMPANIES' REQUESTS FOR APPROVAL IN THIS IRP.

A. The Companies propose that the Commission approve the four renewable energy power purchase agreements:

¹¹ See Nevada Administrative Code § 704.8887(2).

- 1) Approval for the PPA with the Dry Lake East 200 MW solar PV with 200 MW BESS facility, with a finding that the energy price of \$36.78/MWh and storage price of \$13,440/MW-month is just and reasonable;
- 2) Approval for the PPA with the Boulder Solar III 127.9 MW solar PV with 127.9 MW BESS facility, with a finding that the energy price of \$34.60/MWh and storage price of \$15,460/MW-month is just and reasonable,
- 3) Approval for the PPA with the Libra Solar & Storage 700 MW solar PV with 700 MW BESS facility, with a finding that the energy price of \$34.97/MWh and storage price of \$13,350/MW-month is just and reasonable,
- 4) Approval for the PPA with the Corsac Generating Station 2 115 MW geothermal facility, with a finding that the energy price of \$107/MWh is just and reasonable per the sleeved ESA with Callisto.

VIII. VALMY GEOTHERMAL RESOURCES UPDATE

45. Q. PLEASE PROVIDE AN UPDATE REGARDING GEOTHERMAL RESOURCES AND DEVELOPMENT IN THE VALMY REGION.

A. In addition to the discussion of the North Valmy Eavor PPA as described in Mark Warden's testimony, the Companies are providing the following update on geothermal resources and development in the Valmy region in satisfaction of compliance Directive 5 of the Order in Docket No. 23-08015.

In the Companies' 2023 OR RFP, only one geothermal bid was received. The proposal included a collection of geothermal project sites, two of which were located near the Valmy region. However, the Companies calculated the LCOE of

1 this proposal and determined that it was more than 100 percent higher than the
2 calculated LCOE of the Companies' most recent geothermal portfolio approved in
3 Docket No. 22-11032. As discussed in the Economic Analysis section of the
4 narrative, the economic results of geothermal comparison for individual project
5 screening showed that this geothermal proposal option resulted in more than \$200
6 million additional cost compared to the Base Case. Furthermore, the PLEXOS LT
7 model for geothermal did not select any geothermal resources until 2045, as also
8 discussed in the Economic Analysis Section of the Supply Plan. The cost of
9 geothermal resources considered in this filing were not competitive to other sources
10 of renewable energy.

11
12 More generally, the long development periods for greenfield geothermal resources
13 can add significant schedule risk. The Companies' experience with geothermal
14 developers has shown that, even for a successful site to go from exploration to
15 commercial operation can take 7 to 10 years. Over time, as more of Nevada's prime
16 geothermal potential sites are developed, the availability of high value geothermal
17 sites suitable for development is diminished. The Companies cannot speculate on
18 the underlying factors that geothermal developers use to determine their pricing
19 proposals, but will continue to work with the pool of geothermal developers
20 actively bidding Nevada geothermal projects for the Companies' consideration to
21 achieve the most cost-competitive outcome.

22
23 As of the date of this filing, the Companies have not received any viable proposals
24 for geothermal resources in the Valmy region for evaluation. The Companies will
25 pursue any bilateral opportunities as well as continue to solicit RFPs for renewable
26
27

energy including geothermal resources in areas, including, but not limited to, the
Valmy region.

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

A. Yes

EXHIBIT SPITZER-DIRECT-1

STATEMENT OF QUALIFICATIONS

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

Professional with over 13 years of experience in the power industry. Emphasis on environmental regulatory compliance for electric utilities, with recent focus on renewable energy origination activities.

EXPERIENCE

NV Energy, Las Vegas, NV

Sr. Project Manager | 2023-Present

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

Environmental Services Supervisor | 2022-2023

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

Sr. Environmental Advisor | 2016-2022

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

GE (General Electric Company); GE Hitachi Nuclear Energy, Sunol, CA

EHS Specialist | 2012-2016

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

NV Energy, Las Vegas, NV

Environmental Engineer | 2011-2012

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

Clean Harbors Environmental Services, West Sacramento, CA

Sr. Lead Chemist | 2007-2008

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

EDUCATION

California State University, Chico

Masters of Science in Environmental Science | 2011

University of California, Santa Barbara

Bachelor of Science in Environmental Studies | 2006

AFFIRMATION

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

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

Date: May 31, 2024


SEAN SPITZER

MARK WARDEN

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

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

Prepared Direct Testimony of

Mark Warden

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

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

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

A. I graduated from the University of Utah S.J. Quinney College of Law, with a Juris Doctor in Law in 1999 and a Bachelor of Arts from Brigham Young University in 1996. I have worked at the Companies for 13 years. Before joining the Companies, I worked for Bergman Companies developing commercial real estate projects. Prior to focusing on development, I worked as a business commercial attorney for Sempra Energy Solutions, Hunton & Williams LLC and DLA Piper. In my current role, I serve as the Director of Development for Renewable Energy and Origination. My responsibilities include the management and development of renewable energy

generation and storage assets from property evaluation through entitlements, to design and construction. My statement of qualifications is attached as **Exhibit Warden-Direct-1**.

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

A. In my current position, I lead a team of planners, engineers, analysts, and managers that manage all aspects for the development of renewable generation and storage projects owned by the Companies.

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

A. No.

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

A. The purpose of my testimony is to describe named placeholders in the Renewables section of the Supply Plan, provide an update on the Valmy Eavor PPA, Crescent Valley solar project, and White Pine pumped storage hydro in this 2024 Joint Triennial Integrated Resource Plan (“IRP”). Specifically, I introduce seven named placeholders the Companies are considering for future IRP filings and the ongoing due diligence occurring for Valmy Geothermal, Crescent Valley, and White Pine.

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

A. I am sponsoring the following Exhibit:

Exhibit Warden-Direct-1 – Statement of Qualifications

Additionally, I am co-sponsoring the following Technical Appendix:

Technical Appendix ECON-10 – Firm Dispatchable Resources

7. Q. PLEASE DESCRIBE NAMED PLACEHOLDERS IN THE ALTERNATIVE PLANS.

A. The Companies are naming placeholder resources for seven new utility-scale projects: two that are not located on Company-owned or controlled land, and five that are located on Company-owned or managed land. The two named placeholders that are not located on Company-owned or controlled land include Idaho Wind and White Pine pumped storage hydro. The five named placeholders on Company-owned or controlled land include Sierra Solar II, Amargosa I, Sierra Solar III, Amargosa II, and Amargosa III. The named placeholders are being included in response to the Commission Order in Docket No. 23-08015.¹ Sierra Solar II, Amargosa I, Sierra Solar III, Amargosa II, and Amargosa III were included because land acquisitions have occurred and permitting has commenced.

8. Q. PLEASE DESCRIBE THE STATUS OF THE IDAHO WIND PLACEHOLDER AND WHY THIS IS INCLUDED AS A NAMED PLACEHOLDER.

A. There are several large wind projects proposed in Idaho that are well in excess of the 952 megawatts (“MW”) placeholder for Idaho wind in the Alternative Plans. Idaho wind projects are anticipated to have high capacity factors that are complimentary to the Companies’ existing resource mix. The Companies own 952 MW of transmission rights on the Southwest Intertie Transmission Project (“SWIP North”) that is under development. The SWIP North project is expected to become

¹ April 9, 2024, Modified Final Order at 144, para. 333, and 150, para. 6.

operational in 2027. The Companies anticipate bringing projects forward in the next IRP to satisfy the SWIP North allocation; therefore, Idaho wind is included as a named placeholder.

9. Q. HOW DID THE COMPANIES DEVELOP PRICING ESTIMATES FOR THE NAMED PLACEHOLDER PROJECTS?

A. The Companies utilized National Renewable Energy Laboratory (“NREL”) published cost data that was further adjusted based on recent Request for Proposal (“RFP”) pricing, as applicable, to develop estimates for both future candidate resources and the named placeholder projects.

10. Q. PLEASE DESCRIBE THE COMPANIES’ APPROACH TO RENEWABLES AND STORAGE RFP AND ENERGY SUPPLY CONTRACTS IN CONJUNCTION WITH NAMED PLACEHOLDERS THAT ARE COMPANY OWNED.

A. The Companies anticipate submitting the projects currently identified as Named Placeholders for regulatory approval in future IRP filings after all project costs are clearly identified and after the projects have been deemed competitive in comparison to projects identified in future RFP filings.

11. Q. PLEASE DESCRIBE THE STATUS OF THE NORTH VALMY EAVOR PPA.

A. Sierra entered into a PPA with Eavor on November 4, 2022, for a 16-20 MW enhanced geothermal project near Valmy. Enhanced geothermal systems, like Eavor, bring the promise of 24/7 renewable energy that use less water than traditional geothermal operations. Since the contract execution, Eavor has

conducted gravity survey, a magneto-telluric survey, LiDAR and geologic field studies of the area. Eavor's geothermal engineers and scientists have determined that multiple subsurface faults exist and there will be a need to drill a deeper depth than initially contemplated prior to PPA execution. The subsurface geologic conditions increase the complexity of drilling and casing, and on May 22, 2024, Eavor provided formal notification to the Companies that the project is not commercially viable. Therefore, the Companies have removed Eavor from the economic analysis modeling and projected PCs from the RPS compliance forecast. Eavor has stated that they anticipate they will be able to build an Eavor system at Valmy in the future. If and when their technology does advance where this is possible, the Companies will work with Eavor to bring forth a newly negotiated PPA to the Commission for approval.

12. Q. PLEASE DESCRIBE THE STATUS OF CRESENT VALLEY AND WHY THIS PROJECT IS NOT BEING BROUGHT FORTH FOR REGULATORY APPROVAL.

A. The Companies have terminated the Asset Purchase Agreement between the Companies and Invenergy and do not, at present, intend to resubmit the Crescent Valley project to the Commission for approval.

13. Q. PLEASE DESCRIBE THE STATUS OF WHITE PINE PUMPED HYDRO PROJECT AND WHY THIS PROJECT IS INCLUDED AS A NAMED PLACEHOLDER.

A. White Pine Pumped Storage Hydro ("White Pine") is a 1,000 MW pumped storage hydro facility with eight hours of energy storage located in northern Nevada. The project developer is working towards Federal Energy Regulatory Commission

1 licensure, which is currently anticipated to be received in November 2026. The
2 commercial operation date (COD) of the project is expected in mid-2035.

3
4 The project is included as a named placeholder in the Alternative Plans because the
5 Commission has previously approved study money for it. The Companies continue
6 to see value in this facility and are evaluating several options to best add it to the
7 Companies' system. These options include purchasing and building the project as
8 an owned asset, entering into a tolling agreement with a purchase option, or entering
9 into a tolling agreement without a purchase option. The developer has provided
10 proposals for a variety of these options, but an agreement has not yet been reached.
11 As the Companies performed due diligence for the potential purchase, it was
12 determined that exposure to development and construction risks is reduced by
13 entering into a tolling agreement with a purchase option which would make it a
14 preferred method to acquire the capacity of the project.

15
16 Given the desire to seek a tolling agreement for the project, the Companies
17 anticipate including long-duration storage (including pumped storage hydro and
18 specifically White Pine) in future RFPs. This approach will allow the Companies
19 to examine the market for long-duration storage, compare long-duration storage
20 solutions across technologies and assure the most cost competitive project for
21 customers of the Companies.

22
23 **14. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?**

24 **A. Yes.**

EXHIBIT WARDEN-DIRECT-1

STATEMENT OF QUALIFICATIONS

Mark Warden
7155 Lindell Ave. Las Vegas, NV 89118
Mark.Warden@nvenergy.com
(702) 334-5616

PROFESSIONAL EXPERIENCE

NV Energy, Las Vegas, NV

Director, Renewables Development, July 2021 - Present

- Lead companies' efforts to develop renewables and storage projects

Senior Counsel, Assistant Secretary, February 2010 – June 2021

- Supported the renewables, generation and portfolio optimization departments in the negotiation and drafting of commercial transactions including acquisition, power purchase, engineering, trading, procurement, and procurement, engineering and construction agreements.
- Responsible for corporate secretary activities.

The Bergman Companies, San Jose, CA

Vice President, April 2007 – February 2010

- Lead a team developing commercial real estate projects including development, siting, permitting and construction.

Sempra Energy Solutions, Houston, TX

Director, April 2005 – April 2007

- Supported negotiation and drafting of commercial transactions in support of a wholesale and retail energy trading business.

Hunton & Williams (k/k/a Hunton Andrews Kurth), Dallas, TX

Associate, July 2001-June 2004

- Seconded to merchant energy company advising the client on commercial transactions including energy commodity and origination transactions.

EDUCATION

University of Utah, Salt Lake City, UT

Juris Doctorate, 1996

Brigham Young University, Provo, UT

Bachelor of Arts, 1993

Universidad Autonoma de Guadalajara, Guadalajara, United Mexican States

Diploma in Business Law, 1997

AFFIRMATION

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

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

Date: May 31, 2024


MARK WARDEN

KIMBERLY WILLIAMS

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

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

Prepared Direct Testimony of

Kimberly Williams

I. INTRODUCTION

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

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

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

A. My professional experience includes 25 years in the power industry, and I have a Bachelor of Science degree in Electrical Engineering. I have worked for the Companies since 2005. In addition to my work in Resource Planning and Analysis since 2020, I was Manager of Environmental Services for more than a decade and prior to that I was a Staff Environmental Engineer. As Manager of Environmental

Services, I led a team of environmental advisors engaged in environmental permitting and compliance for transmission assets and power plants representing more than 6,000 megawatts (“MW”) of system capacity.

Prior to joining the Companies, I was employed as a Regulatory Compliance Coordinator for Chevron’s independent power producing company for five years after holding a similar job at Berry Petroleum Company. Prior to that, I was a Facilities/Construction Engineer for ARCO Oil and Gas Company for eight years.

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

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

A. As Director of Resource Planning and Analysis, I lead a staff of economists, planners, engineers and analysts to develop the Companies’ Integrated Resource Plans (“IRP”) and amendments, and Energy Supply Plans and updates. In addition, working with other groups in the Companies, the Resource Planning and Analysis department develops and supports supply strategies, presents them to management for approval, and facilitates ongoing communication of the status of the supply plans.

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

A. Yes, I filed testimony with the Commission in the Companies’ 2021 Joint IRP, Docket No. 21-06001, in the Companies’ 2022 and 2023 Distributed Resources

Plan Updates, Docket Nos. 22-09001 and 23-09002, in the Companies' Fourth Amendment to the 2021 Joint IRP, Docket No. 22-11032, and in the Companies' Fifth Amendment to the 2021 Joint IRP ("Fifth Amendment"), Docket No. 23-08015.

II. OVERVIEW AND TESTIMONY ORGANIZATION

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

A. I sponsor the economic analysis used in the evaluation of the supply plans and the selection of the Preferred Plan in the 2024 Joint Integrated Resource Plan IRP 2025-2044 ("2024 Joint IRP").

I support the Companies' use of the updated Planning Reserve Margin ("PRM") and Effective Load Carrying Capabilities ("ELCC") developed by Energy and Environmental Economics ("E3") and reported in Technical Appendix ECON-12, the 2024 Resource Adequacy Study, sponsored by Nicolai Schlag of E3. I also support the Companies' use of the uncertainty reserves and Sierra Zonal Study developed by E3 and reported in Technical Appendices ECON-13 and ECON-14, respectively, both also sponsored by Mr. Schlag of E3.

Together with Dr. David Harrison of NERA Economic Consulting ("NERA"), I support the Environmental and Externalities results contained in Technical Appendix ECON-9.

I also support the incorporation of the Distributed Resource Plan (“DRP”) into the integrated planning process, economic analysis performed for various DSM scenarios, and the creation and analysis of the No Greenlink illustrative case.

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

A. I am sponsoring the following exhibits:

- **Exhibit Williams-Direct-1:** My statement of qualifications
- **Exhibit Williams-Direct-2:** Noticing, presentation, and summary of the January 10, 2024, consumer session

I am sponsoring the following Technical Appendices:

- ECON-1: Notice and Presentation from Stakeholder Briefings
- ECON-2: Description of Modeling Software
- ECON-3: Average Generation Costs for Preferred Plan - Redacted
- ECON-4: Summary of Production Cost Output for All Cases - Redacted
- ECON-5: Loads and Resources Tables
- ECON-6: Capital Projects (all cases and sensitivities) - Confidential
- ECON-7: PWRR (Production Costs plus Capital Costs)
- ECON-8: Area Diagram
- ECON-10: Candidate Resources – Redacted; sponsored jointly with the Companies’ witnesses John Lescenski and Mark Warden
- ECON-11: Marginal Energy Costs for Preferred Plan
- ECON-15: DSM Cases - Redacted
- ECON-16: No Greenlink Illustrative Case - Redacted

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

3 A. Yes. Technical Appendix ECON-6, Capital Projects, is confidential as are portions
4 of Technical Appendix ECON-3, Average Generation Costs for Preferred Plan,
5 Technical Appendix ECON-4, Summary of Production Cost Output for All Cases,
6 Technical Appendix ECON-10, Candidate Resources, Technical Appendix ECON-
7 15, DSM Cases, and Technical Appendix ECON-16, No Greenlink Illustrative
8 Case.

9
10 **8. Q. PLEASE EXPLAIN WHY ALL OR PART OF TECHNICAL APPENDICES**
11 **ECON-3, ECON-4, ECON-6, ECON-10, ECON-15, AND ECON-16 ARE**
12 **CONFIDENTIAL.**

13 A. ECON-3 contains unit-specific data which is considered market sensitive data.
14 ECON-4 contains proprietary forecast price data obtained from a third party.
15 Disclosure of such information would be a violation of the contractual agreement
16 the Companies have with the third party. ECON-6 and ECON-10 contain sensitive
17 projected capital cost information related to future resources. Public disclosure
18 could harm the Companies' ability to negotiate the best priced contracts moving
19 forward and would put the Companies at a competitive disadvantage. ECON-15
20 and ECON-16 each contain third-party proprietary forecast price data and sensitive
21 projected capital cost information related to future resources, as required for the
22 unique analyses performed in this IRP related to DSM and the No Greenlink
23 Illustrative case.

24
25 **9. Q. FOR HOW LONG DO THE COMPANIES REQUEST CONFIDENTIAL**
26 **TREATMENT OF THIS INFORMATION?**

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

2
3 10. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF THE
4 COMMISSION'S REGULATORY OPERATIONS STAFF ("STAFF") OR
5 THE NEVADA ATTORNEY GENERAL'S BUREAU OF CONSUMER
6 PROTECTION ("BCP") TO FULLY INVESTIGATE THE INFORMATION
7 SET FORTH IN THIS FILING?

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

11
12 11. Q. HOW IS YOUR TESTIMONY ORGANIZED?

13 A. In Section III, I discuss the near-term needs and the actions that the Companies will
14 take during the Action Plan period (2025-2027) to address these needs via
15 implementation of their Preferred Plan, a proposal that, if approved, will preserve
16 their ability to provide reliable electric service to customers in a manner that
17 balances reliability, cost, and decarbonization. In Section IV, I discuss the
18 economic analysis used in the selection of the Companies' Preferred Plan. In
19 Section V, I discuss the calculation of long-term avoided costs ("LTAC") and the
20 qualifying facility ("QF") limits. In Section VI, I describe how the Companies'
21 have incorporated Distributed Resources Plan ("DRP") into the integrated planning
22 process. In Section VII, I describe the economic analysis of varying levels of
23 demand side management ("DSM"). In Section VIII, I discuss analysis of an
24 illustrative case in which the Greenlink Nevada transmission line is not constructed.

1 **III. RESOURCE PLANNING IN THIS IRP**

2
3 **12. Q. PLEASE DESCRIBE THE COMPANIES' NEAR-TERM RESOURCE**
4 **NEEDS.**

5 **A.** In this 2024 Joint IRP, the Companies consider capacity needs related to an updated
6 load forecast projecting load growth as supported by the Companies' witness Tim
7 Pollard, impact of recent cancellations of previously approved renewable/storage
8 projects as described by the Companies' witness Jimmy Daghlion, and a desire to
9 minimize dependence on uncertain market capacity as supported by the
10 Companies' witness Ryan Atkins. The latter coincides with requirements for
11 participation in the Western Resource Adequacy Program ("WRAP") as described
12 further by Mr. Atkins. Overall, this 2024 Joint IRP illustrates a continued focus on
13 resource adequacy from prior filings. Mr. Schlag discusses new challenges and
14 added complexities in resource adequacy planning for the West in general and
15 summarizes implications for the Companies in his testimony.

16
17 In this 2024 Joint IRP, the Companies also consider the energy required to serve
18 the growing load, as well as the proportion of this energy that would need to be
19 supplied by renewable resources to meet Nevada's increasing Renewable Portfolio
20 Standard ("RPS") and address expected customer participation in the Nevada
21 GreenEnergy Rider ("NGR") program as supported by Mr. Spitzer. The 2024 Joint
22 IRP also addresses the impact of recent cancellations of previously approved
23 renewable/storage projects. In addition, while the Companies do not request
24 resources in this filing for this purpose, all plans in this filing target the Companies'
25 proportionate contribution to the state's 2050 clean energy goal.

Figure Williams-Direct-1 shows the system capacity requirements as updated in this 2024 Joint IRP. This figure, which duplicates Figure EA-4 in the Economic Analysis Section of the narrative, shows the system capacity requirements (loads plus PRM and reserves for Open Access Transmission Tariff (“OATT”) customers), existing resources (owned resources and those under contract and in service), and resources approved but not in service (less recently cancelled renewable projects including Hot Pot, Iron Point, Southern Bighorn, Chuckwalla, Boulder Solar III, and Eavor).¹ The updated base load forecast put forth in this 2024 Joint IRP was used, and thermal units are shown at their peak capacities derated for their annual average forced outage rate while renewable units have been adjusted for their effective load carrying capability (“ELCC”), consistent with use of an unforced capacity, or UCAP, PRM, which I will discuss more in Section IV of my testimony.

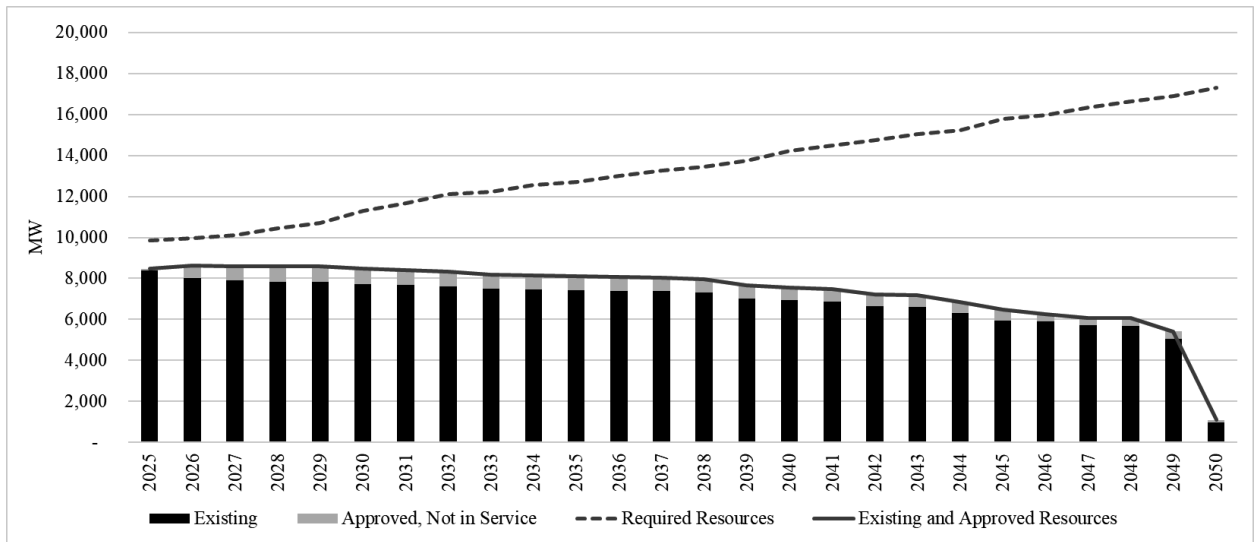
///

///

///

¹ NV Energy’s witness Mr. Daghlion discusses in his direct testimony the Companies’ removal of the Boulder Solar III PV/BESS (approved in Docket No. 20-07023) and Eavor geothermal projects. Other projects removed in recent filings, as mentioned by Mr. Daghlion, include Hot Pot PV/BESS, Iron Point PV/BESS, Chuckwalla PV/BESS, and Southern Bighorn Solar PV/BESS.

**FIGURE WILLIAMS-DIRECT-1
NV ENERGY CAPACITY POSITION**

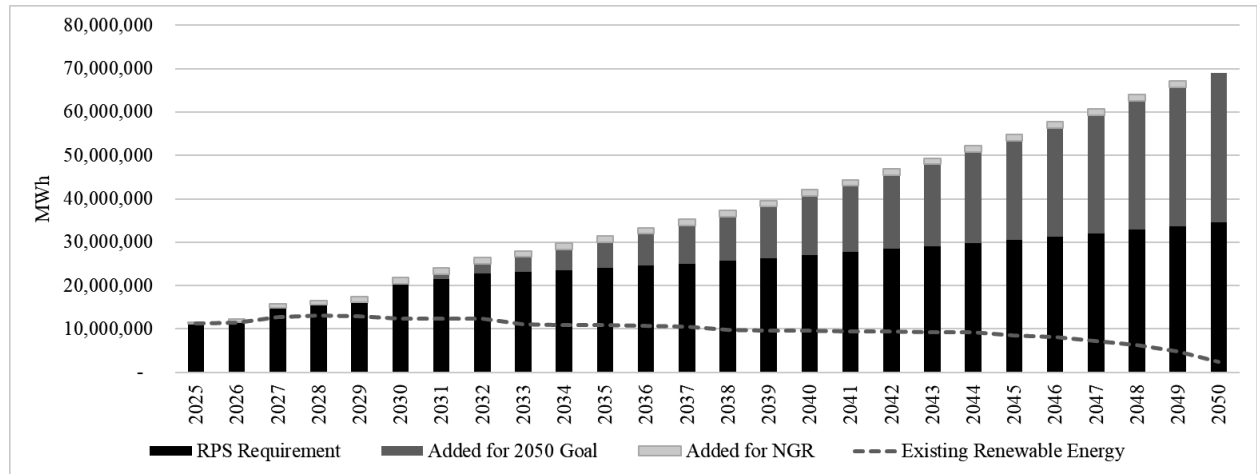


The growing load and loss of cancelled projects creates a need for increased resources or market capacity purchases. The First, Fourth, and Fifth Amendments to the 2021 IRP worked to reduce reliance on market capacity purchases due to concerns about uncertain availability and deliverability. These concerns persist, as described by Mr. Atkins in his prepared direct testimony, and this IRP continues the focus on reducing reliance on market capacity purchases. Replacing cancelled resources and reducing reliance on uncertain market availability and deliverability while addressing load growth may all be deemed to be actions that improve resource adequacy in this amendment.

The loss of previously approved renewable projects as described in prior IRP filings also impact projected RPS compliance and the NGR program, shortening the timeframe before noncompliance unless incremental renewable resources are added to the portfolio as described in the prepared direct testimony of Mr. Daghljan and Mr. Spitzer. The loss of renewable resources also impacts the trajectory towards the Companies' share of the state's 2050 clean energy goal. **Figure Williams-**

Direct-2, which duplicates Figure EA-5 in the Economic Analysis section of the narrative, offers an approximation of the net renewable energy the Companies may need in future years.

**FIGURE WILLIAMS-DIRECT-2
NV ENERGY NEED FOR ADDITIONAL RENEWABLE ENERGY**



13. Q. HOW ARE TRANSMISSION PROJECTS INCLUDED IN THE COMPANIES' ECONOMIC ANALYSIS?

A. Transmission infrastructure required to facilitate near-term resources, as discussed in the Transmission Plan and sponsored by the Companies' witness Charles Pottey, is included as applicable in each case/plan studied. All cases and plans studied include the transmission infrastructure driven by large customer loads as presented in the Transmission Plan and sponsored by the Companies' witnesses Layne Maxfield and Charles Pottey. All cases and plans studied also include the updated Greenlink Nevada budget, which represents an increase from the original estimate for the project as presented in the Transmission Plan and sponsored by the Companies' witnesses Shahzad Lateef. As mentioned previously, economic analysis of an illustrative case in which the Greenlink Nevada transmission line is not constructed is discussed in Section VIII of my direct filed testimony.

14. Q. ARE THERE ANY RESOURCES FOR WHICH APPROVAL IS REQUESTED IN THE PRAYER FOR RELIEF THAT WERE NOT PART OF THE ECONOMIC ANALYSIS? IF SO, WHY?

A. Yes. Approval is requested in the prayer for the Corsac geothermal PPA and associated transmission infrastructure, but this project was not included in the economic analysis. This project is intended to be “sleeved” to a single customer under an energy supply agreement (“ESA”) as described in the Renewables Section of the Supply Plan narrative and supported by the Companies’ witnesses Mr. Spitzer and Janet Wells. As this resource is not requested for the purpose of serving bundled retail customers, it is excluded from the economic analysis in this IRP. As the negotiation for the ESA and sleeved PPA were resolved late in the development of the IRP, it was not possible to include the transmission infrastructure capital in the economic analysis.²

15. Q. PLEASE DESCRIBE ANY PUBLIC AND/OR STAKEHOLDER ENGAGEMENT THAT OCCURRED DURING THE DEVELOPMENT OF THE 2024 JOINT IRP.

A. NRS § 704.744.2, created by Assembly Bill 524 in the 2023 legislative session, requires an electric utility to schedule a consumer session before filing an IRP or an amendment to an IRP. The Companies held a consumer session for interested persons on January 10, 2024, at the Commission’s offices in Las Vegas and Carson City with a call-in phone option in which a presentation by the Companies’ personnel provided information on the progress in developing plans, key assumptions being applied, and results available at the time. All attendees were provided an opportunity to speak. Notice of the session, the presentation made at

² This generator transmission interconnection cost is estimated at \$2 million and is further described in the Transmission Plan.

the session, and a summary of public comments made at the session are provided in **Exhibit Williams-Direct-2**.

Additionally, pursuant to NAC § 704.952(5), the Companies conducted a meeting for interested persons, dubbed a “stakeholder briefing,” to inform the Commission’s Regulatory Operations Staff (“Staff”), personnel from the Bureau of Consumer Protection (“BCP”) and interested parties of preliminary key modeling assumptions and to provide an overview of the 2024 Joint IRP. The meeting took place via Microsoft Teams on January 31, 2024. Notice of the meeting and the presentation made at the meeting are provided in Technical Appendix ECON-1.

Subsequently, an additional stakeholder briefing was held shortly before filing the 2024 Joint IRP via Microsoft Teams on May 22, 2024. Notice of this session is also provided in Technical Appendix ECON-1.

IV. ECONOMIC ANALYSIS AND SELECTION OF THE PREFERRED PLAN

16. Q. PLEASE DESCRIBE THE METHODOLOGY USED TO PERFORM THE ECONOMIC ANALYSIS OF THE PLANS CONSIDERED IN THIS FILING.

A. The Companies first assess their need for future resources given forecast customer load growth, required and anticipated interest in renewable generation, reliability requirements, and any system obligations. The Companies’ analysis of future resource requirements begins with the Loads and Resources Tables (“L&R Tables”). A long-term forecast of annual coincident peak loads, planning reserve requirements, and a forecast of planning capacity for supply-side and demand-side

resources are used to determine the Companies' open capacity position ("open position") for each year under base (or mid) load conditions. The open position is the portion of the utility's capacity needs that are not met by resources under utility ownership or long-term contract.

The Companies use Energy Exemplar's PLEXOS Energy Modeling Software for the economic analysis of this 2024 Joint IRP. The software tool PLEXOS LT's least cost optimization is used to develop a base case – a long term portfolio that includes existing and approved projects and future placeholder resources to fill the anticipated need – meeting the forecast load plus PRM, the state's RPS, anticipated customer participation in the NGR program, and the Companies' proportionate contribution to the state's 2050 clean energy goal. The base case is built to meet the reliability criterion using the candidate supply resources described in the Plan Development subsection of the Economic Analysis in the Supply Side narrative, which include paired PV/BESS, standalone PV, standalone BESS, geothermal, Nevada wind, Idaho wind, pumped storage hydro, combustion turbine peaking units, and firm dispatchable resources. Plans are created from the base case with varying available projects in lieu of placeholder resources. For scenarios with dramatically different long-term goals, such as those required by NRS § 704.741(3)(c)(1) and (2), distinct expansion plans were created in PLEXOS LT.

Next, the Companies utilize additional software tools to evaluate each plan over the planning period. The first is the PLEXOS ST ("PLEXOS") production cost model. PLEXOS computes overall production cost (fuel, purchase power, variable and fixed costs to operate) by performing hourly, chronological economic unit commitment and dispatch of the Companies' electric production resources and

1 market purchases to satisfy hourly load requirements in a least-cost solution over
2 the study period. The second model used is a spreadsheet workbook called the
3 Capital Expense Recovery model (“CER”). The CER computes the annual revenue
4 requirements to recover expenses associated with the capital costs of utility-owned
5 resources, such as future generators or transmission infrastructure. Note that
6 transmission infrastructure included in the CER may be associated with a
7 generating or storage resource or may be unrelated to any identified resource in a
8 plan. Only native load allocations of transmission-related costs are included in the
9 CER.

10
11 The sum of the annual production costs from PLEXOS and the annual capital
12 revenue requirements from the CER over the study period, discounted by each
13 company’s weighted average cost of capital, provides the Present Worth of
14 Revenue Requirement (“PWRR”) for each plan. A comparison of the PWRRs from
15 each plan provides a ranking of the plans from least cost to greatest cost. This
16 ranking is only one factor used to determine the selection of alternative plans and
17 ultimately, selection of the Preferred and Alternate Plans. Other important factors
18 that affect the selection of these plans include, but are not limited to, resource
19 adequacy, reliability, risk mitigation, resource and fuel diversity, RPS performance,
20 consistency with Nevada’s energy policies, carbon emissions, and the needs of
21 individual customers.

22
23 The Companies then conduct scenario analysis for the alternative plans around the
24 major assumptions of load forecasts, fuel and purchase power forecasts, and carbon
25 policy forecasts. The scenario analysis tests how the economic analysis results
26 change under variations around those major assumptions. The major assumptions
27

of load, fuel and purchase power forecasts, and carbon policy forecasts have inherent volatility since no one forecast for these major assumptions can be assumed to have perfect certainty. Analyzing the alternative plans across varying levels of assumptions allows the Companies to evaluate how the cases perform under a range of load, market, and carbon policy outcomes. Material PWRR differences between cases under one scenario versus another may factor into the selection of the Preferred Plan. Depending on circumstances, the Companies may analyze additional scenarios.

17. Q. PLEASE DESCRIBE THE MOST NOTEWORTHY UPDATES OF KEY MODELING ASSUMPTIONS USED IN THE ECONOMIC ANALYSIS.

A. The economic analysis uses the updated base load forecast, addresses updated base fuel and purchase power price forecasts including expectations for the impact of federal carbon policy, and meets anticipated customer participation in the NGR program in addition to meeting the RPS in every year. As in recent filings, the economic analysis targets the Companies' proportionate contribution to the state's 2050 clean energy goal, meets the PRM for the Companies and includes required reserves to be held for OATT customers. The load forecast is sponsored by Mr. Pollard. The fuel and purchase power price forecasts are sponsored by the Companies' witness Zeljko (Zack) Vukanovic, the assessment of federal carbon policy is sponsored by NERA's Dr. Harrison, and the assessment of the RPS and NGR is sponsored by Mr. Spitzer.

In the 2024 Resource Adequacy Study, supported and discussed further by Mr. Schlag, the Companies' ELCC values and PRM requirement have been refreshed using the updated base load forecast and resource portfolio (existing and approved

resources) in a Loss of Load Probability (“LOLP”) model to ensure the Companies can maintain resource adequacy. As before, the Companies employ a “1-day-in-10-year” loss of load planning standard to ensure the joint system has an adequate supply of resources. For this update, the PRM was calculated for the joint system utilizing an unforced capacity (“UCAP”) accounting method, which reduces the peak summer capacity of thermal generation resources by each resource’s forced outage rate. In past filings, the Companies have used the installed capacity (“ICAP”) method for determining the PRM, in which the impact of thermal forced outage rates was captured in the PRM itself rather than in the capacity accreditation. As explained by Mr. Schlag, the UCAP capacity accreditation method aligns more closely with the ELCC approach used to accredit renewables and storage in expansion planning, increases the stability of the PRM requirement over time, and is also consistent with proposed accreditation methods under WRAP. The updated analysis indicates a joint system UCAP PRM requirement of 12.5 percent for this 2024 Joint IRP, equivalent to an ICAP PRM in the range of 16 to 17 percent. A detailed description of the methodology and data used for the updated ELCC and PRM calculation, as well as further description of the change from ICAP to UCAP accounting method, is provided in the 2024 Resource Adequacy Study performed by E3, provided in Technical Appendix ECON-12, sponsored by Mr. Schlag.

As described by Mr. Atkins, the Companies set an open capacity position target of no more than 750 MW in 2028 and every year thereafter to limit reliance on uncertain market availability and deliverability, which poses significant reliability risk to the Companies. This target aligns with NV Energy’s intent to become financially binding in WRAP in winter 2027-2028, also supported by Mr. Atkins.

1 The Companies updated the L&R tables to utilize NV Energy's coincident peak
2 loads rather than the non-coincident peaks that were used in previous filings. This
3 change is consistent with the analysis used to create the updated PRM as described
4 by Mr. Schlag. Additionally, as part of the change to UCAP accounting, the
5 capacity contributions in the L&R tables for the Companies' thermal generating
6 fleet were adjusted to account for historic outage rates. This update creates an
7 effective capacity for thermal units similar to the ELCC used for renewable
8 resources.

9
10 The existing DSM air conditioning load management program, previously modeled
11 as a reduction to the load forecast, is modeled as a fixed supply resource in this
12 2024 Joint IRP. In addition, certain future DSM and DRP programs are modeled as
13 supply resources in this IRP. As such, these resources are shown in the L&R tables
14 and are modeled in PLEXOS. These resources, as modeled, are shown in Figure
15 EA-8 in the Economic Analysis Section of the Supply Plan narrative. The modeled
16 DSM and DRP programs, determined early in the IRP planning process, differ from
17 the proposed programs as described in the DSM Plan and DRP of this 2024 Joint
18 IRP and supported by the Companies' witnesses Marie Steele and Patricia
19 Rodriguez.

20
21 The economic analysis removes the previously approved Boulder Solar III
22 PV/BESS and Eavor geothermal projects.

23
24 Consistent with the 2024 Resource Adequacy Study, forced outage rates of 5
25 percent were introduced in the production cost modeling for standalone BESS in
26 this 2024 Joint IRP.

1 The contingency reserve requirement was updated for this IRP with a dynamic
2 calculation that captures the hour-by-hour conditions and operating needs of the
3 system. The uncertainty reserve analysis was performed by E3, is provided in
4 Technical Appendix ECON-13, and is supported by Mr. Schlag.

5
6 Transmission limits, including access to external markets as well as limits between
7 the Companies were modeled in accordance with Technical Appendix ECON-8. It
8 is noteworthy that, while the Companies have included an expectation that
9 Southwest Intertie Project-North (“SWIP-N”) would allow access to Idaho Wind
10 placeholder resources as stated in the Transmission Plan Section of the Supply Side
11 narrative and sponsored by Mr. Pottey, they do not rely on SWIP-N for market
12 access at this time as construction of this line is not under the Companies’ control.

13
14 For the alternative plans, the Companies have included “named placeholders.”
15 These placeholders are known, likely future projects that the Companies may
16 contract or acquire as supported by the Companies’ witness Mark Warden. These
17 projects are not being requested in this filing but are included based on currently
18 available information. Inclusion of these named placeholders addresses a directive
19 within ordering paragraph 6 in the Commission’s March 1, 2024, Order in the Fifth
20 Amendment.³ Anticipated company-owned projects are modeled as company-
21 owned, rate-based assets in the CER and anticipated PPAs are modeled in the
22 production cost model with the anticipated PPA pricing. Named placeholders
23 include the appropriate estimated project-specific transmission infrastructure costs
24 based on location as currently known.

25
26
27 ³ Docket No. 23-08015, April 9, 2024, Modified Final Order at 150.

Cost estimates for Greenlink Nevada are included in the CERs due to the change in the overall project costs and the request for incremental project cost approval included in this filing. Revenue requirements for Greenlink Nevada are shown for the 26-year study period, 2025 to 2050. As they are included in all plans, they do not affect PWRR rankings.

18. Q. PLEASE DESCRIBE THE BASE CASE CREATED FOR THIS IRP.

A. The Base Case builds on the Fifth Amendment preferred plan with modifications as approved by the Commission and as described previously in my direct testimony. As previously described, the Base Case is the result of a PLEXOS LT least cost expansion that meets the PRM requirement, RPS requirement, anticipated customer participation in the NGR program, and targets the Companies' proportionate contribution to the state's 2050 clean energy goal. The Base Case relies heavily on market capacity purchases in the near term, reducing it significantly by 2027 and keeping it below 750 MW throughout the study period. It includes a variety of placeholder resource types as part of a least cost buildout, including one set of two simple cycle combustion turbines ("CTs") and substantial amounts of PV and 4-hour BESS, as well as geothermal, pumped storage hydro, Nevada Wind, Idaho Wind accessed via LS Power's planned SWIP-N transmission line, and future firm dispatchable resources. The near-term resources – those added through 2028 – in the Base Case include approximately 420 MW of CTs, nearly 1,300 MW of PV, and more than 700 MW of BESS.

19. Q. PLEASE DESCRIBE THE SCREENING OF AVAILABLE PROJECTS IN THIS IRP.

A. The Companies investigated a diverse set of incremental resources that could fill a portion of the Companies' near-term need for additional capacity and renewable portfolio credits ("PCs"). These resources are described in detail in the Renewables and Generation Sections of the narrative and supported by the Companies' witnesses Mr. Lescenski and Mr. Spitzer. The resources that progressed to the economic analysis are shown, as analyzed, below.

- Two CTs at Valmy. Replaces Base Case placeholder resources with approximately 415 MW of summer peak capacity. This project will be in service by June 2028. These units will be located at the existing North Valmy Generating Station in Humboldt County, Nevada, and will be owned and operated by Sierra.
- Two CTs at Ft. Churchill. Replaces Base Case placeholder resources with approximately 415 MW of summer peak capacity. The in-service date for this project is June 2029. These units will be located at the existing Ft. Churchill Generating Station in Yerington, Nevada, and will be owned and operated by Sierra.
- Two CTs at Harry Allen. Replaces Base Case placeholder resources with approximately 450 MW of summer peak capacity. The in-service date for this project is June 2030. These units will be located 30 miles north of Las Vegas at the existing Harry Allen Generating Station and will be owned and operated by Nevada Power.
- Two CTs at Higgins. Replaces Base Case placeholder resources with approximately 440 MW of summer peak capacity. The in-service date for this project is June 2029. These units will be located at the existing Walter M.

Higgins Generating Station in Primm, Nevada, and will be owned and operated by Nevada Power.

- Dry Lake East PV/BESS. Replaces Base Case placeholder resources with a PPA consisting of 200 MW of PV paired with 200 MW BESS with an in-service date of December 2026. Capacity is allocated solely to Nevada Power.
- Boulder Solar III PV/BESS. This new version of the cancelled Boulder Solar III PV/BESS PPA approved in Docket 20-07023 replaces Base Case placeholder resources with 128 MW of PV paired with 128 MW BESS with an in-service date of June 2027. Capacity is allocated solely to Nevada Power.
- Libra PV/BESS. Replaces Base Case placeholder resources with a PPA consisting of 700 MW of PV paired with 700 MW BESS with an in-service date of December 2027. For the individual project screening, the Libra PV/BESS was allocated solely to Nevada Power due to its large size. In subsequent analyses, multiple scenarios with various allocations between Nevada Power and Sierra were evaluated and are further described in the Combination Case Analysis below.
- Geo-1. Replaces Base Case placeholder resources with a PPA consisting of a portfolio of geothermal projects totaling 152 MW with varying in-service dates. Capacity is allocated solely to Sierra.
- Solar-1. Replaces Base Case placeholder resources with a PPA consisting of 57 MW PV paired with 57 MW BESS with an in-service date of April 2026. Capacity is allocated exclusively to Nevada Power.
- Battery-1. Replaces Base Case placeholder resources with an 80 MW BESS PPA with an in-service date of May 2026. Capacity is allocated solely to Nevada Power.

- Solar-2. Replaces Base Case placeholder resources with a PPA consisting of 200 MW PV paired with 200 MW BESS with an in-service date of March 2028. Capacity is allocated entirely to Nevada Power.
- Wind-1. Replaces Base Case placeholder resources with a PPA consisting of 500 MW of wind with an in-service date of December 2028. Capacity is allocated exclusively to Sierra.

The Companies screened these projects as shown in the Individual Project Screening in the Plan Development subsection of the Economic Analysis Section of the narrative. Three of the CT projects (Harry Allen, Valmy, and Higgins) as well as the large Libra PV/BESS and the Battery-1 standalone BESS appear to be economic when compared to the Base Case but, of these, only the Libra project actively contributes to the RPS.

All the projects screened assist in adding varying amounts of capacity, and all supply capacity after solar resources drop off in the evening hours either in the form of fossil units, BESS, geothermal, or wind. Several comparisons of similar resource types are presented in the Economic Analysis Section of the narrative.

Due to ongoing due diligence in the Request for Proposal (“RFP”) process simultaneous with the economic analysis, several of the projects were subsequently removed from consideration in this filing. This is discussed in the Renewables Section of the narrative and supported by Mr. Spitzer.

Based on the results of the individual screening and after removal of several projects from consideration in the RFP due diligence, the Companies analyzed a set

of preliminary combinations of projects before selecting a final set of alternative plans. The following projects were further evaluated in the combination cases:

- Harry Allen CTs
- Valmy CTs
- Higgins CTs
- Libra PV/BESS
- Boulder Solar III PV/BESS
- Dry Lake East PV/BESS

20. Q. PLEASE DESCRIBE THE COMBINATION CASES THAT WERE CREATED.

A. The Companies continued their analysis by developing a set of cases in which combinations of available projects are added to the Base Case, with adjustment of placeholder resources such that the open positions and systemwide RPS and NGR attainment of each combination case are as similar as possible. Additionally, the Combination Cases were developed subject to the following conditions:

- No placeholder resources in the Action Plan period (2025-2027);
- Placeholder resources in 2028 are also eliminated;
- To the extent possible, open positions remain at or below 750 MW starting in 2028;
- When possible, renewable energy requirements are met without the need to use previously banked PCs; and,
- Near-term CTs are limited to only one set of CTs, or approximately 420 MW, consistent with the selection of one set of near-term CTs in the Base Case.

The following combination cases were created:

- VBDL1. Valmy CTs, Boulder Solar III PV/BESS, Dry Lake East PV/BESS, and Libra PV/BESS. Libra is allocated to Nevada Power.
- IBDL3. Higgins CTs, Boulder Solar III PV/BESS, Dry Lake East PV/BESS, and Libra PV/BESS. Libra is allocated 50 percent to Nevada Power and 50 percent to Sierra.
- ABDL3. Harry Allen CTs, Boulder Solar III PV/BESS, Dry Lake East PV/BESS, and Libra PV/BESS. Libra is allocated 50 percent to Nevada Power and 50 percent to Sierra.
- BDL2. Boulder Solar III PV/BESS, Dry Lake East PV/BESS, and Libra PV/BESS. Libra is allocated 60 percent to Nevada Power and 40 percent to Sierra.

It is noteworthy that all the combination cases include the Boulder Solar III PV/BESS, Dry Lake East PV/BESS, and Libra PV/BESS projects, as they are all needed to satisfy the RPS requirement. Libra PV/BESS is also needed in all cases to satisfy the Companies' open position goals. Even with the addition of these PV/BESS projects, the Companies are expected to use banked PCs to meet the state's RPS mandates and company credit commitments (NGR, ESA, and 704B obligations) in the early years of the study period.

Of all the siting options studied for the addition of two CTs, only the Valmy location has the benefit of eliminating the existing Valmy steamer must-run requirement as described in the Transmission Section of the narrative. Without the two fast start peaking units at the Valmy location, the Valmy steamer must-run requirement continues in perpetuity due to the load growth in the region. It is also

noteworthy that CTs at this location do not compete for natural gas availability with Sierra's local gas distribution company in Reno/Sparks.

The open positions and PWRR of the combination cases are presented in the Economic Analysis Section of the narrative. The combination case with two CTs at Valmy had the lowest PWRR of all combination cases in both the 20- and 26-year horizons. The combination case that did not include *any* CTs (BDL2) had the highest PWRR in both the 20- and 26-year horizons. This outcome is consistent with the selection of two near-term CTs in the least cost buildout from PLEXOS LT. More observations on these cases are presented in the Economic Analysis Section of the narrative.

21. Q. PLEASE DESCRIBE THE CREATION OF THE ALTERNATIVE PLANS PRESENTED IN THIS FILING.

A. Informed by the analysis of the combination case as well as statutory requirements, the Companies created a diverse set of alternative plans. Two of the plans are updated versions of combination cases. Two additional plans address scenarios specified in the NAC and NRS.

Balanced Plan. The least cost case from the combination case evaluation, VBDL1, was chosen to move forward in the alternative plan analysis as it represents a balanced approach towards meeting the capacity needs in this filing as well as the State's, Companies', and customers' renewable energy needs while minimizing cost impact on customers. This plan was named the Balanced Plan and combines new CTs at Valmy, Boulder Solar III PV/BESS, Dry Lake East PV/BESS, and Libra PV/BESS projects. Libra's capacity is allocated entirely to Nevada Power in this

plan. The projects add near-term capacity in 2027 and 2028, reduce the Companies' dependence on uncertain market capacity purchases, contribute to RPS and NGR needs, and supply energy after solar resource output declines in the evening hours. The Valmy CTs enable the removal of the existing Valmy steamer must-run requirement as described in the Transmission Section of the narrative and do not compete for natural gas availability with Sierra's local gas distribution company in Reno/Sparks.

Renewable Plan. The combination case that adds only renewable and storage projects, BDL2, was chosen to move forward in the alternative plan analysis as an option that adds no near-term thermal projects. This plan was named the Renewable Plan and combines Boulder Solar III PV/BESS, Dry Lake East PV/BESS, and Libra PV/BESS. In this plan, Libra's capacity is allocated 60 percent to Nevada Power and 40 percent to Sierra. While the projects add near-term capacity in the same early years as the Balanced Plan, less capacity is added in 2028. The lack of near term CTs results primarily in incremental BESS placeholders in 2030 in order to ensure similar open positions to the Balanced Plan. Without the two fast start peaking units at the Valmy location, the Valmy steamer must-run requirement continues in perpetuity in this plan due to the load growth in the region.

Low Carbon Plan. NAC § 704.937(1) contains a requirement for a scenario of low carbon dioxide emissions in triennial Integrated Resource Plans submitted on or before June 1, 2027, that "uses sources of supply that result in, by the year 2030, an 80 percent reduction in carbon dioxide emissions from the generation of electricity to meet the demands of customers of the utility as compared to the amount of such emissions in the year 2005," while also meeting the state's 2050

clean energy goal and including the deployment of distributed generation. The Companies refer to the alternative plan that addresses this requirement as the Low Carbon Plan. The Companies created a new PLEXOS LT expansion plan to develop this plan, utilizing the same load, PRM requirement, and candidate resources as the base case expansion but adding new build constraints for a greater renewable energy requirement, beginning in 2027, to meet the 2030 carbon dioxide emissions goal. The presumed retirement dates of existing resources were not changed in the creation of this plan. Notably, the least cost reliable buildout from PLEXOS LT that meets the requirements for this low carbon scenario includes, in 2050, the same amount of gas-fired and firm dispatchable resources – resources modeled as gas turbines – as the Base Case. In other words, the least cost reliable buildout adds incremental firm dispatchable resources in this scenario just as it did for the Base Case, regardless of the aggressive, early renewable/storage buildout to meet the particular goals of this scenario. The Low Carbon Plan adds no near-term thermal generation and combines Boulder Solar III PV/BESS, Dry Lake East PV/BESS, and Libra PV/BESS. Libra’s capacity is allocated 100 percent to Nevada Power in this plan. Without the two fast start peaking units at the Valmy location, the Valmy steamer must-run requirement continues in perpetuity in this plan due to the load growth in the region. A significant increase in near-term renewable placeholders is needed in this plan to comply with carbon dioxide reduction requirements.

No Open Position Plan. NRS § 704.741(3)(c)(2), while not yet detailed in the Nevada Administrative Code, directs the Commission to require utilities to include at least one scenario in a supply plan that “provides for the construction or acquisition of energy resources through contract or ownership to be placed into service to close an open position utilizing dedicated energy resources in this State

and dedicated energy resources delivered through firm transmission.” Moreover, a “significant share of the renewable energy facilities and energy storage systems included in the scenario must be owned by the utility.” The Companies refer to the alternative plan that addresses this requirement as the No Open Position Plan. The Companies created a new PLEXOS LT expansion plan to develop this plan. This PLEXOS LT run used the same load, PRM requirement, and candidate resources as the base case expansion but permitted no market capacity purchases beginning in 2028. Notably, two sets of CTs were selected in the early years in this expansion buildout. This plan includes two CTs at each of the Valmy and Harry Allen Generating Stations, as well as Boulder Solar III PV/BESS, Dry Lake East PV/BESS, and Libra PV/BESS. Libra’s capacity is allocated solely to Nevada Power in this plan. As with the Balanced Plan, the Valmy CTs enable the removal of the existing Valmy steamer must-run requirement as described in the Transmission Section of the narrative and do not compete for natural gas availability with Sierra’s local gas distribution company in Reno/Sparks.

These plans all reduce the Companies’ open position, meet the PRM and RPS requirements as well as anticipated participation in the NGR program, and target the Companies’ proportionate contribution to the state’s 2050 clean energy goal. All four plans add a substantial amount of PV and BESS project nameplate, which contribute significantly to both capacity and renewable energy needs. Two of the plans add near-term peaking CTs for low cost capacity and around-the-clock firm dispatchable resources.

22. Q. PLEASE DESCRIBE THE USE OF NAMED PLACEHOLDERS.

A. “Named placeholders” were incorporated into all four alternative plans to address Directive 6 of the Commission’s April 9, 2024, Modified Final Order in the Fifth Amendment. Named placeholders are provided to represent reasonably known projects in progress or requested and to reflect anticipated Company-owned projects. These are presented with estimated cost/pricing including anticipated associated transmission infrastructure costs and are described further in the Renewables Section of the Supply Plan narrative and are supported by Mr. Warden. The Companies are not requesting approval of any of the named placeholders, and all placeholders are subject to change as needs and circumstances change in future filings. The named placeholders are identical between the Balanced Plan and Renewable Plan, but necessarily different in the Low Carbon Plan and No Open Position Plan due to the different buildouts in these two plans to achieve their required goals. A comparison of the full buildout for each plan is provided in Figures EA-21 and EA-22 in the Economic Analysis Section of the Supply Side narrative.

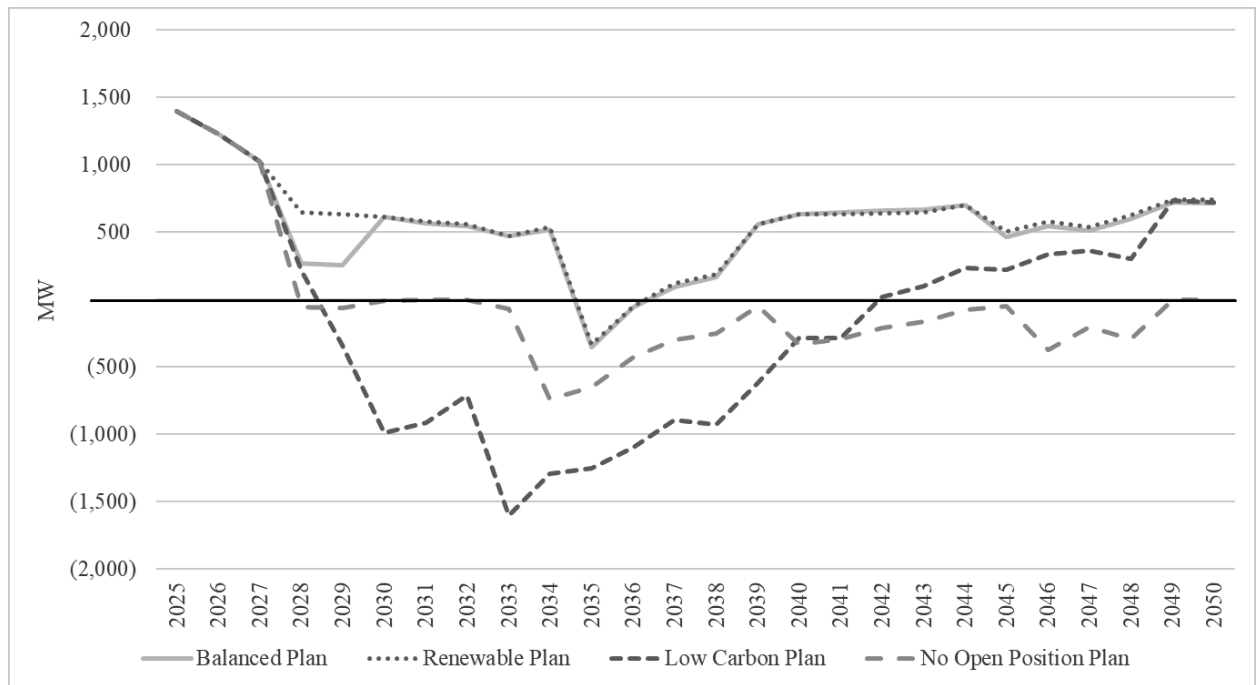
The two alternative plans that were developed from combination cases were purposefully created to differ from the combination cases only in the inclusion of named placeholders.

23. Q. PLEASE PROVIDE AN OVERVIEW OF THE CAPACITY POSITIONS FOR THE ALTERNATIVE PLANS.

A. The capacity positions for the alternative plans are shown in **Figure Williams-Direct-3**, which duplicates Figure EA-23 in the Economic Analysis Section of the narrative. Note that when a plan’s representative line falls below the graph’s zero mark, it indicates that the Companies have acquired more resources than are needed

to meet load plus reserve requirements. This excess, or long position, may occur when resources are added to meet goals beyond capacity needs or when an added resource size is large relative to the open position. The No Open Position Plan closes the open position by 2028 and the Low Carbon Plan does so by 2029. While the Low Carbon Plan has no requirement to close the open position, the aggressive buildout required to meet the 2030 Low Carbon goal results in an excessively long position from 2029 to 2041. The Balanced Plan and Renewable Plan achieve the 750 MW open position target by 2028 and maintain it through the study period.

**FIGURE WILLIAMS-DIRECT-3
CAPACITY POSITIONS FOR ALTERNATIVE PLANS (BASE LOAD)**



24. Q. DOES THE ADDITION OF FOSSIL GENERATION IN SOME ALTERNATIVE PLANS PRECLUDE THE ACHIEVEMENT OF CLEAN ENERGY GOALS?

A. No. As stated previously, all plans achieve the RPS systemwide in all years as well as the anticipated customer participation in the NGR program and, as in the last

several IRP filings, target the Companies’ proportionate contribution to the state’s 2050 clean energy goal. While the Low Carbon Plan follows a different trajectory towards the state’s 2050 goal, with dramatically reduced carbon dioxide emissions by 2030, the three other plans follow a very similar trajectory despite differences in near term fossil resources in each plan. In 2050, the Low Carbon Plan has the same amount of firm dispatchable resources – resources modeled as gas turbines – as the Balanced Plan. Figure EA-25 in the Economic Analysis Section of the narrative, provides a comparison of the net renewable energy of each plan relative to the RPS, expected NGR participation, and the state’s 2050 clean energy goal.

The year-by-year projected carbon dioxide emissions for each plan, including emissions associated with market energy as estimated by NERA, are shown in Figure EA-26 in the narrative.

Figure EA-28 in the Economic Analysis Section of the narrative illustrates each plan’s zero-carbon generation in 2050 relative to the state’s 2050 clean energy goal, illustrating that all plans achieve this target. Note that, as modeled, all plans include carbon dioxide emitting firm dispatchable resources in 2050 – approximately 7,000 MW nameplate in the Balanced Plan, Renewable Plan, and Low Carbon Plan, and nearly 8,000 MW nameplate in the No Open Position Plan.

25. Q. WHY ARE FIRM DISPATCHABLE RESOURCES IMPORTANT IN A DECARBONIZING PORTFOLIO?

A. As discussed extensively in recent filings and illustrated for the Balanced Plan in Figures EA-31 and EA-29 in the Economic Analysis Section of the narrative, thermal units as well as other firm dispatchable resources, which are modeled today

as gas turbines, contribute much more significantly to firm capacity in a decarbonized future such as that shown in the later years in the Balanced Plan than they do to energy production, resulting in a positive impact on resource adequacy from a strong contingent of firm dispatchable resources with minimal potential carbon dioxide emissions.

26. Q. WHAT WERE THE RESULTS OF THE FINAL ECONOMIC ANALYSES?

A. The present worth of revenue requirement (“PWRR”) for the alternative plans are presented in **Figure Williams-Direct-4**, which duplicates Figure EA-41 in the Economic Analysis Section of the narrative.

**FIGURE WILLIAMS-DIRECT-4
PWRR OF ALTERNATIVE PLANS
BASE LOAD, BASE FUEL, MID-CARBON SCENARIO**

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

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

A. Yes. The alternative plans were tested using base, high, and low economic growth scenarios as well as base, high, and low fuel and purchased power price forecasts. The mid-level carbon policy assumption was tested with high, low, and no carbon policy sensitivities. In addition, the Preferred Plan was subjected to a base load, base fuel, and mid-carbon policy scenario with the added ability to make off-system

sales. Analysis for these sensitivities over the 20-year planning period and the 26-year study period are provided in Figures EA-42 and EA-43 in the Economic Analysis Section of the narrative.

28. Q. PLEASE DISCUSS THE KEY FINDINGS OF THE PWRR ANALYSIS.

A. The key findings of the 20-year and study period PWRR analysis, including sensitivities, are summarized below.

- The Balanced Plan is the least cost of all alternative plans in all scenarios.
- The Renewable Plan is the second least cost plan in all scenarios.
- The Low Carbon Plan and No Open Position Plan are the two highest cost plans in all scenarios due to the aggressive buildouts to achieve the Plans' respective goals.
- The No Open Position Plan is the highest cost of the alternative plans in all scenarios and time horizons except the 26-year view of the high fuel scenario, in which the Low Carbon Plan is higher.
- The BLHFMC (High Fuel) scenario results in the highest PWRR and the BLLFMC (Low Fuel) scenario results in the lowest PWRR for all plans.

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

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

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

A. NERA conducted the present worth of societal costs (“PWSC”) analysis for the alternative cases. Environmental costs to the state associated with operating and maintaining a supply plan or demand-side plan must be quantified for air emissions, water and land use and the social cost of carbon for the plan. Environmental costs are defined by the Commission as “costs, wherever they may occur, that result from harm or risks of harm to the environment after the application of all mitigation measures required by existing environmental regulation or otherwise included in the resource plan.”⁴ The PWSC of a resource case is defined as the sum of the PWRR plus “environmental costs that are not internalized as private costs to the utility.”⁵ The PWSC of the Alternative Plans is presented in Figure NERA-9 in the Economic Analysis Section of the narrative.

The regulations also require the Companies to assess the “net economic benefits” of cases under certain circumstances.⁶ “Economic benefits” are often referred to as “economic impacts,” so that they are distinguished from other types of benefits. The net economic benefits include both the positive impacts of greater expenditures in Nevada and the negative impacts of higher electricity rates for consumers and businesses that generally accompany greater expenditures.

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

31. Q. PLEASE DESCRIBE THE CRITERIA FOR THE PREFERRED PLAN AND DISCUSS THE ALTERNATIVE PLANS RELATIVE TO THIS CRITERIA.

⁴ NAC 704.9359.

⁵ Nevada Administrative Code (“NAC”) Section 704.937(4).

⁶ See NAC 704.9357.

- A. The plans were evaluated based on their ability to meet the following criteria:
- Timely addition of appropriate amounts of new resources to address capacity and RPS needs due to load growth as well as loss of incremental planned resources;
 - Reduced exposure to the uncertain availability of market capacity, simultaneously advancing resource sufficiency as required for participation in WRAP or a future market or RTO;
 - Low overall cost;
 - Low societal impact; and
 - Targeting of the state's, Companies', and customers' decarbonization goals.

With the updated load forecast, the Companies have a growing need for resources for capacity, energy, and RPS contribution, which is also impacted by recent cancellations of Commission-approved projects. Substantial renewable and storage resource needs are addressed in all plans in the face of growing load and an aggressive RPS ramp up in the next several years. All alternative plans provide significant incremental capacity as well as RPS contribution with three PV/BESS projects. Two of the plans add near-term thermal resources as well. All plans address expected increased customer participation in the NGR program in addition to the state's RPS requirement.

This 2024 Joint IRP addresses steadily diminishing confidence in the availability of market capacity as it is impacted by changes in climate, weather, and resource variability across the region as supported by Mr. Atkins. This is achieved by adding capacity to the portfolio and targeting a smaller open position to reduce reliance on uncertain market capacity. As supported by Mr. Atkins, these efforts to reduce

reliance on market capacity simultaneously contribute to the resource sufficiency requirements of WRAP and expected requirements of a future regional market or RTO. While all four alternative plans reduce the near-term exposure to uncertain market capacity by adding new resources, the Balanced Plan mitigates this concern the most without creating excessively long capacity positions. The Renewable Plan has the highest open position in 2028 and 2029.

The Balanced Plan has the lowest PWRR of the alternative plans in the 20-year and 26-year study periods in all scenarios due in large part to its balance of renewable, storage, and cost-effective firm dispatchable resources and the moderate level of open position maintained in this plan. The Renewable Plan has the second lowest PWRR in both study periods in all scenarios – averaging 1 percent higher than the Balanced Plan in the 20-year planning period and 2.5 percent higher in the 26-year study period. Without near term CTs, the Renewable Plan has a larger buildout of BESS over the 26-year study period which leads to a significant increase in cost. The BESS, unlike CTs, is subject to a declining ELCC, a shorter asset life, and is energy limited, all of which drive an increased BESS buildout through the study period in this plan. The No Open Position and Low Carbon Plans have substantially higher PWRRs than the other two plans due to the need for more resources to meet the specific goals of these two plans. The Low Carbon Plan has the highest PWRR due to this plan’s need for a very large renewable and storage resource buildout in a very short span of time to meet the prescribed carbon dioxide target in 2030.

As determined in NERA’s analysis and supported by Dr. Harrison, the Balanced Plan has the lowest PWSC of the alternative plans over the 26-year study period. Compared to the Balanced Plan, the Renewable Plan and Low Carbon Plan have

1 slightly greater PWSC (about 2 percent and 5 percent, respectively), and the No
2 Open Position Plan has a somewhat greater PWSC (about 10 percent).

3
4 All plans presented in this 2024 Joint IRP add multiple PV/BESS projects to not
5 only achieve RPS compliance but to serve anticipated customer participation in the
6 NGR program. In addition, all plans target the Companies' proportionate
7 contribution to the state's 2050 clean energy goal. Due to the cancellation of
8 previously approved projects in this IRP and recent filings, all plans require use of
9 the banked PCs to ensure RPS compliance while addressing expected customer
10 participation in the NGR program in the early years. Despite varying additions of
11 thermal resources in the early years among the plans, all plans have similar carbon
12 dioxide emissions over the study period with the exception of the Low Carbon Plan,
13 which decarbonizes much more rapidly.

14
15 **32. Q. PLEASE DESCRIBE THE SELECTION OF THE PREFERRED AND**
16 **ALTERNATE PLANS.**

17 A. Based on the criteria and discussion presented in Q&A 31, the Companies selected
18 the Balanced Plan as the Preferred Plan and the Renewable Plan as the Alternate
19 Plan. The Balanced Plan employs a balanced approach to decarbonizing, adding
20 multiple PV/BESS projects and a thermal project, resulting in the lowest PWRR of
21 all plans across multiple time horizons. It reduces the open position dramatically
22 but cost-effectively. In this plan, the addition of two fast start peaking units at the
23 Valmy location eliminates the must-run requirement imposed on the Valmy
24 steamers – a requirement that would continue in perpetuity in the absence of these
25 peakers due to the forecasted northern load growth. It is also noteworthy that CTs
26 at this location do not compete for natural gas with Sierra's local gas distribution
27

company in Reno/Sparks. This plan adds the same renewable and storage resource projects as the other plans, as substantial renewable and storage resources are needed for RPS compliance in the face of growing load and an aggressive near-term RPS ramp up, and, to a lesser extent, to address the expected NGR program demand. This plan balances incremental capacity and RPS contribution with overall cost, economic net benefits, social costs, and other decarbonizing goals of the state, customers, and the Companies.

V. LONG-TERM AVOIDED COSTS

33. Q. DID THE COMPANIES CALCULATE LONG-TERM AVOIDED COSTS (“LTAC”) BASED ON THE PREFERRED PLAN PRESENTED IN THIS CASE?

A. Yes. Per NAC § 704.9492, the Companies have computed LTACs based on the Preferred Plan for purposes of determining LTAC rates. Under Nevada’s implementation of the Public Utility Regulatory Policies Act (“PURPA”), the Companies’ LTACs are calculated based on the mix of resources approved by the Commission through the integrated resource planning process. LTAC rates calculated based on the Companies approved IRP are to be offered to qualifying facilities (“QFs”) for blocks of capacity approved in the IRP. Estimates of LTACs are first filed in the utility’s IRP, based on the utility’s Preferred Plan. Here, the Companies have calculated estimated LTAC using is the method outlined below.

1. Determine the hourly marginal energy costs from the Preferred Plan.
2. Using the forecasted capacity cost described in the Load Forecast and Market Fundamentals volume, convert the forecasted capacity cost from

\$/kW-mo. to \$/MWh based on a 7x16 hours on-peak period for the months of July, August, and September.

3. Add the converted capacity costs in \$/MWh to the marginal energy costs for the 16 peak hours for every day of the month.
4. Average all of the hours in the month to determine the average monthly LTAC for each month of each year.

Figures EA-57 and EA-58 in the Economic Analysis section of the Supply Side narrative show the average monthly uncapped long-term avoided costs for each Company.

34. Q. PLEASE DESCRIBE THE LIMITS THE COMPANIES' HAVE CALCULATED FOR QUALIFYING FACILITY CONTRACTS.

A. The Companies propose that the LTAC rates be limited to a maximum of 76 MW at Nevada Power and 100 MW at Sierra of QF contracts and no more than a 25-year term. Nevada Power's average peak load growth in the Action Plan period, between 2025 to 2027, is estimated to be 76 MW per year. It is proposed that the qualifying facility tranche size for Nevada Power be set at this average Action Plan peak load growth of 76 MW. Sierra's average peak load growth in the Action Plan period, between 2025 and 2027, is projected to be 100 MW. Note that Sierra's forecasted peak load growth from 2025 to 2026 — approximately 20 MW — is impacted by the scheduled termination of the energy supply agreement with Liberty Utilities. Notwithstanding the loss of Liberty's load and resources in 2025, Sierra's proposed QF tranche size is proposed to be set at the average Action Plan peak load growth of 100 MW.

35. Q. **WHAT ARE THE NEXT STEPS IN THE LTAC PROCESS?**

A. Under NAC § 704.9496, the Commission must specifically address in its IRP order the utility's proposed estimated rates for LTAC, including the methodology and limits to be used going forward. Next, the regulation requires that within 60 days of the final determination in the utility's IRP, the utility must recalculate and refile LTAC that reflect the plan of action ultimately adopted by the Commission.⁷ Unless otherwise ordered by the Commission in its final determination regarding the utility's IRP, the recalculated rates reflecting LTAC also will reflect the same terms and be in the same format as the estimated rates originally filed by the utility in its IRP.⁸ The Companies will then follow the process of capping the LTAC rates outlined in NAC 704.9496.

VI. **INCORPORATION OF THE DRP INTO THE INTEGRATED PLANNING PROCESS**

36. Q. **HOW HAVE THE COMPANIES' INCORPORATED THE DRP INTO THE INTEGRATED PLANNING PROCESS?**

A. The integrated resource planning process continues to evolve as technologies and public policies emerge. In 2017, the Nevada State Legislature passed Senate Bill 146 ("SB146") requiring the Companies to incorporate the DRP into the IRP process. The Companies filed its first DRP as its first amendment to the 2018 IRP. The 2021 IRP was the first time the DRP has been incorporated into a full IRP filing. The IRP presents joint system level loads and resources needed to meet native load customer requirements over the long-term. The DRP addresses distribution level resource requirements and sets forth the plans and strategies to

⁷ NAC § 704.9496(2).

⁸ NAC § 704.9496(3).

meet near-term locational customer needs. Incorporating distribution resources will impact the need for the company to build new distribution facilities and impact the load on specific feeders within the system. Distribution resources can delay the need for such distribution facilities.

In this 2024 Joint IRP, as described in my Q&A 17 previously, certain existing and future DSM and DRP programs are modeled as supply resources rather than as load modifiers as they have been in past filings. As such, these resources are shown in the L&R tables and are modeled in PLEXOS. These resources, as modeled, are described in the Plan Development subsection of the Economic Analysis Section of the Supply Plan narrative. The modeled future DSM and DRP programs, determined early in the IRP planning process, differ from the proposed programs as described in the DSM and DRP Plans in this 2024 Joint IRP and supported by Ms. Steele and Ms. Rodriguez.

37. Q. HOW HAVE DISTRIBUTED ENERGY RESOURCES (“DER”) IMPACTED THE NEED FOR SUPPLY-SIDE RESOURCES IN THE RESOURCE PLANNING PROCESS?

A. As the proliferation of private owned generation and storage technologies increases, it is having an impact on the bulk power load forecasts and the potential need for supply side options. As described in the Load Forecast Volume of this IRP and supported by Mr. Pollard, the Company does adjust the forecast for the penetration of private owned generation, storage and electric vehicle infrastructure. For the first time in this IRP, certain DSM and DRP programs' impact on supply-side capacity can be seen by the planning capacity being served by these resources in the L&R tables.

VII. ECONOMIC ANALYSIS OF VARYING LEVELS OF DSM

38. Q. WHAT ECONOMIC ANALYSIS WAS CONDUCTED SURROUNDING VARIOUS LEVELS OF DSM IN THE IRP?

A. The Companies conducted additional economic analyses to assist in the determination of the rate impacts associated with differing levels of DSM programs. To this end, the Companies performed additional economic analyses on the Preferred Plan. One case assumed the Proposed DSM implementation, another case adopted an Enhanced DSM implementation, and the third case includes no DSM programs. Each of these cases assumed DSM implementation levels different from that assumed in the Preferred Plan. For the case with no DSM, the Companies created a new expansion plan in PLEXOS LT using a load forecast that excluded DSM programs entirely. In addition, the Companies conducted additional economic analysis to assist in the determination of the impact of achieving less than the planned levels of Demand Side Management pursuant to Directive 5 of the Order in Docket No. 23-06044.

In each of these additional cases, the DSM programs incorporated in the load forecast are adjusted. As such, each case required an updated load forecast. The DSM levels included in each analysis are shown in Figure EA-45 in the Economic Analysis Section of the narrative, along with reference to the associated load forecast. The load forecasts for these cases are supported by Mr. Pollard.

Only in the no DSM case were changes made to the DSM/DR programs modeled as supply resources. In this case, these programs were removed.

The Companies adjusted the L&R Table of the Preferred Plan to create the Proposed DSM, Enhanced DSM, and DSM Directive-5 cases because these cases required relatively minor adjustments to peak loads from the Preferred Plan. As mentioned previously, for the No DSM case, the Companies created a new expansion plan in PLEXOS LT using the appropriate load forecast and all the same assumptions from the Base Case.

An interpretation of the results, including the rate impact and revenue requirement impact, as applicable, can be found in the DSM Plan and is supported by the Companies' witnesses Chris Belcher and Sanem Sergici.

VIII. STUDY OF ILLUSTRATIVE CASE WITHOUT GREENLINK NEVADA

39. Q. WHAT ECONOMIC ANALYSIS WAS CONDUCTED REGARDING THE GREENLINK NEVADA PROJECTS?

A. As detailed in the Transmission Plan and supported by Mr. Lateef, there have been increases in the estimated total cost of the Greenlink Nevada ("Greenlink") transmission projects. The Companies maintain that, in the face of Sierra's rapidly growing loads, the Greenlink projects are necessary for continued joint system resource planning. The projects facilitate a reduced overall PRM requirement for NV Energy, systemwide access to the diverse renewable resources abundant in Nevada, and systemwide access to the benefits of WRAP and a future market or RTO.

The Companies created an illustrative case assuming Greenlink was not constructed. Together with the Preferred Plan, this illustrative case is intended to

demonstrate a portion of the value associated with the Greenlink projects for bundled retail customers.

Without Greenlink, Sierra will have very limited access to market purchases, including market capacity. Nevada Power will not have the same limitation. That is, the removal of the Greenlink projects will have a more significant impact on planned resources for Sierra than for Nevada Power. As Sierra will become increasingly transmission constrained over time if Greenlink is not built, the analysis of this scenario focuses largely on changes that impact Sierra.

The illustrative case was developed to provide an approximation, using simplifying assumptions, of the Companies' PWRR in a scenario that serves the forecasted demand in this 2024 Joint IRP in the absence of Greenlink. This illustrative case is a simplification, as a complete analysis would require many months to perform and would necessitate additional consultant engagement.

40. Q. PLEASE DESCRIBE THE CREATION OF THE NO GREENLINK ILLUSTRATIVE CASE.

A. The Companies engaged E3 to perform a Loss of Load Probability ("LOLP") analysis specific to Sierra without Greenlink, identifying the extent to which the Greenlink projects impact the Companies' ability to deliver resources from throughout the joint system to loads in Sierra in the future as well as the appropriate PRM for Sierra in 2028 in a scenario in which resource planning is bifurcated between Sierra and Nevada Power due to Sierra's growing transmission-constrained loads. The study results, including the conclusion that an estimated 18 percent UCAP PRM requirement would be needed to meet a 1-day-in-10-year

reliability standard for Sierra without Greenlink, are presented in Technical Appendix ECON-14 and sponsored by Mr. Schlag. Discussion of the limitations of the simplified application of this analysis are described by Mr. Schlag.

The Companies performed an assessment of need, identifying capacity needs of a system in which Sierra becomes increasingly transmission constrained as its load grows. The Companies applied the PRM from the Sierra Subsystem Resource Adequacy Analysis (“Sierra Subsystem Analysis”) to Sierra and retained the 2024 Joint IRP PRM for Nevada Power. As noted in the Sierra Subsystem Analysis, this likely understates the PRM requirement for Nevada Power in a scenario in which planning for the two systems is bifurcated, and thus understates the overall need. The ELCC values developed for the 2024 Joint IRP were used for both Companies in the absence of a full systemwide LOLP Study without Greenlink. It is noteworthy that the Sierra Subsystem Analysis identifies the risk that assessment of ELCC values for Sierra alone would tend to result in less value for the capacity contribution of BESS to Sierra compared to the joint system due to characteristics of Sierra’s system. The Companies conservatively allowed the open positions for Sierra to be substantially similar to the Preferred Plan in this illustrative case. If resource planning without Greenlink were required, further study would be needed to determine whether Sierra’s open positions should be reduced.

The Companies created a new PLEXOS LT analysis for the No Greenlink illustrative case using the base load forecast and the updated Sierra PRM with adjustments on constraints as described in the Economic Analysis Section of the Supply Side narrative. Proposed projects from the Preferred Plan were inserted to replace near-term expansion plan placeholders. The Libra PV/BESS project,

1 planned to interconnect at the junction of Greenlink North and Greenlink West, was
2 omitted as its size and timing could not be accommodated by Sierra customers and
3 the limited transmission between northern and southern Nevada in this scenario
4 made delivery of energy to Nevada Power questionable. Adjustments were made
5 to the remaining placeholders to allocate resources between Nevada Power and
6 Sierra, considering the capacity needs and RPS goals of the Companies while
7 respecting the very limited transmission capability between them. Named
8 placeholders from the Preferred Plan were also inserted to replace No Greenlink
9 expansion plan placeholders, with adjustments as described in the Economic
10 Analysis Section of the Supply Side narrative. Sierra's import capability modeled
11 in this No Greenlink case was modified to reflect no increase associated with
12 Greenlink.

13
14 In the IRP Preferred Plan, it is assumed that Greenlink will be available to
15 interconnect some amount of placeholder resources to the load centers.
16 Placeholders in excess of those that can be accommodated along Greenlink will be
17 built elsewhere in the state, likely requiring incremental transmission not yet
18 studied (approximately the same in all plans).As described in the Transmission
19 Section of the Supply Side narrative and supported by Mr. Pottey, if Greenlink is
20 not constructed, assuming the same quantity of resources would be interconnected
21 in the identified Renewable Resource Zones along Greenlink as in the Preferred
22 Plan, the construction of three alternate transmission lines would be required. The
23 No Greenlink case excludes the cost of Greenlink West and Greenlink North but
24 includes costs for the following three transmission segments to connect the same
25 amount of resources to the load centers in the absence of Greenlink: Amargosa to
26 NPC, Esmeralda to SPPC, and Lander to SPPC. It is generously assumed the
27

construction of these three alternate transmission lines could be completed in the same timeframes as the Greenlink projects to ensure the timely interconnection of future resources. While the No Greenlink case includes substantial incremental nameplate capacity relative to the Preferred Plan, no incremental transmission costs were applied to access these incremental resources. Instead, the conservative assumption was made that incremental resources could be strategically located to minimize incremental transmission requirements.

41. Q. PLEASE DESCRIBE YOUR OBSERVATIONS REGARDING THE NO GREENLINK ILLUSTRATIVE CASE.

A. The No Greenlink illustrative case results in approximately 7,900 MW more installed capacity over the study period than the Preferred Plan. In addition, due to the larger PRM for Sierra in this case and the fact that the Libra PV/BESS project is an inappropriate fit for the system without Greenlink, this illustrative case is reliant on substantial amounts of near-term placeholder resources as early as 2028. An incremental set of northern CTs are needed in 2029 that are not in the Preferred Plan.

The No Greenlink Illustrative case is observed to have significant unserved energy beginning in the early 2030's and generally growing over the years, as shown in Figure EA-52 in the Economic Analysis Section of the Supply Side narrative. This is likely due to the use of ELCC values developed for the 2024 Joint IRP in the absence of a full systemwide LOLP Study without Greenlink, as described previously. These ELCC values credit too much capacity to northern resources, especially BESS, in Sierra's smaller system, as discussed in the Sierra Subsystem

Analysis. The unserved energy can be observed to diminish somewhat when large amounts of diverse renewable resources (geothermal) are added in 2045.

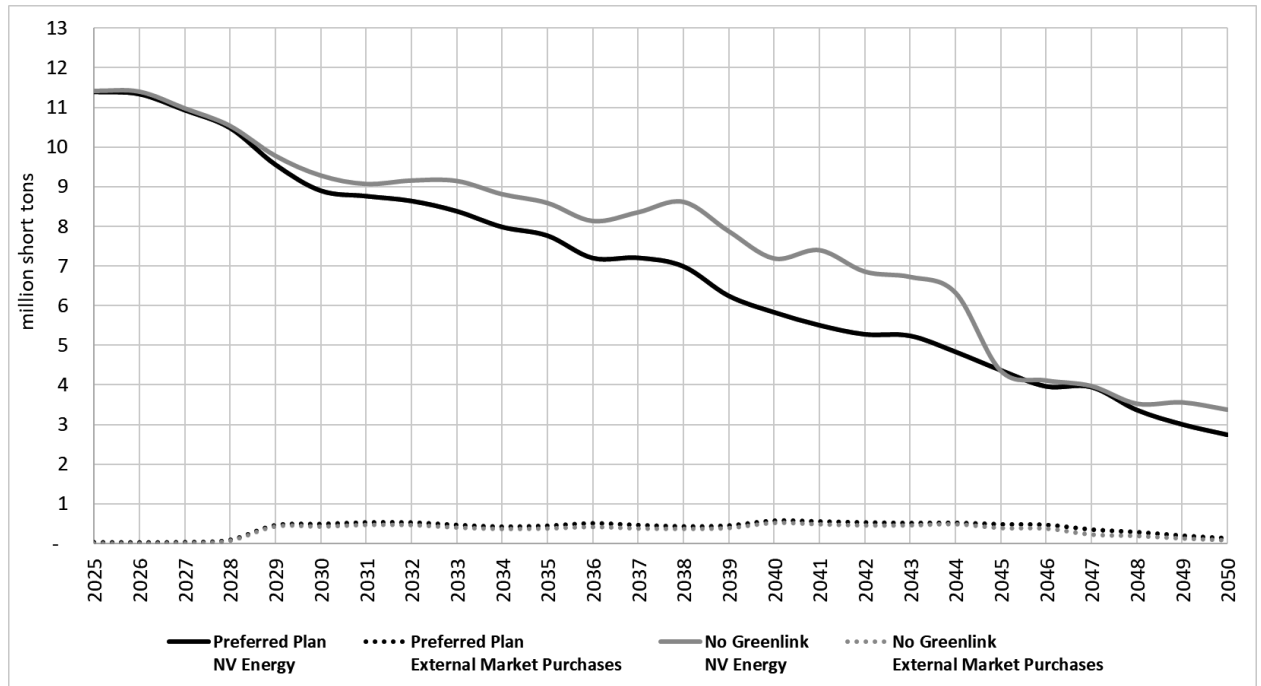
As evidenced by the unserved energy in this illustrative case, the simplifications applied in this case result in understatement of Sierra's reliability needs. As stated previously, this case was developed to provide an *approximation* of PWRR without Greenlink, as a complete analysis would require many months to perform and would necessitate additional consultant engagement. Such an analysis would be expected to result in identification of a requirement for significant additional capacity resources for Sierra relative to the No Greenlink illustrative case presented here.

As illustrated in Figure EA-53 in the Economic Analysis Section of the Supply Side narrative, without Greenlink, energy flows into Sierra are constrained (i.e., at their maximum) in substantially more hours over the study period than in the Preferred Plan and Sierra has a much narrower range of import/export capability.

Due to Sierra's limited import capability in the face of growing loads, the No Greenlink case has substantially more thermal generation within Sierra over the study period than in the Preferred Plan, while thermal generation within Nevada Power is lower. Carbon dioxide emissions are higher overall in the No Greenlink case relative to the Preferred Plan. **Figure Williams-Direct-5**, which duplicates Figure EA-55, illustrates that the increase in Sierra's emissions from its higher thermal unit operation more than offsets decreases in Nevada Power's emissions in this case, resulting in increased systemwide carbon dioxide emissions relative to the Preferred Plan. Emissions from market purchases, both included in the

systemwide total and presented separately in this figure, are largely unchanged between these cases.

**FIGURE WILLIAMS-DIRECT-5
NV ENERGY CARBON DIOXIDE EMISSIONS COMPARISON
NO GREENLINK CASE VERSUS PREFERRED PLAN**



42. Q. WHAT WERE THE RESULTS OF THE ECONOMIC ANALYSIS OF THE NO GREENLINK ILLUSTRATIVE CASE?

A. The results of the economic analysis of the No Greenlink case are presented alongside those for the Preferred Plan in **Figure Williams-Direct-6**, which duplicates Figure EA-57 in the Supply Side narrative

**FIGURE WILLIAMS-DIRECT-6
PWRR COMPARISON
PREFERRED PLAN VERSUS NO GREENLINK CASE**

	20 Year PWRR 2025-2044	26 Year PWRR 2025-2050	20 Year PWRR Change from Least Cost Case (million \$)	26 Year PWRR Change from Least Cost Case (million \$)	20 Year PWRR Rank Order	26 Year PWRR Rank Order
Preferred Plan	\$ 32,931	\$ 41,294	\$ -	\$ -	1	1
No Greenlink	\$ 33,042	\$ 42,126	\$ 111	\$ 831	2	2

43. Q. PLEASE DESCRIBE YOUR OBSERVATIONS REGARDING THE NO GREENLINK ILLUSTRATIVE CASE RELATIVE TO THE PREFERRED PLAN.

A. Overall, the No Greenlink illustrative case has increased production costs and decreased capital costs compared to the Preferred Plan, resulting in nearly equal (slightly higher) costs over the 20-year horizon. The No Greenlink illustrative case's 26-year PWRR, however, is approximately \$830 million higher than the 26-year PWRR of the Preferred Plan.

From this analysis, it can be observed that the scenario without Greenlink, while resulting in a similar PWRR in the 20-year view, understates the reliability needs for Sierra. In order for Sierra's customers to experience the same reliability to which they are accustomed, still more resources would be required within Sierra's system than those added in this illustrative case.

Irrespective of the underbuilt Sierra subsystem in this case, the cost benefit of Greenlink to bundled retail customers appears over the long term in this analysis. In the 26-year view, the beneficial impact of improved integration between the northern and southern systems on joint dispatch is evident in the lower PWRR of the Preferred Plan, driven by lower production costs. It is important to note that, as

a long-lived transmission project, Greenlink will continue to provide benefits well past the 26-year study period at minimal cost.

The Sierra Subsystem Analysis discusses the reliability benefits of a more integrated joint system as created by Greenlink. Further observations about the benefits of improved transmission interconnection, such as those provided by Greenlink, that are not fully captured in the illustrative economic analysis follow.

- Uncertainty and Extreme Events. Without Greenlink, the Sierra system is significantly more import-constrained, which limits its ability to adapt when extreme weather events or other system disturbances occur. One benefit of regional interconnections is the potential to receive support from neighboring systems that are not experiencing the same events. For example, if a northern Nevada winter storm severely limits the output or results in the outage of multiple northern resources, Sierra's ability to access southern Nevada resources via transmission can mitigate the effects of forced outages and derates associated with such weather events.

- System Diversity. Some of the greatest benefits of a well-connected transmission system result from system diversity. Customer demand in different regions materializes at different times, as illustrated in the differences between coincident and non-coincident peak loads between Sierra and Nevada Power. Also, renewable resources can perform differently in different regions. For example, solar resource performance is generally better in southern Nevada while traditional geothermal resources are much more plentiful in northern Nevada. Similarly, higher performing wind resources exist in Idaho and

Wyoming. Improved interconnection allows full access to a more diverse fleet of resources while allowing the resources to be located where they perform best.

- Access to External Markets and Resource Adequacy Programs. Improved interconnection to external markets unlocks more of the benefits associated with those markets. If a system is import-constrained, such as Sierra without Greenlink, it has limited ability to buy energy when needed. Significant import constraints limit the benefits of a resource adequacy program which allows for the pooling of resources for reliability. If a system cannot access outside resources during its time of need, it is not experiencing the full benefit of being part of a larger insurance pool of resources.

Significantly, at *higher* cost than the Preferred Plan, the No Greenlink illustrative case *underperforms* on Sierra's reliability needs and forgoes the described benefits that Greenlink provides to bundled retail customers.

In addition, further benefits of improved transmission interconnection provided by Greenlink are discussed by the Companies' witnesses Kiley Moore, Josh Langdon, and John Tsoukalis.

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

A. Yes.

EXHIBIT WILLIAMS-DIRECT-1

STATEMENT OF QUALIFICATIONS
KIMBERLY L. WILLIAMS
NEVADA POWER COMPANY d/b/a NV Energy
SIERRA PACIFIC POWER COMPANY d/b/a NV Energy
6226 W. Sahara Ave.
Las Vegas Nevada 89146
(702) 402-2184

EDUCATION

THE UNIVERSITY OF TEXAS AT AUSTIN – Austin, Texas
Bachelor of Science in Electrical Engineering

PROFESSIONAL EXPERIENCE

NV ENERGY – Las Vegas, Nevada (2005 to Present)

Director – Resource Planning and Analysis

- Oversight of the Resource Planning and Analysis team
- Development of the Companies' integrated resource plans and amendments, energy supply plans and updates, and gas information reports
- Oversight of production cost modeling and economic analysis related to intermediate and long-term planning activities of the Companies

Manager – Resource Planning

- Leads the preparation, filing, and discovery process of the Companies' Resource Planning filings
- Facilitates internal and external studies and evaluations in support of resource planning, business plans, and regulatory filings
- Coordinates with production cost modelers on assessment of needs and plan development for integrated resource plans

Manager – Environmental Services

- Led a team engaged in permitting and compliance for generation and transmission assets and ancillary facilities
- Led teams to identify, resolve, and report compliance concerns while building relationships with regulatory agencies
- Monitored regulatory developments, created compliance strategies, and provided guidance to management
- Performed due diligence on power plant acquisitions
- Developed environmental goals and methodologies for tracking sustainability initiatives

Staff Environmental Engineer

- Performed environmental permitting for power plants
- Supported construction and commissioning of combined cycle and simple cycle power plants
- Performed due diligence on power plant acquisitions

CHEVRON GLOBAL POWER GENERATION – Bakersfield, California (2000 to 2005)

Regulatory Compliance Coordinator

- Organized, directed, and coordinated environmental compliance and permitting activities for cogeneration facilities and a combined cycle power plant
- Managed environmental compliance during new simple cycle plant commissioning and conversion from simple cycle to combined cycle
- Tracked status of all permit requirements and reported to California Energy Commission monthly during construction of combined cycle plant

BERRY PETROLEUM COMPANY – Taft, California (1999 to 2000)

Environmental Advisor

- Ensured environmental compliance for all company oilfields and cogeneration plants in three California air districts
- Performed economic evaluation of environmental projects, proposed innovative solutions, and obtained permits
- Initiated and developed internal environmental and safety audits of company assets

ARCO OIL AND GAS COMPANY – Midland, Texas and Bakersfield, California (1990 to 1999)

Facilities/Construction Engineer

- Provided facility engineering and project management for several oil fields
- Supervised contract engineering and construction personnel

Engineering Development Program

- Provided diverse engineering support across departments throughout company

Summer Intern - Engineering

INDUSTRY ADVOCACY

COMBUSTION TURBINE OPERATIONS TECHNICAL FORUM (“CTOTF”)

- 2022-present: Growth and Development, Executive Vice Chair
- 2021-2022: Leadership Development Roundtable, Chair
- 2015-2021: Environmental Roundtable, Chair
- 2012-2014: Regulatory and Compliance Roundtable, Vice Chair

EXHIBIT WILLIAMS-DIRECT-2

NOTICE OF CONSUMER SESSION



January 5, 2024

Dear Valued Customer,

Customers of NV Energy are invited to a Consumer Session conducted at the Public Utilities Commission of Nevada (PUCN) to provide input on NV Energy's integrated resource plan to be held on January 10 at 6 p.m. The plan proposal will seek, among other requests, approval of resources to increase supply of electricity to its customers and limit the demand for electricity.

Click below for more details on the consumer session and how to participate.

[LEARN MORE](#)

Thank you,

The NV Energy team

This email was auto generated. Please do not reply.

Connect with us    

CONSUMER SESSION PRESENTATION





Meeting Guidelines



Purpose

This session is solely to discuss the 2024 Integrated Resource Plan ("IRP"). Please limit your comments to the 2024 IRP.



Comments

An opportunity for public comment will follow this presentation. Please use the sign in sheet and wait to be called on to ensure everyone can be heard.

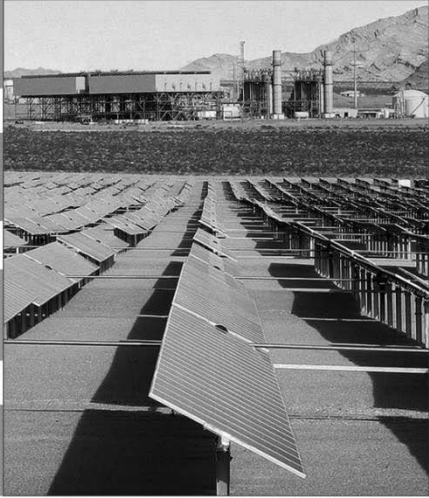


Please Note

The inputs and content of the 2024 IRP is under development and subject to change. This session is being held early in the process to receive public input.



Session Speakers

Janet Wells	Vice President Regulatory	
Ryan Atkins	Vice President Resource Optimization	
Kimberly Williams	Director Resource Planning & Analysis	
Marie Steele	Vice President Integrated Energy Services	



About Us

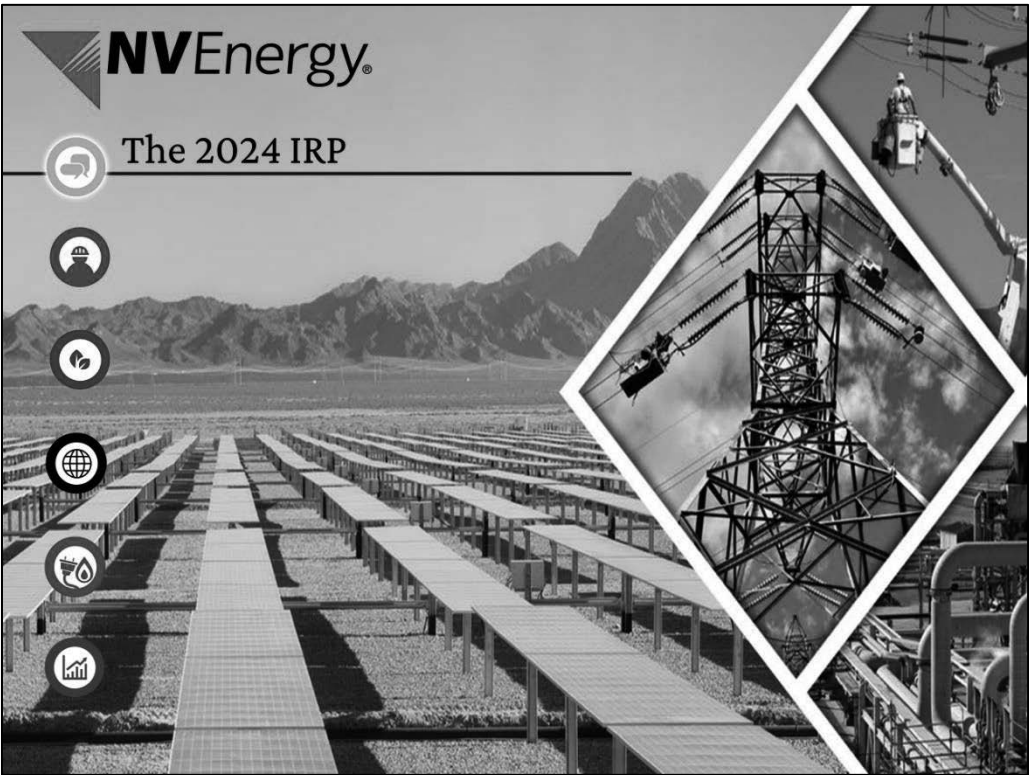
NV Energy's service area covers nearly 46,000 square miles throughout Nevada and about 90 percent of the state's population.

2,485 employees statewide

- Average tenure is 14 years.
- International Brotherhood of Electrical Workers
 - Local 396 in southern Nevada
 - Local 1245 in northern Nevada

Total payroll in 2022: \$322 million
Total paid taxes in 2022: \$267.6 million





The Integrated Resource Plan

Integrated Resource Plan

An Introduction

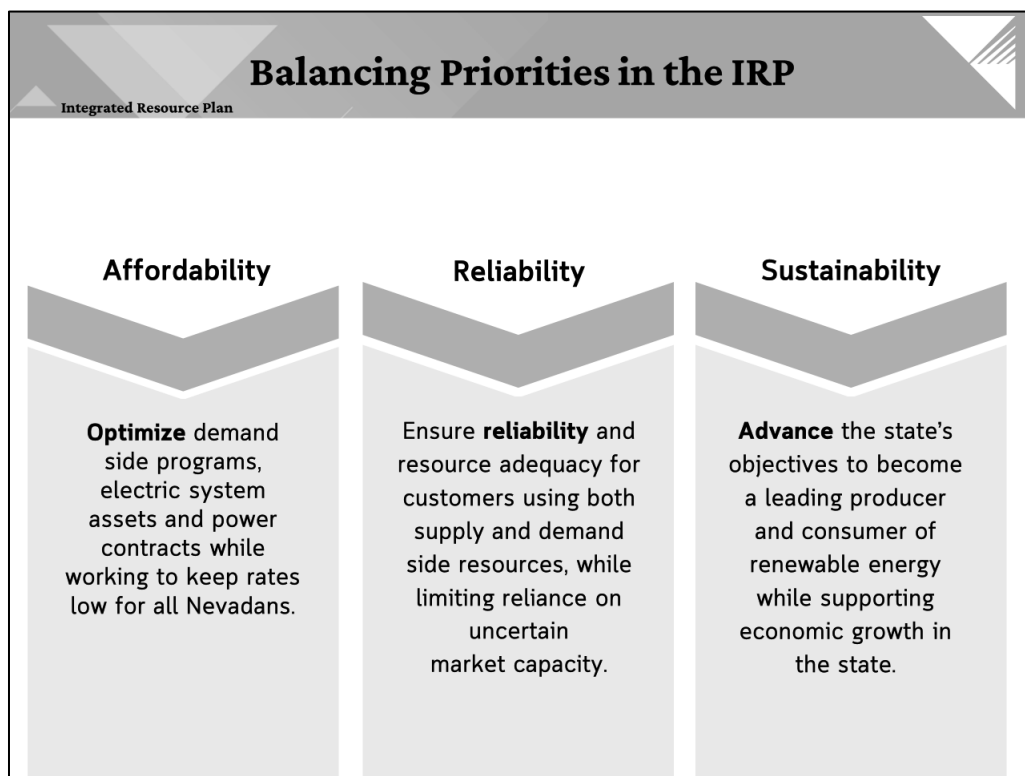
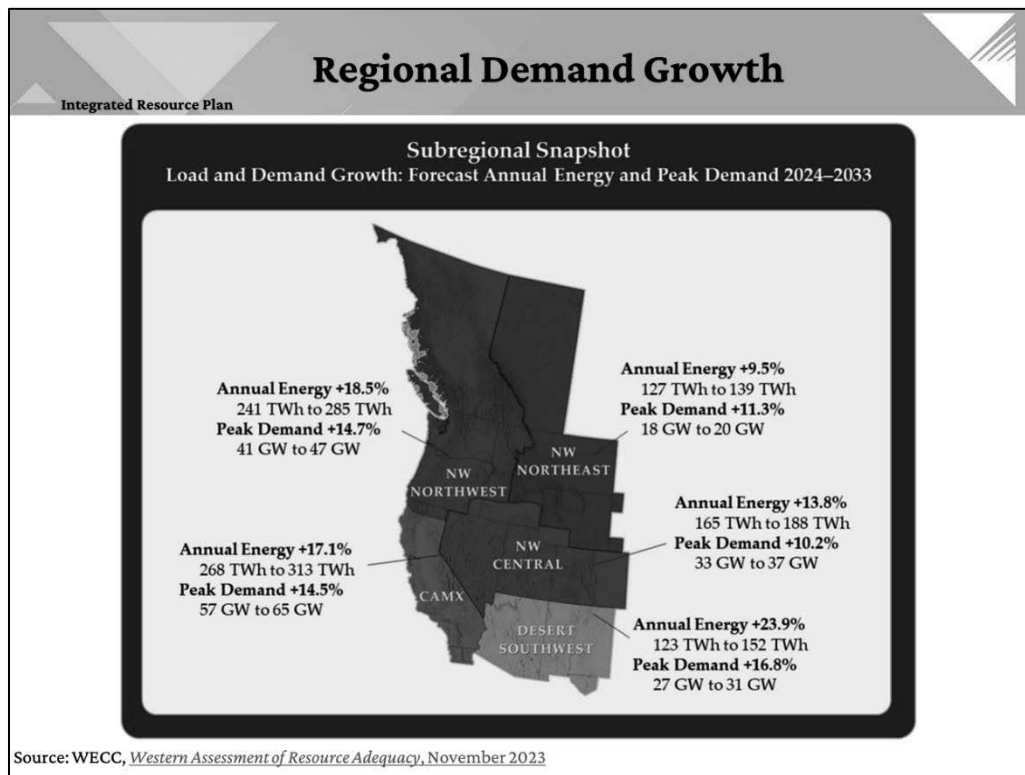
Integrated Resource Plans are comprehensive plans that analyze and evaluate a range of alternatives to meet future energy requirements through a combination of supply and demand side resources and the management of associated risks, such as fuel price volatility, economic and regulatory risk, impact on rates, and environmental compliance.

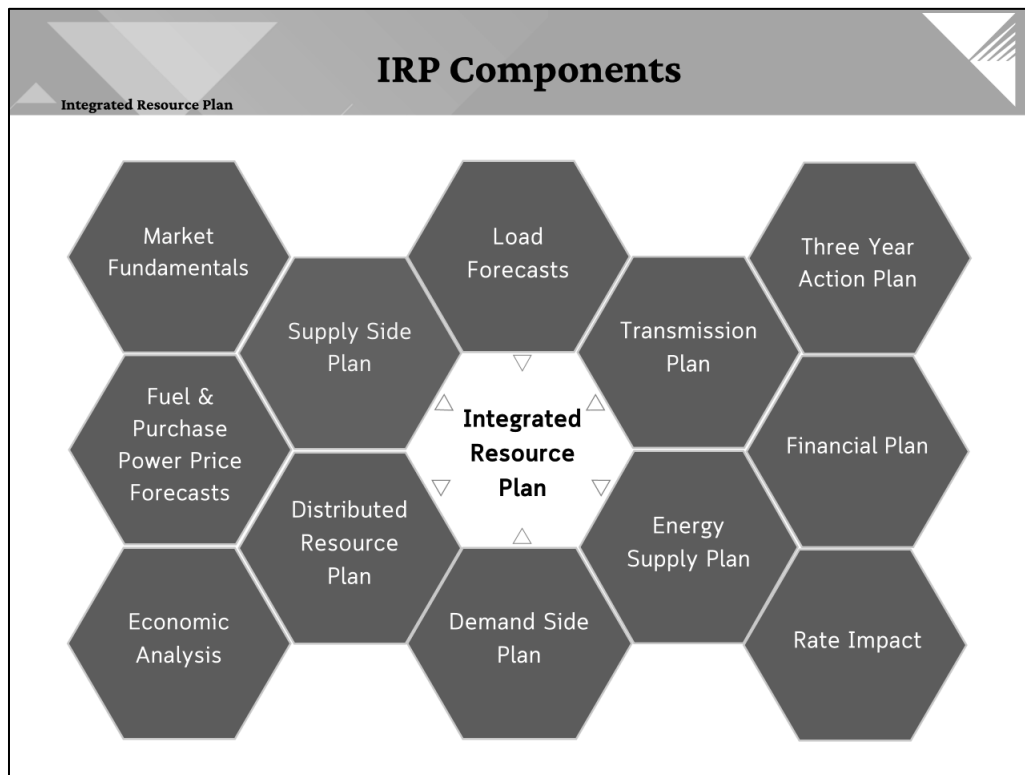
Regulatory Requirements

An IRP must be submitted at least once every three years (NRS 704.741) providing an integrated analysis over a 20-year planning horizon of:

- Load forecast
- Demand side plan
- Supply plan
- Financial plan
- Energy supply plan
- Distributed resources plan
- Three-year action plan

(NAC 704.9156)



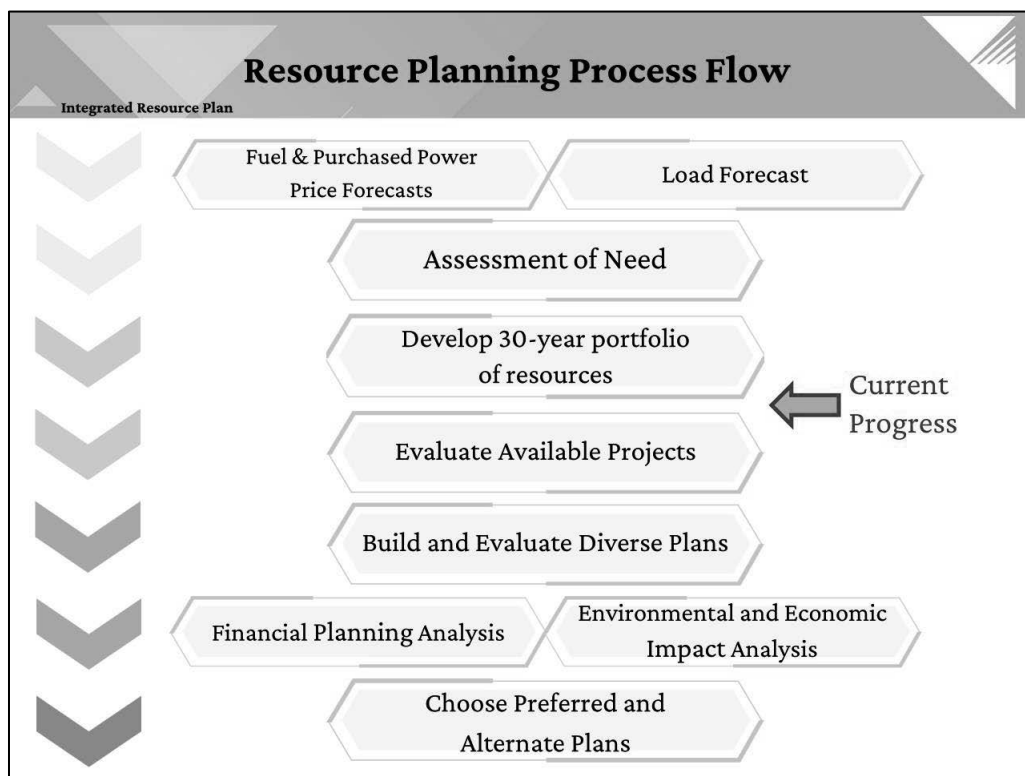
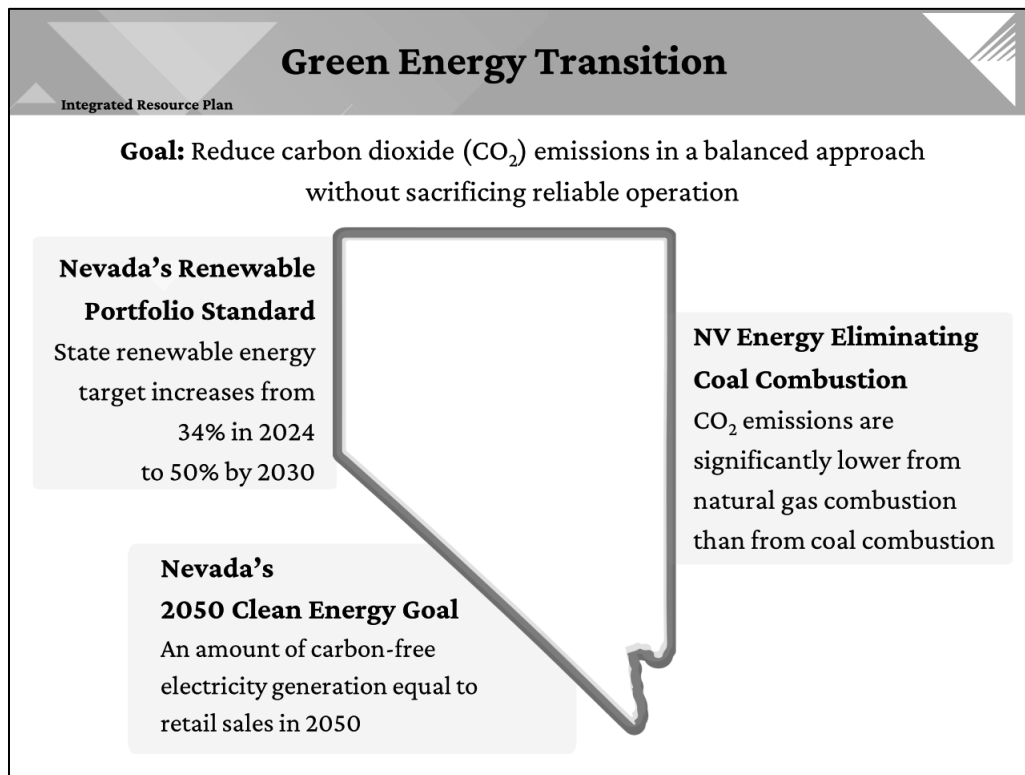


Key Legislated Changes

Integrated Resource Plan

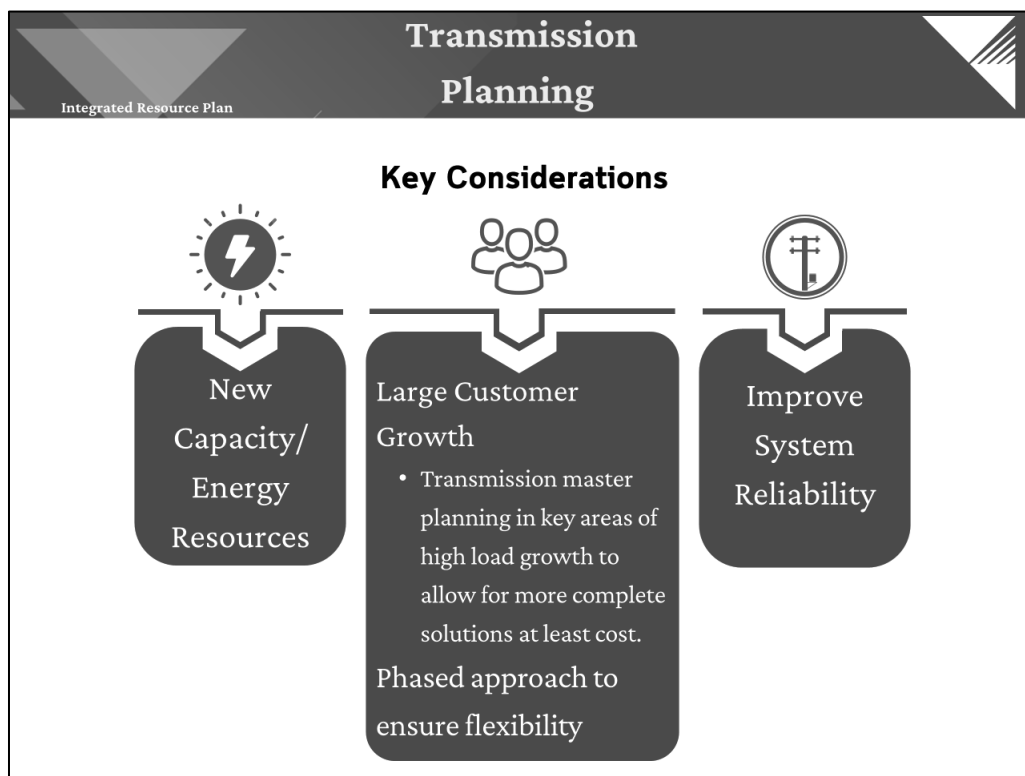
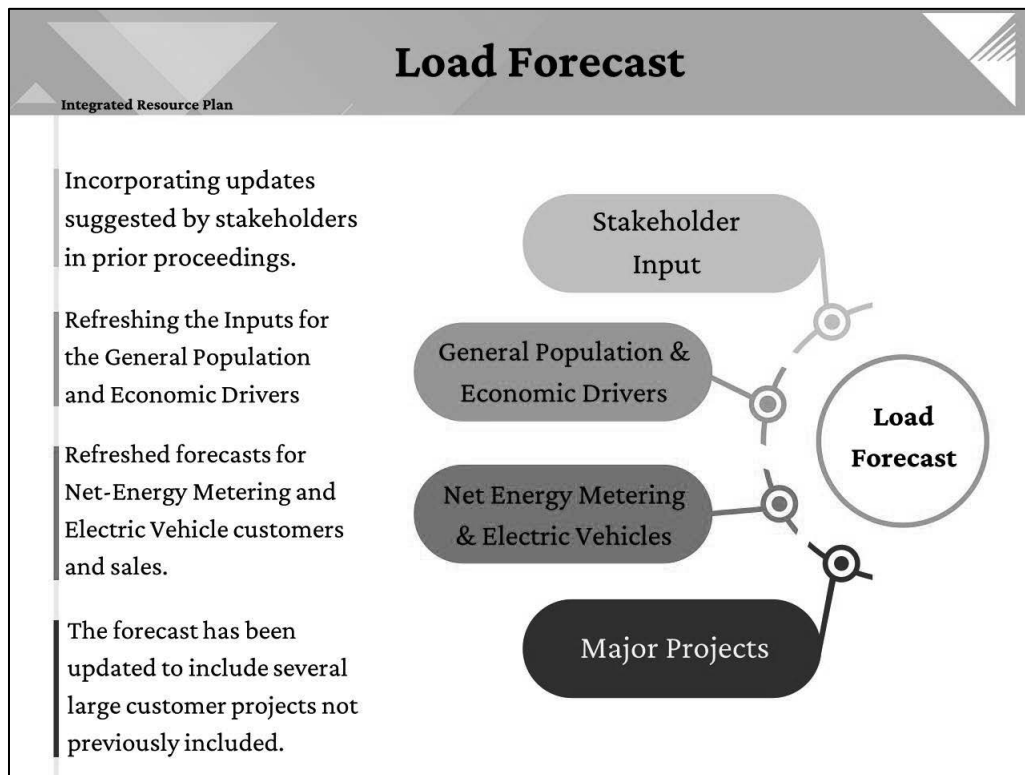
ASSEMBLY BILL 524

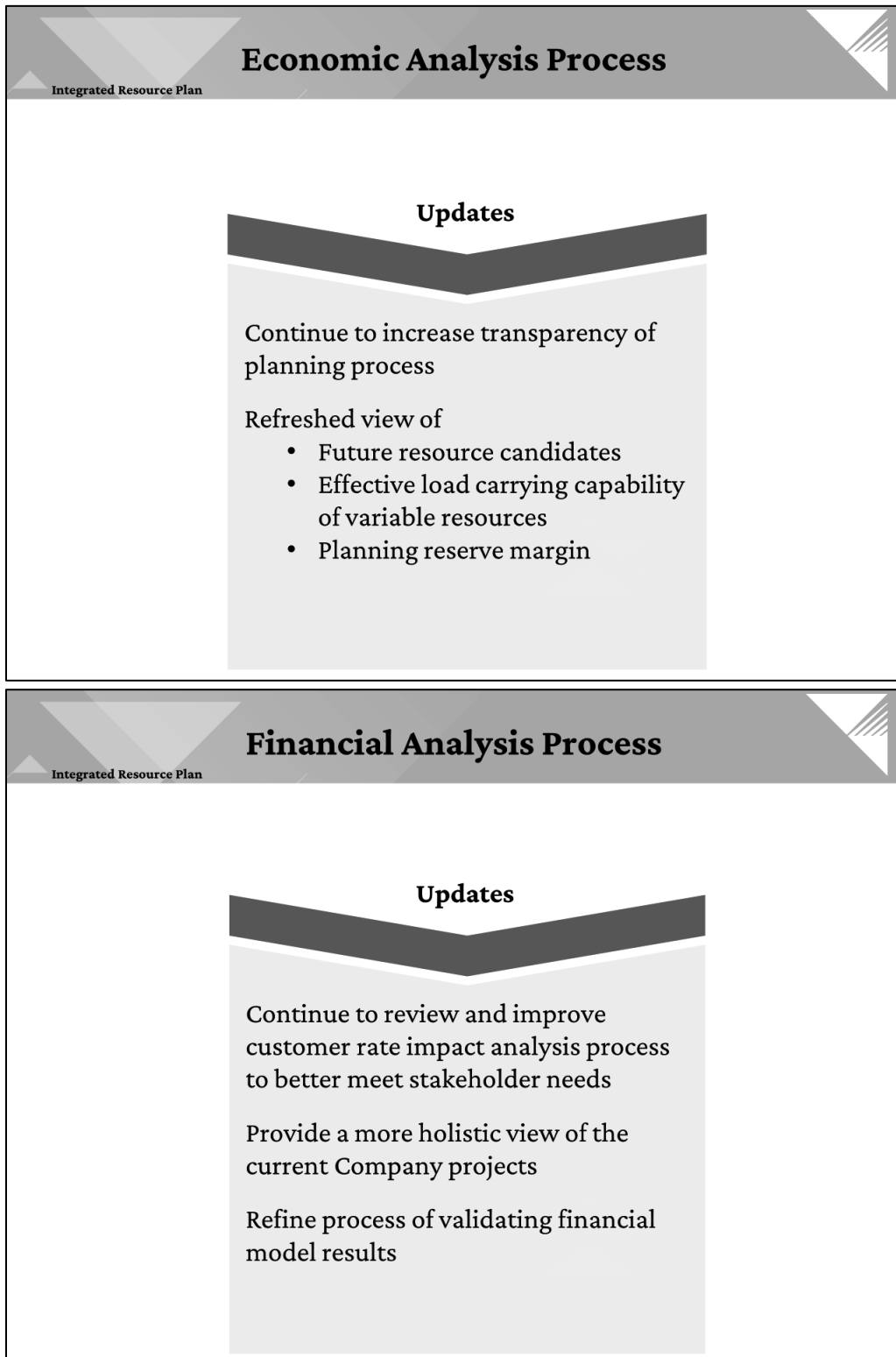
- An IRP may be filed more frequently than once every three years
- A consumer session will be held before filing an IRP or an amendment to an IRP
- The Commission will establish criteria to govern when an amendment may be filed to modify an approved plan
- The plan will include an additional scenario to evaluate reduced reliance on buying energy in the market and increasing utility-owned renewable and storage facilities
- For each scenario considered, additional impact evaluations are specified



Integrated Resource Plan	
Informing the 2024 IRP	
Key Inputs and Factors	
Updated Load Forecast	Includes new large customer load growth
Market Fundamentals and Price Forecasts	Established methodology
Coal Combustion	Anticipated to end by December 2025
Renewable Portfolio Standard	The portfolio standard requires generating, acquiring, or saving electricity from portfolio energy systems or efficiency measures the following amounts as a percentage of total retail sales: • Years 2024-2026: not less than 34% • Years 2027-2029: not less than 42% • Year 2030 on: not less than 50% (\$ NRS 704.7821)

Integrated Resource Plan	
Informing the 2024 IRP	
Key Inputs and Factors	
State's 2050 Clean Energy Goal	Target the company's proportionate contribution to this goal which strives for an amount of zero carbon generation equal to retail sales in 2050 (NRS 704.7820)
30-Year Resource Portfolio	Least-cost planning of diverse resources to meet customers' needs, informed by a variety of inputs
Renewable Projects	Available projects informed by 2023 RFP
Resource Adequacy	Future participation in Western Resource Adequacy Program
Energy Savings Targets	Customer programs driven by state policy









Distributed Resources Plan

Integrated Resource Plan

Analysis Improvement

DER Analytics Toolset and Potential Study

- DER Market Potential Study for all DER types
- DER Forecasting at the distribution level
- DER Valuation for use in DSM program cost-benefit analysis and Non-Wires Alternative Locational Net Benefit Analysis
- DSMore and LoadSEER toolset

Distributed Resources Plan Updates

Integrated Resource Plan

More inclusive Grid Needs Assessment encompassing all qualifying proposed and budgeted capital projects addressing grid constraints.

- Previously only included budgeted projects.

Transition to monthly Non-Wires Alternative analysis process

- Better ensures adequate lead time for analysis, decision-making, and implementation.

Proposed modernization and update of Rule 15

- Governs generation interconnection to the distribution system.





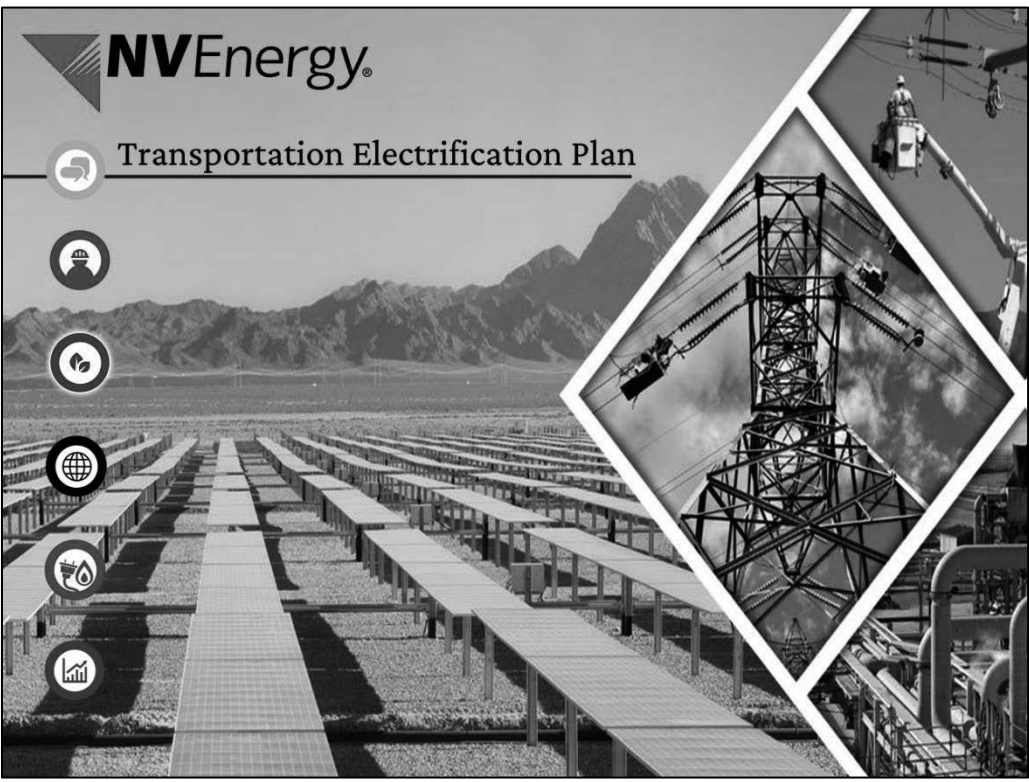


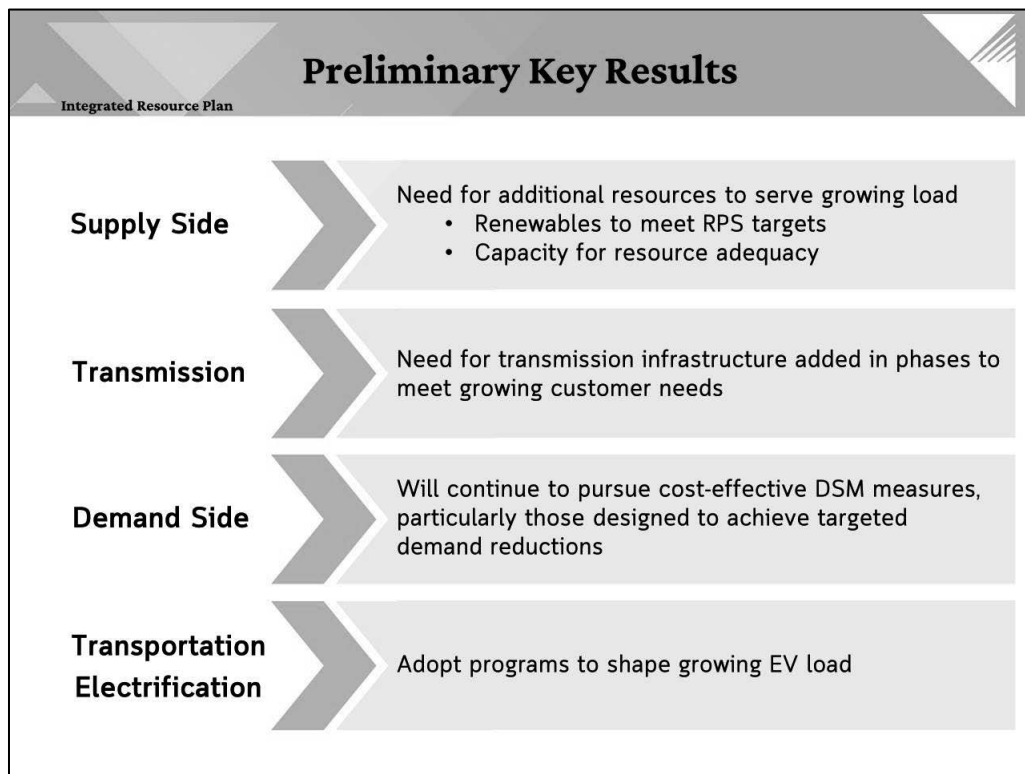
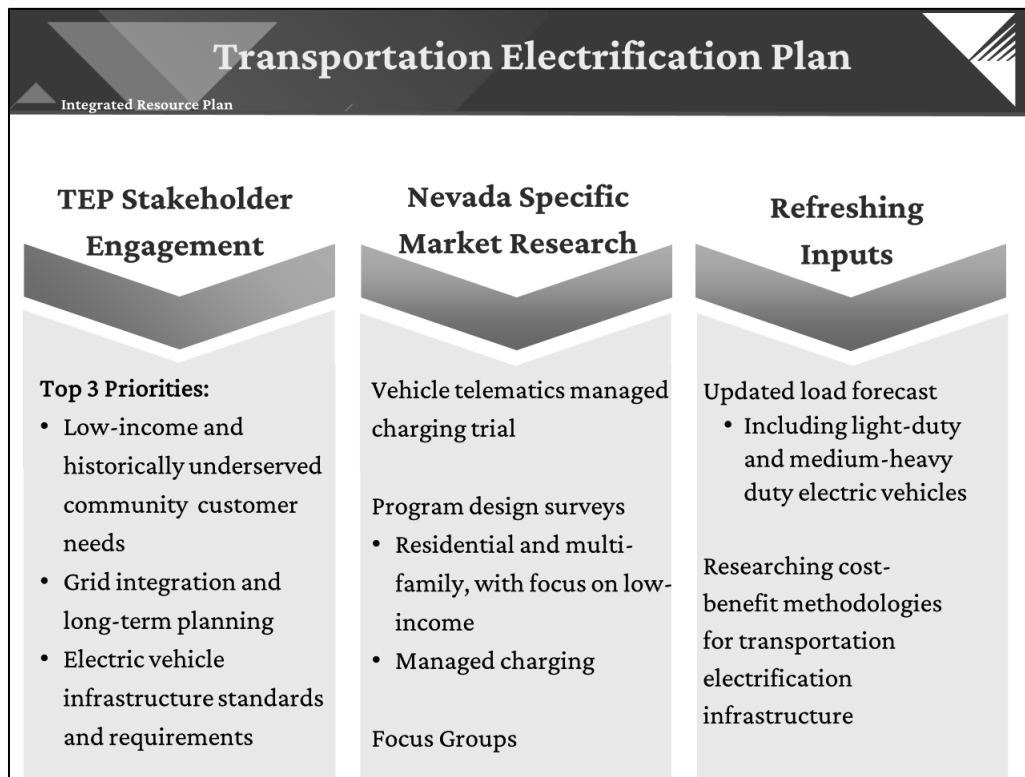
Transportation Electrification Plan











Thank you for your interest.

Comments?

Please use the sign in sheet and wait for your name to be called.

**To ensure everyone has the opportunity to speak,
comments will be limited to 3 minutes.**

CONSUMER SESSION: PUBLIC COMMENT SUMMARY

2024 IRP Consumer Session Meeting

January 10th, 2024, 6:00PM

PUBLIC COMMENT:

Las Vegas

- 1) (Resident)
 - a. Claims that every session of the legislature (except 2023) has induced NV energy to do a comprehensive cost benefit of Roof Top Solar
- 2) (Sierra Club)
 - a. Notes that he has a long history of advocating for clean energy.
 - b. Imperative this plan puts Nevada rate payers first, but there are three problems.
 - i. 1) More transparent process (need to know what the costs are for new generation)
 - ii. 2) Should not be building new fossil fuel power plants (aggressively exceed state goals)
 - iii. 3) Cost considerations are paramount which shows the need for transparency
 1. Green energy solutions provide the least costly energy and should be preferentially treated.
 2. Emphasis on grid enhanced technology, smart metering, and so forth
 - a. These measures are cost-effective.
- 3) (Resident)
 - a. Mentions the load issues in the summer season and that the voluntary curtailment of retail customers is unfair.
 - i. Concerned that businesses and hotels are not being asked to curtail which is an unfair ask for everyday residents.
 1. Claims that the MSG uses 100 TW/h annually.
 - b. Mentions its unfair that customers should reduce their energy consumptions during peak hours when businesses do not have to
 - c. *Question*: “Does NV energy make an analysis with these large customers when they’re acquiring the zoning to be built?”

4) (Resident)

- a. Claims that Nevada is the third sunniest state but ranks only sixth in solar adoptions.
 - i. Evidence: Forbes shows that California has a higher percentage of energy produced by solar.
- b. Topics she mentions:
 - i. Clean Energy solutions
 - ii. Community solar
 - iii. Valmy repower to natural gas is not a sustainable energy solution.
- c. “We lack policies that support affordable clean energy, our wildlife, and distributed energy resources.”

5) (Resident)

- a. Concerned about the outreach for underserved communities in Las Vegas.
- b. Asks the Company to better reach communities of color by providing 30 days’ notice that a consumer session is scheduled.
 - i. Notes that this will allow more historically underserved communities to make their voices heard.

6) (Resident)

- a. Concerned about how water, as a limited resource, is thought about and analyzed in the Integrated Resource Plan
 - i. Notes that he would like to see more about how water is analyzed in the IRP.
 - ii. Concerned about the endemic, endangered species in the state of Nevada that need water to survive.

7) (Nevada Conservation League)

- a. She is the Communicators Director for Nevada Conservation League
- b. Asks that the Company provides stable, affordable clean power for all Nevadans.
- c. Issues with the Consumer Session
 - i. Short Six Day Notice
 - ii. PUCN’s Building doors were not open at 6:00pm.
- d. Claims that the expansion of natural gas is responsible for wide swings in electric bills.
- e. The Company should address:
 - i. Nevada Businesses and customers should be able to benefit from low-cost clean energy.
 - ii. More transparent and comprehensive planning for additional clean energy

Carson City

8) (Resident)

- a. Mentions that he supports the transition to clean energy by utilizing nuclear energy.
 - i. One benefit is that it may create higher paying jobs with large scale reactors.
 - ii. "We should look to Georgia's Grid as a lesson."
- b. U.S Government is willing to support this transition.
 - i. Provides evidence that the Department of Energy understands how important nuclear energy can be for the future.

9) (Sierra Club)

- a. Mentions his opposition to burning fossil fuels for the health of citizens in the State.
- b. States that methane generation cannot be justified when the state is blessed with abundant geothermal and solar potential.

10) (Resident)

- a. Concerned with the increase in electric bills for people on a fixed income because the switch to clean energy sources may be too expensive.
- b. Mentions she is concerned about the lifespan of solar panels, how they're disposed of, and the negative impact that has on the planet.

11) (Resident)

- a. Asks the Company to provide more notification prior to a Consumer Session.
- b. Mentions he is a proponent and believer of Climate Change and wants the company to stop constructing gas power plants.
 - i. Cites the record-setting Summer of last year as enough proof we're heating the planet.
 - ii. Opposed to the Silverhawk Peaker Plant
- c. Mentions that isolated assets are something the Company is comfortable with when constructing new gas-fueled power plants.

12) (Resident)

- a. In support of switching to nuclear energy which he claims is the cleanest and most sustainable source.
- b. Suggests that the Company should invest in and lock in contracts for natural gas so that we have a share of the future of that supply.
- c. Believes the Company needs to have a diversified system that is 100% dependable and proven before moving into something else.
- d. Needs a cost-benefit analysis on Solar to see if the return on solar is it better over its lifetime vs. natural gas or nuclear.

13) (Resident)

- a. Opposed to NV energy building more natural gas plants for Rate Payers
- b. Required peaking power and capacity can be provided by renewable sources instead.

14) (Resident)

- a. Claims Nevada has the two fastest warming cities in the country.
- b. The Company and State needs to move towards more renewable energy instead of natural gas because of rising prices.

15) (Resident)

- a. Mentions he would like the cheapest electric service regardless of if the energy source is nuclear, solar, or something else.
- b. Concerned that the Company has not explored carbon capture technology and its leading to unnecessary pollution from natural gas.
 - i. Suggests putting the captured carbon into Yucca Mountain.

16) (Resident)

- a. Critical of Repower Valmy because we should be going to solar or wind.
- b. Critical of Berkshire Hathaway's purchase of NV Energy because of the 30-40% investment safety cushion Warren Buffett to maintain on all new company purchases.
 - i. He suggests that the margin that stakeholders should be reconsidered.

17) (Nevada Clinicians for Public Action)

- a. Mentions that 60% of NV Energy's provided energy comes from Fossil Fuels
 - i. Claims that Nevadans breathe the 5th most polluted air in the country because of fossil fuels.
- b. Notes that Nevada's RPS should be a floor and not a ceiling.
- c. She urges the PUCN to block the building of the Peaker plant and repower Valmy.

18) (Resident)

- a. Agrees with other participants about moving towards clean energy.
 - i. He says it is "hard to imagine (the Company) is considering building more fossil fuel plants when we know they're contributing to extreme weather consequences."

19) (Resident)

- a. Critical of the lack of notice for the Consumer Session and notes that the Company must get the word out earlier to reach the community.
- b. Concerned that the rising energy costs are crippling the community.

Phone Line

- 1) (Environmental Activist)
 - a. Proponent of expanding solar energy
 - i. Distributed Solar Energy through roof-top solar needs to be expanded.
 1. Believes the Company is afraid of making that change due to the reduction in profits.
 2. This resource needs to have a battery back-up at every building to solve “so many of our issues.”
 - a. Would serve as a virtual power plant.
 - b. Concerned about the state of the planet with 2023 being the hottest year on record.
 - c. Suggests the State move towards Alternative Ratemaking
- 2) (Resident, Retired Economist)
 - a. Expresses concern about new gas plants.
 - b. Critical that the IRP is not capturing the social costs of carbon.
 - i. Claims that there is a recent article finding the social cost of carbon being 185\$/Ton.
 - ii. “These damages are to the human economy (human beings) and many of those damages will be incurred by the poorest and most vulnerable in our society.”
 - c. *Question:* “Does the IRP deal with the changes that are afoot in the emissions from natural gas?”
 - i. Claims that the official government measures emissions from gas are underestimates because they don’t consider leaking methane.
 - ii. She would like to know if there is a sensitivity analysis.
- 3) (Western Resource Advocates)
 - a. Commenter claims that the Consumer Session presentation did not satisfy the requirements per law.
 - b. Notes that the Company gave some high-level updates, but didn’t provide enough information such as the comprehensive plan to join an RTO per the Commission.
 - c. “Without the opportunity to ask questions and engage, the requirements of the Consumer Session have not been met.”
- 4) (Unspecified)
 - a. In support of Nuclear Energy and believes the Company should be converting our fossil units to nuclear power because for its’ stability
- 5) (Unspecified)
 - a. Critical that there was not more notification for the Consumer Session.

- 6) (Unspecified)
 - a. Proponent of more aggressive renewable energy goals because “the planet doesn’t have that much time.”
 - b. Suggests that the company invest heavily into Roof Top Solar to install it in residential, industrial, and commercial structures.
 - i. Claims the benefits of this method are:
 - 1. Transmission grid is in place (no new permitting necessary)
 - 2. Lithium can be recycled and its capacity increases with recycling.
- 7) (Unspecified)
 - a. Suggests that the Company make these changes to the IRP:
 - i. Increase transparency in its planning process.
 - 1. Help stakeholders understand the process.
 - ii. Maximize energy efficiency and other demand side resources.
 - 1. Helps customers in the long term by reducing the need for more energy.
- 8) (Unspecified)
 - a. Critical that there were too many acronyms used during the presentation and it was not clear.
 - b. Not enough notification for the Consumer Session and not enough time between the next Stakeholder Briefing for the 2024 IRP.
 - c. Critical of the green energy transition, nuclear, and other industries not lowering their carbon emissions.
- 9) (CHISPA, League of Conservation)
 - a. Criticisms
 - i. Last minute notification that hurts underserved communities.
 - 1. Public commenter notes that the Spanish speaking community would have been completely left out otherwise.
 - ii. NV Energy must meet clean energy goals and stop using natural gas “for the health of our families.”

10) (Unspecified)

- a. States that the presentation left many unanswered questions.
 - i. Criticisms
 - 1. Nevadans are asked to voluntarily reduce power consumption.
 - 2. Questions if the Company would arbitrarily shut off electricity because it can't purchase enough power.
- b. Mentions that there are no new hydro possibilities and that nuclear and geothermal should be collocated together among various Rivers in Nevada.
- c. Critical of the Green Energy Transition
 - i. Believes that solar and wind are not reliable and do not work.
 - ii. Notes that we have no available low-cost large battery technology for a large metropolitan area.
 - iii. Claims that renewable energy is not cost effective when the myriad of tax incentives is included.
 - iv. Solar farms should be required to contribute to the Green Link transmission cost.
- d. Rate payers deserve an independent 3rd party contracted broke to negotiate prices on behalf of the consumers.
 - i. On its own, the company has no incentive to minimize fuel and purchase power cost.

11) (Unspecified)

- a. Critical of the solar Green Energy Transition for various reasons:
 - i. Believes that solar ruins the landscape and hardly produces any energy.
 - 1. Mentions that solar PV is 20% efficient at converting sunlight to energy and needs to be replaced within 20 years.
- b. He supports natural gas for the following reasons:
 - i. One of the cleanest burning gasses.
 - ii. Process that is used at some NV Energy plants causes the output of pollution to be minimal.
- c. Suggestions:
 - i. Nevada also is rich in geothermal activity, so we should be taking advantage of it.
 - ii. Nuclear is a proven technology.

END OF PUBLIC COMMENT

AFFIRMATION

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

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

Date: May 31, 2024


KIMBERLY WILLIAMS

NICOLAI SCHLAG

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

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

Prepared Direct Testimony of

Nicolai Schlag

I. INTRODUCTION

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

A. My name is Nicolai Schlag. My current position is Partner at Energy and Environmental Economics (“E3”). My business address is 44 Montgomery Street Suite 1500, San Francisco, California, 94104. I am filing testimony in support of Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, the “Companies” or “NV Energy”).

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

A. I have 15 years of experience working in the electric utility industry and have worked extensively on issues related to renewable integration and resource adequacy. I have worked for utilities and regulators throughout the Western Interconnection and North America to study various aspects of low carbon, highly

renewable electricity systems. My expertise is in utility resource planning, with a special emphasis on resource adequacy and reliability studies.

Before joining E3, I received a Master's degree in Civil and Environmental Engineering from Stanford University. I also hold a Bachelor of Science degree in Earth Systems, also from Stanford University.

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

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS PARTNER AT E3.

A. As a partner at E3, my responsibilities include the oversight of projects within E3's Resource Planning practice area. E3 works extensively with utilities and other clients throughout the country to support and engage in integrated resource planning ("IRP") processes. E3's work in this practice area typically focuses on utility long-term planning, where E3 provides support to its clients in identifying optimized and/or least-cost plans to meet long-term energy needs and environmental goals while maintaining reliability.

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

A. Yes. I have previously testified before the Commission on behalf of the Companies in Docket No. 20-07023, the Companies' Fourth Amendment to the 2018 Joint IRP; in Docket No. 21-0600, the Companies' 2021 Joint IRP; and in Docket No. 23-08015, the Companies' Fifth Amendment to the 2021 Joint IRP. In these proceedings, I led studies to evaluate the effective load carrying capability

1 (“ELCC”) of renewables and storage and to quantify the planning reserve margin
2 (“PRM”) necessary for the Companies to achieve a “one-day-in-ten-years”
3 standard of reliability and provided more general testimony on the state of resource
4 adequacy in the Western Interconnection and evolving best practices in planning. I
5 have also previously testified before the New Mexico Public Regulation
6 Commission and the Colorado Public Utilities Commission on behalf of utilities in
7 matters related to integrated resource planning and resource adequacy modeling.
8

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

10 A. My testimony serves two purposes. First, as an industry expert on the topic of
11 resource adequacy, I provide general background on how resource adequacy is
12 evolving and the implication that has for the Companies. This includes both
13 discussions regarding the Companies’ open position and the evolution of best
14 practices in resource adequacy planning. Second, the Companies requested that E3
15 provide several technical analyses as direct inputs into the 2024 IRP; my testimony
16 highlights the key elements of each of these three studies:

- 17 (1) A system resource adequacy study that provides updated planning reserve
18 margin (“PRM”) and effective load carrying capability (“ELCC”) values for
19 use in the Companies’ development of portfolios that meet a desired reliability
20 standard;
- 21 (2) A supplemental resource adequacy analysis of the Sierra subsystem that
22 examines how the south-to-north import limit within the joint system impacts
23 the local reliability with and without the Greenlink Nevada transmission
24 projects; and
- 25 (3) An analysis of the “uncertainty reserves” – operating reserves needed to provide
26 for sufficient flexibility at the day-ahead timeframe due to uncertainties in wind
27

and solar production – that serves as inputs to the Companies’ production cost modeling.

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

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

I am sponsoring the following Technical Appendices:

- ECON-12: 2024 Resource Adequacy Study
- ECON-13: Uncertainty Reserves
- ECON-14: Sierra Subsystem Resource Adequacy Analysis

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

A. No.

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

A. The remainder of my testimony is organized as follows:

- Section II provides a general overview of resource adequacy, how it is changing, and the implications that has for the Companies:
 - Section II.A provides background on resource adequacy and key trends that are reshaping the landscape across the Western Interconnection;
 - Section II.B discusses the implications of those trends for the Companies’ planning for its future open position; and
 - Section II.C introduces current best practices for resource adequacy planning.

- Section III provides key highlights of the 2024 Resource Adequacy Study used as the source of PRM and ELCC assumptions in the Companies’ planning:
 - Section III.A provides a description of the methodology and assumptions used in the study;
 - Section III.B discusses the key results of the study used by the Companies; and
 - Section III.C offers final conclusions and observations on the 2024 Resource Adequacy Study.
- Section IV provides an overview of the Sierra Subsystem Resource Adequacy Analysis.
- Section V describes the analysis E3 conducted to develop uncertainty reserves for inclusion in the Companies’ production cost modeling; and
- Section VI concludes my testimony.

II. RESOURCE ADEQUACY BACKGROUND

II.A. EVOLVING CONSIDERATIONS IN RESOURCE ADEQUACY

9. Q. WHAT IS “RESOURCE ADEQUACY?”

- A. “Resource adequacy” refers to the capability of a bulk electric power system to serve load across a broad range of weather and system operating conditions subject to a defined reliability standard. The resource adequacy of a system depends on the characteristics of load – magnitude, seasonal patterns, weather sensitivity, hourly patterns – as well as resources – size, dispatchability, outage rates, and other limitations on availability, such as the variable production of renewable resources. If the availability of resources is adequate to meet load across a wide range of

conditions and limit loss of load events to a reasonable level – where “reasonable” is defined by a reliability target – then a system is considered to have an adequate supply of resources. No electricity system is perfectly reliable; there is always some chance that generator failures and/or extreme weather conditions impacting supply and demand could coincide in a way that results in loss of load. In practice, utilities maintain an appropriate level of resource adequacy to ensure that such loss-of-load reliability events are rare.¹

10. Q. WHY IS ENSURING RESOURCE ADEQUACY IMPORTANT?

A. A reliable electric system is critical to the functioning of a modern society. Electricity outages are inconvenient to consumers who depend upon electricity to light and heat their homes and power their appliances, are costly to businesses who rely on electricity for commerce, and are potentially life-threatening to customers who rely on life-support systems powered by electricity. Utilities around the world plan their electricity systems to ensure that loss-of-load events, particularly the large, grid-wide events caused by an electricity supply shortfall, are exceedingly rare.

In planning their future systems, utilities must consider resource adequacy when making long-term investment, retirement, and contracting decisions. The construction time for new resources can range from several months to several years, depending on the type and quantity of a resource, among other factors. Therefore, utilities must plan years in advance to anticipate any long-term changes in loads or

¹ Resource adequacy does not consider potential reliability events on the distribution system, which can result from a variety of localized factors (e.g. high winds).

resources and procure additional resources as necessary to maintain an adequate supply of resources.

11. Q. HOW HAVE UTILITIES TRADITIONALLY PLANNED TO ENSURE RESOURCE ADEQUACY?

A. Historically, many utilities have focused their efforts on ensuring enough generation was available during peak demand periods. Utilities satisfied their reliability goals by maintaining a PRM, a margin of capacity above the expected peak demand to account for the possibility of unexpected extreme weather and generator outages. Historically, when the grid relied mostly on “firm” resources – resources that are generally available to produce power at full capacity for sustained periods, including nuclear, coal, and natural gas – this approach generally worked well. Because these types of firm resources can produce at full capacity when needed, a utility with sufficient capacity to meet its peak hour needs also generally had sufficient capacity during all other hours as well. In short, for most utilities, extreme load conditions (principally weather-driven) were the major driver of resource adequacy needs.

12. Q. WHAT CHANGES AND TRENDS HAVE THE GREATEST IMPACT ON UTILITIES’ EFFORTS TO PLAN FOR RESOURCE ADEQUACY?

A. Multiple factors have converged to create new challenges and additional complexities in resource adequacy planning for utilities across the industry. These include:

- Load growth: many utilities are projecting significant increases in load over the coming decade, driven by a combination of demographic changes, transportation and building electrification, and new large customers.

- Resource retirements: a substantial number of existing coal plants that have long served resource adequacy needs are approaching the ends of their lives, a trend that has been accelerated by state and federal clean energy policies and regulations.
- Significant growth of renewables and energy storage: state clean energy policies, economics, and customer preferences are all drivers behind the rapid deployment of wind, solar, and battery storage technologies across the region.
- Increasing extreme weather and climatic uncertainty: the shifting climate is contributing to increasing severity and frequency of extreme weather events.

The convergence of these factors has created a challenging and complex landscape in which utilities must plan for resource adequacy despite increased uncertainty and variability. In the Western Interconnection, load growth and resource retirements both contribute to the need to add new generation capacity to maintain reliability, while the transition to an electricity mix that includes much larger shares of variable and energy-limited resources has brought a new level of complexity to utility planning.

13. Q. CAN YOU PROVIDE EVIDENCE OF THE PRESENCE OF THESE TRENDS AND CHANGES?

A. Yes. I identify and discuss these trends as key challenges facing utilities in *Resource Adequacy in the Desert Southwest*,² a 2022 study conducted by E3 with funding from the five major utilities serving Arizona and New Mexico. The 2023

² E3, *Resource Adequacy in the Desert Southwest*, Feb. 2022, available at https://www.ethree.com/wp-content/uploads/2022/02/E3_SW_Resource_Adequacy_Final_Report_FINAL.pdf

1 *Western Assessment of Resource Adequacy*,³ published by the Western Electricity
2 Coordinating Council (“WECC”), notes the presence of the same trends, describing
3 how “[v]ariability remains the greatest risk to resource adequacy in the Western
4 Interconnection... Large, planned additions of variable resources, retirements of
5 traditional baseload resources, and extreme weather events are three of the main
6 drivers of resource and demand variability.” WECC’s assessment also notes the
7 recent acceleration of expected levels of load growth specifically:

8
9 “Demand is expected to increase by 16.8% over the next 10 years,
10 almost double the 9.6% growth reported in WECC’s 2022
11 assessment. The biggest driver of this increase is the expansion of
12 data centers, particularly in the Northwest. WECC sees no
13 indications of this risk abating and expects the risk to grow and
14 expand geographically as cloud computing and artificial intelligence
15 needs grow.”

16
17 These trends are further borne out in the narratives published in individual IRPs of
18 utilities across the region. For instance:

- 19 • Public Service Company of New Mexico’s (“PNM”) 2023 IRP⁴ observes
20 that “[r]eplacing retiring or expiring capacity, meeting concurrent load
21 growth, and reducing the carbon intensity of PNM’s portfolio will require
22 significant sustained addition of resources over the next two decades. The
23 scale of this transformation is unprecedented in PNM’s history...”

24
25
26 ³ Western Electricity Coordinating Council, *2023 Western Assessment of Resource Adequacy*, Nov. 2023, available at
<https://www.wecc.org/Administrative/2023%20Western%20Assessment%20of%20Resource%20Adequacy.pdf>.

27 ⁴ Public Service Company of New Mexico, *2023 Integrated Resource Plan*, Dec. 15, 2023, available at
<https://www.pnmforwardtogether.com/assets/uploads/PNM-2023-IRP-Report-corrected-2023-12-18.pdf>.

- Arizona Public Service’s (“APS”) 2023 IRP⁵ describes how “...massive growth within Arizona comes as our resource mix is poised to undergo significant changes. Our two remaining coal plants are quickly approaching the end of their operating lives.... Over this same period, we are investing heavily in affordable renewable and clean technologies...” and subsequently observes that “[a]s extreme weather has become the norm... our ability to maintain reliability is critical to the health and welfare of Arizona.”

14. Q. HOW DO INCREASING SHARES OF VARIABLE AND ENERGY-LIMITED RESOURCES MAKE PLANNING FOR RESOURCE ADEQUACY MORE COMPLEX?

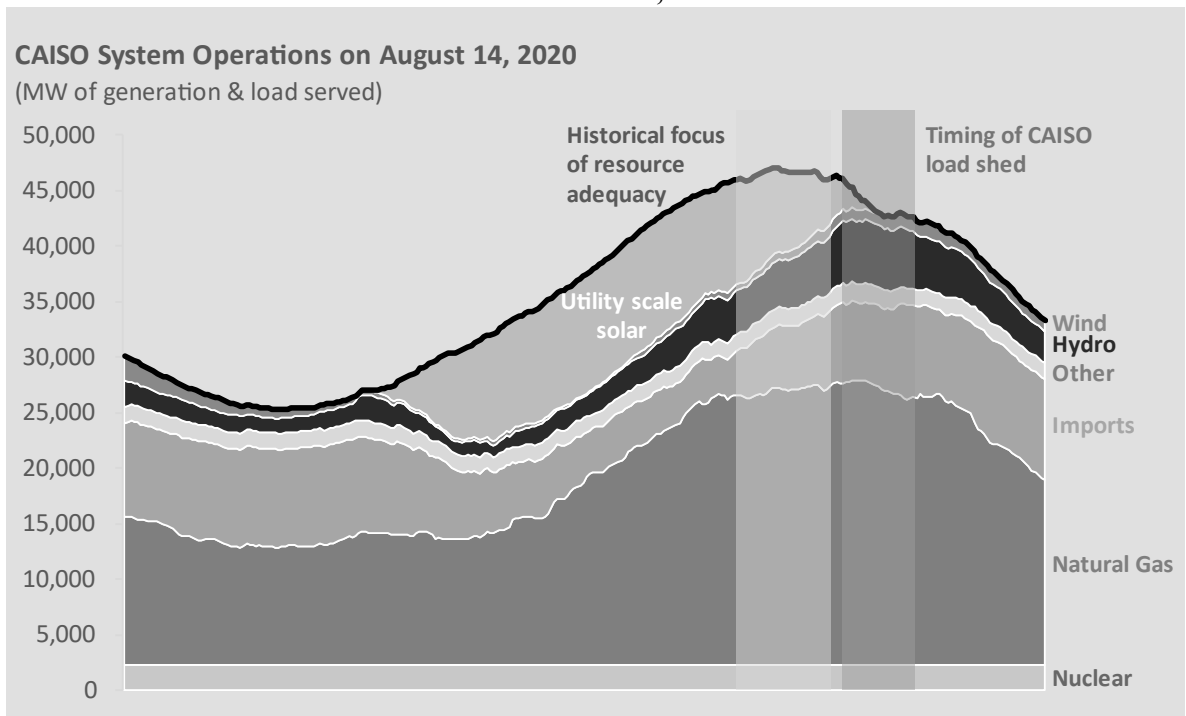
A. The transition to a system with higher penetrations of variable renewables (e.g. wind and solar) and energy-limited resources (e.g. energy storage) has introduced a new level of complexity to the objective of ensuring resource adequacy: increasing variability of supply. Unlike traditional “firm” resources (nuclear, coal, and natural gas) that can produce power at a constant level for sustained periods of time, variable renewables and energy-limited resources each have limitations on their ability to produce power when needed – renewables due to intermittency and storage as a function of state of charge.

Because the availability of these resources varies over time, their growing presence means that both demand and supply vary throughout the day, month, and year. As a result, reliability risks are no longer concentrated in peak periods – and in fact,

⁵ Arizona Public Service, *2023 Integrated Resource Plan*, Nov. 1, 2023, available at https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/APS_IRP_2023_PUBLIC.pdf?la=en&sc_lang=en&hash=DF34B49033ED43FF0217FC2F93A0BBE6_

can occur at different times of day (or at different times of year). California’s 2020 blackouts offer a real-world example of the nature of this dynamic, as the rotating outages instituted by the California Independent System Operator occurred during the evening “net peak” period after sunset – when demand net of wind and solar production was highest – rather than during the afternoon peak demand period. Figure NS-1 shows how the timing of the load shedding events in CAISO coincided with the evening net peak period, rather than the traditional afternoon peak period, a result of the high penetration of solar PV resources.

**FIGURE NS-1
INCIDENCE OF LOAD SHEDDING DURING “NET PEAK” PERIOD IN CAISO ON
AUGUST 14, 2020**



15. Q. WHAT IMPLICATIONS DO THESE TRENDS HAVE FOR THE COMPANIES?

A. These trends have two very direct implications for the Companies:

- Because the Companies have traditionally maintained a relatively large open position on the market, the rapid pace of change in the electric sector and the corresponding uncertainties directly impact the Companies. In Section II.B., I discuss the Companies' plans to reduce its open position in light of these changes.
- The compounding complexity resulting from increasing penetrations of variable and energy-limited resources requires continued adherence to best practices in resource adequacy planning. I discuss the current state of best practices in Section II.C.

II.B. IMPLICATIONS FOR THE COMPANIES' OPEN POSITION

16. Q. WHAT IS AN "OPEN POSITION?"

A. As it relates to resource adequacy, an "open position" refers to the portion of a utility's resource adequacy needs that are not met by resources under utility ownership or long-term contract. In order to provide reliable electric service, a utility must satisfy this portion of its needs with short-term market purchases.

17. Q. IN THE FIFTH AMENDMENT TO THE 2021 JOINT IRP, YOU TESTIFIED THAT THE COMPANIES' PLANS TO REDUCE ITS OPEN POSITION WERE REASONABLE IN LIGHT OF CONTEMPORANEOUS MARKET CONDITIONS. WHAT LED YOU TO THIS CONCLUSION?

A. I examined several pieces of evidence that led me to these conclusions:

- I reviewed multiple public studies, including E3's *Resource Adequacy in the Desert Southwest*, WECC's *2022 Western Assessment of Resource Adequacy*, the Northwest Power and Conservation Council's *Pacific Northwest Power*

1 *Supply Adequacy Assessment for 2027*, and the North American Electric
2 Reliability Council's *2023 Summer Reliability Assessment*⁶; each study
3 independently observed elevated reliability risks due to a tightening load-
4 resource balance in various parts of the Western Interconnection.

- 5 • I surveyed thirteen Western utilities and found that on an absolute basis, NV
6 Energy's planned open position for 2025 ranked second largest among utilities
7 surveyed, second only to PacifiCorp – meaning that relative to its peers, the
8 Companies' exposure to prevailing market conditions was relatively large.
- 9 • I examined the future plans of PacifiCorp and Puget Sound Energy – the two
10 other utilities with comparably large degrees of market reliance in absolute
11 terms at the time – and found that both utilities intended to significantly reduce
12 their reliance on the market over the coming five years to limit their risk
13 exposure as market conditions continue to tighten in the future.

14
15 These factors, coupled with observations regarding the nature of risks associated
16 with maintaining an open position when market conditions are relatively
17 constrained, were the basis for my observations at the time.

18
19 **18. Q. IS THERE ADDITIONAL EVIDENCE THAT SUPPORTS THIS**
20 **POSITION?**

21 A. At the time I filed direct testimony in the Fifth Amendment, WECC had not yet
22 issued its *2023 Western Assessment of Resource Adequacy*; that report has since
23 been published and underscores that circumstances in the West have not materially
24 changed since its 2022 report:

25
26
27 ⁶ NERC, *2023 Summer Reliability Assessment*, May 2023, available at
 https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf.

“High load growth, uncertainty in forecasting, and large amounts of new non-dispatchable resources are some of the factors that continue to challenge resource adequacy in the Western Interconnection. The recommendations and findings from WECC’s 2022 Western Assessment have not changed significantly. Resource adequacy risks continue to grow.”⁷

Additionally, prospective Western Resource Adequacy Program (“WRAP”) participants have experienced headwinds in the development of the very resources needed to meet the region’s future reliability needs. In a recent open letter addressed to stakeholders, the members of the Resource Adequacy Participant Committee (a group composed of 22 utilities and developers) write:

“...we have encountered significant new headwinds in addressing resource adequacy challenges. Supply chain issues and other challenges have slowed our ability to deliver and interconnect new resources. Regional peak load is now growing faster than previously expected, driven primarily by electrification and data center expansion. Extreme weather events have further challenged our assumptions and expectations of the quantity of resources needed to maintain reliable operations.”⁸

⁷ WECC, *2023 Western Assessment of Resource Adequacy*, Nov. 2023, available at <https://www.wecc.org/Administrative/2023%20Western%20Assessment%20of%20Resource%20Adequacy.pdf>

⁸ Members of the Resource Adequacy Participant Committee, *Open Letter to Stakeholders*, Apr. 22, 2024, available at https://www.westernpowerpool.org/private-media/documents/WRAP_RAPC_Participant_Letter_4_22_24_final.pdf

19. Q. IN LIGHT OF THS NEW EVIDENCE, HAS YOUR VIEW OF THE
COMPANIES' PLANS TO REDUCE ITS OPEN POSITION CHANGED
SINCE YOUR PREVIOUS TESTIMONY?

A. No. In my view, the Companies' continued efforts to reduce its open position
remains justified by the changing conditions of the western wholesale market and
the risks associated with large degree of reliance on the market as the regional load-
resource balance continues to tighten.

II.C. CURRENT BEST PRACTICES IN RESOURCE ADEQUACY PLANNING

20. Q. YOU HAVE PREVIOUSLY PROVIDED TESTIMONY DESCRIBING
CURRENT BEST PRACTICES IN RESOURCE ADEQUACY PLANNING.
CAN YOU PLEASE REITERATE THOSE BEST PRACTICES?

A. In the Fifth Amendment to the 2021 Joint IRP, I provided a description of best
practices that remains applicable today: current best practices for modeling
resource adequacy use Loss of Load Probability ("LOLP") modeling techniques
together with a PRM capacity accounting framework to ensure sufficient resources
are available when needed. The key steps in this framework include:

1. Establish a statistical standard for resource adequacy, e.g., 1 day in 10 years;
2. Use LOLP modeling to determine the PRM requirement needed to meet this
standard;
3. Apply an ELCC methodology for capacity accreditation, derived directly from
the same LOLP model, to determine how much existing and prospective new
resources can contribute to the PRM requirement on an equivalent, apples-to-
apples basis; and

4. Regularly update this analysis to account for changes in load shapes and the resource portfolio over time and to incorporate additional information that becomes available in the future.

21. Q. PLEASE DESCRIBE LOLP MODELING IN MORE DETAIL.

A. LOLP models simulate the availability of a portfolio of generation resources to meet system needs across a broad range of conditions. Most LOLP models use Monte Carlo simulation techniques to compare the available supply of generation resources with demand for electricity on a time-sequential, hourly basis; accounting for natural variations in load, renewable production, forced outages, and the dispatch of energy-limited resources. To characterize the probability of very rare reliability events robustly, the Monte Carlo approach is typically used to simulate system conditions for a single year repeated over hundreds to thousands of “draws,” where each draw represents a unique combination of weather conditions (and associated load and renewable profiles) and power plant outages. This approach ensures that rare extreme tail events that would be unlikely to occur in a typical year but that contribute to reliability risks are representatively sampled. This type of analysis is widely accepted as foundational to robust resource adequacy planning; for instance, the Energy Systems Integration Group’s (“ESIG”) *Redefining Resource Adequacy for Modern Power Systems* describes:

“Modeling sequential grid operations is critical to capture the whole picture: the variability of wind and solar resources along with the energy limitations of storage and load flexibility. Chronological stochastic analysis is thus increasingly important, simulating a full hour-to-hour dispatch of the system’s resources for an entire year of

operation across many different weather patterns, load profiles, and random outage draws.”⁹

LOLP models produce multiple useful metrics that describe the potential timing, magnitude, frequency, and duration of reliability events, including:

- **Loss of Load Expectation (“LOLE”)**: the expected number of days per year with a loss of load event;
- **Loss of Load Hours (“LOLH”)**: the expected number of hours per year with a loss of load event;
- **Expected unserved energy (“EUE”)**: the expected quantity of energy (MWh) per year that is unserved due to loss of load.

The results of LOLP models can also be used to determine both PRM requirements and ELCC values for different types of generation resources.

22. Q. HOW CAN AN LOLP MODEL BE USED TO CALCULATE A PRM REQUIREMENT?

A. Determining a PRM requirement corresponding to a specified reliability standard requires an iterative process using an LOLP model. First, the LOLP model is used to evaluate the reliability of a system given a demand forecast and a portfolio of resources. The results of this simulation are used to make adjustments to the system that bring it into alignment with the standard: if the system fails to meet the desired standard (i.e. is less reliable), additional resources, often in the form of generic

⁹ ESIG, *Redefining Resource Adequacy for Modern Power Systems*, 2021, available at <https://www.esig.energy/wp-content/uploads/2022/12/ESIG-Redefining-Resource-Adequacy-2021-b.pdf>

“perfect capacity”¹⁰ are added to the system; if the system is more reliable than the desired target, perfect capacity is removed (or, alternatively, flat load is added). These adjustments continue iteratively until the system, including these tuning adjustments, produces a result that is aligned with the desired standard. Once that result has been achieved, the corresponding PRM requirement can be determined by comparing the sum of “accredited capacity” – each resource’s contribution to the PRM requirement – across all resources in the portfolio, including the tuning adjustments, against the system’s peak demand.

23. Q. IS THERE A SPECIFIC RESOURCE ADEQUACY STANDARD THAT UTILITIES MUST USE WHEN DEVELOPING THEIR PRM REQUIREMENT?

A. No. There is no single mandatory or voluntary national standard for resource adequacy; however, many utilities in North America rely on a “1-day-in-10-year” standard to determine whether their systems have an adequate supply of resources. A current list of standards used by utilities and grid operators is provided in Table NS-1.

¹⁰ “Perfect capacity” describes a hypothetical resource that is available at full capacity all hours of the year. While no resource is truly perfect, this hypothetical resource provides a useful benchmark against which to measure the capacity contributions of real-world resources.

**TABLE NS-1
RELIABILITY STANDARDS CURRENTLY USED BY VARIOUS UTILITIES AND
RESOURCE ADEQUACY PROGRAMS**

Category	Utility/Jurisdiction	Metric	Current Standard
Western Utilities	Arizona Public Service Co	LOLE	0.1 days per year
	Avista Corporation	aLOLP ¹	5% per year
	Black Hills Energy	LOLE	0.1 days per year
	El Paso Electric Co ²	LOLE	0.2 days per year
	Idaho Power Company	LOLE	0.1 days per year
	NV Energy	LOLE	0.1 days per year
	Portland General Electric	LOLH	2.4 hours per year
	Public Service Company of Colorado	LOLE	0.1 days per year
	Public Service Company of New Mexico	LOLE	0.1 days per year
	Puget Sound Energy	aLOLP ¹	5% per year
	Salt River Project	LOLH	2.4 hours per year
	Tucson Electric Co ³	PRM	15%
Other Utilities	Dominion Energy South Carolina	LOLE	0.1 days per year
	Duke Energy Carolinas	LOLE	0.1 days per year
	Duke Energy Progress	LOLE	0.1 days per year
	Florida Power & Light	LOLE	0.1 days per year
	Georgia Power Co	LOLE	0.1 days per year
	Nova Scotia Power, Inc.	LOLE	0.1 days per year
RTOs & Resource Adequacy Programs	California Public Utilities Commission	LOLE	0.1 days per year
	ISO New England	LOLE	0.1 days per year
	Midcontinent ISO	LOLE	0.1 days per year
	New York ISO	LOLE	0.1 days per year
	PJM	LOLE	0.1 days per year
	Southwest Power Pool	LOLE	0.1 days per year
	Western Resource Adequacy Program ⁴	LOLE	0.1 days per year

Table Notes

1. Annual loss of load probability (aLOLP) is a metric used predominantly in the Northwest that measures the probability of at least one reliability event occurring over the course of the year.
2. El Paso Electric's 2021 IRP assumed a transition from a standard of 0.2 days per year to 0.1 days per year by 2030
3. TEP's current planning reserve margin is not directly tied to a probabilistic resource adequacy requirement
4. While the Western Resource Adequacy Program is still in conceptual phases of implementation, its sponsors have indicated an intent to rely on a standard of 0.1 days per year

24. Q. PLEASE DEFINE "EFFECTIVE LOAD CARRYING CAPABILITY" ("ELCC").

A. ELCC is a method of capacity accreditation¹¹ that is derived directly from LOLP modeling. It is considered to be the most robust measure of a resource's

¹¹ "Capacity accreditation" refers to the process of assigning capacity credits to individual resources for the purposes of measuring their contribution towards the PRM requirement.

contribution to a utility’s reliability standard, and is defined as the quantity of “perfect” capacity that could be replaced or avoided by a resource while providing equivalent system reliability. For example, if a 100 MW resource has an ELCC of 50 MW, that means that that this resource could displace the need for 50 MW of perfect capacity with no impact on system reliability. The ELCC of a resource can also be expressed in percentage terms by dividing by the nameplate capacity; in this example, the ELCC of the resource would be 50 percent.

For utility planning, two distinct applications of ELCC are useful: (1) the “portfolio ELCC,” which represents the aggregate capacity contribution of a group of resources, and (2) the “marginal ELCC,” which represents the capacity contribution provided by an addition of a specific resource or technology to an underlying portfolio. The former provides a means to measure the total capacity contribution of a utility’s existing portfolio towards its PRM requirement, while the latter is the most useful measure when evaluating how the addition of new resources would impact a utility’s load-resource balance. A resource’s marginal ELCC is not an intrinsic static value but depends upon the characteristics of the electricity system (both loads and resources) to which it is added.

25. Q. HOW CAN AN LOLP MODEL BE USED TO CALCULATE THE ELCC OF A SPECIFIC RESOURCE?

A. The approach used to determine a resource’s ELCC in an LOLP model closely parallels the process through which the PRM requirement itself is determined. The ELCC methodology requires iterative simulation to determine the quantity of perfect capacity that provides the same value as a specific resource, involving the following steps:

- Adjust existing system to target reliability standard: the analysis begins with a representation of the system at its target standard (e.g. 0.1 days per year), meaning that there is sufficient capacity present in the system to meet the PRM requirement.
- Add (or remove) the desired resource(s) to the portfolio. The addition of a new resource will result in an improvement in reliability, reducing the frequency of loss of load events.
- Re-adjust the system by removing (or adding) perfect capacity as necessary to restore reliability to the target standard. The amount of perfect capacity that can be removed from the system while maintaining the original reliability standard provides a measure of the resource's ELCC. This process typically requires iterative simulations in an LOLP model to identify the precise amount of equivalent perfect capacity.

26. Q. WHY IS ELCC THE PREFERRED METHODOLOGY FOR CAPACITY ACCREDITATION?

A. ELCC is the most robust measure of a resource's contribution to a utility's reliability standard. The ELCC method is the preferred method to measure capacity value for two primary reasons:

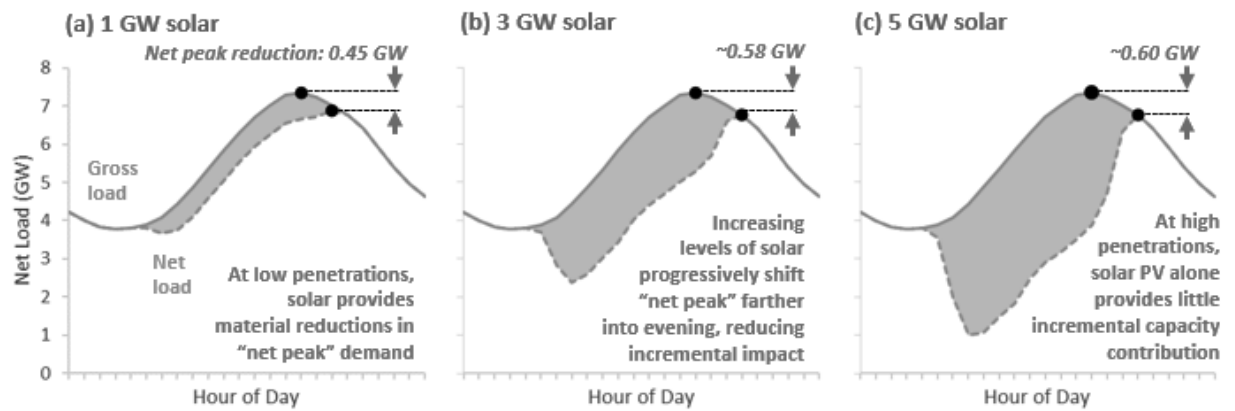
1. It captures a wide range of system conditions by simulating electric system operations over hundreds of years of plausible system conditions. This ensures that the calculation of capacity contributions is robust across a wide distribution of potential conditions, including infrequent tail events that are the primary drivers of reliability challenges (e.g. higher load and/or lower renewable output).

2. It naturally accounts for the interactive effects between different resources on the system. This includes both the saturation effects that occur as a particular resource type is added to the system in increasing quantities and the interactive effects between different technologies. By capturing these interactive effects, ELCC provides the most complete and accurate measurement of the contribution of variable and dispatch-limited resources to the system.

27. Q. CAN YOU PROVIDE AN EXAMPLE OF THE TYPES OF “SATURATION EFFECTS” THAT CAN BE CAPTURED BY THE ELCC APPROACH?

A. Yes. One example of the type of saturation effect that is captured by the ELCC approach is the declining marginal capacity value of solar resources at increasing scale. Because of the coincidence of solar production with the traditional afternoon peak period, the first increment of solar resources added to the system provides moderate capacity value, but it also has the effect of shifting the “net peak demand” – demand less variable renewables – towards the evening, when solar production is lower. As a result, subsequent increments of solar will produce lower and lower contributions to resource adequacy, typically reflected in declining marginal ELCCs for solar as a function of penetration. These dynamics are shown illustratively in Figure NS-2.

**FIGURE NS-2
ILLUSTRATION OF DECLINING MARGINAL CAPACITY VALUE OF SOLAR
RESOURCES**



Examples shown for illustrative purposes only based on a single day of load & renewable profiles and are not a model result

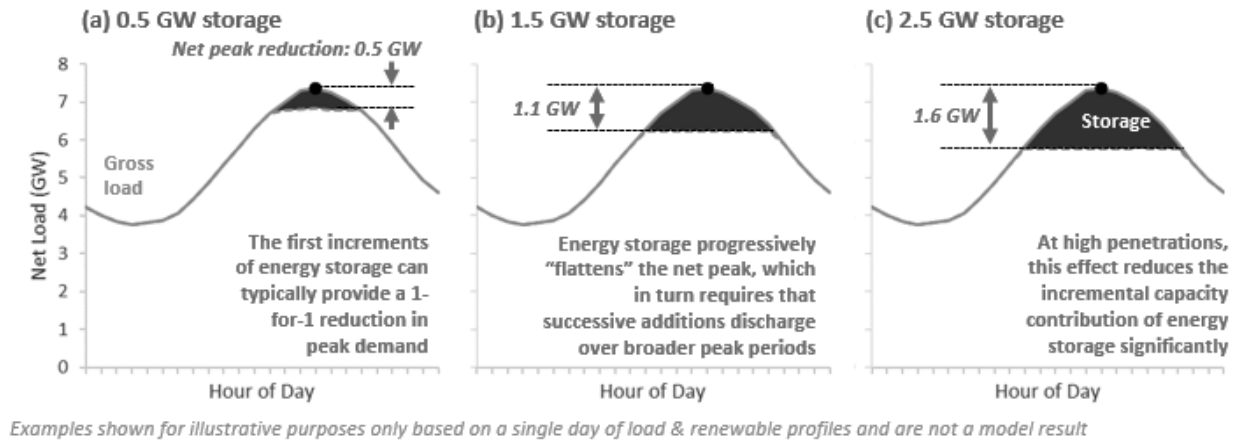
Saturation effects also apply to energy storage as well, but for a different reason: while energy storage resources can be operated flexibly in response to system conditions, they are unable to generate continuously at maximum output for long periods of time because of the limits of their state of charge. As successive tranches of storage are dispatched to meet peak demand, the next tranche of storage must discharge the peak over a longer period. These dynamics, which are also captured by the ELCC methodology, are shown illustratively in Figure NS-3.

///

///

///

**FIGURE NS-3
ILLUSTRATION OF DECLINING MARGINAL CAPACITY VALUE OF ENERGY
STORAGE RESOURCES**



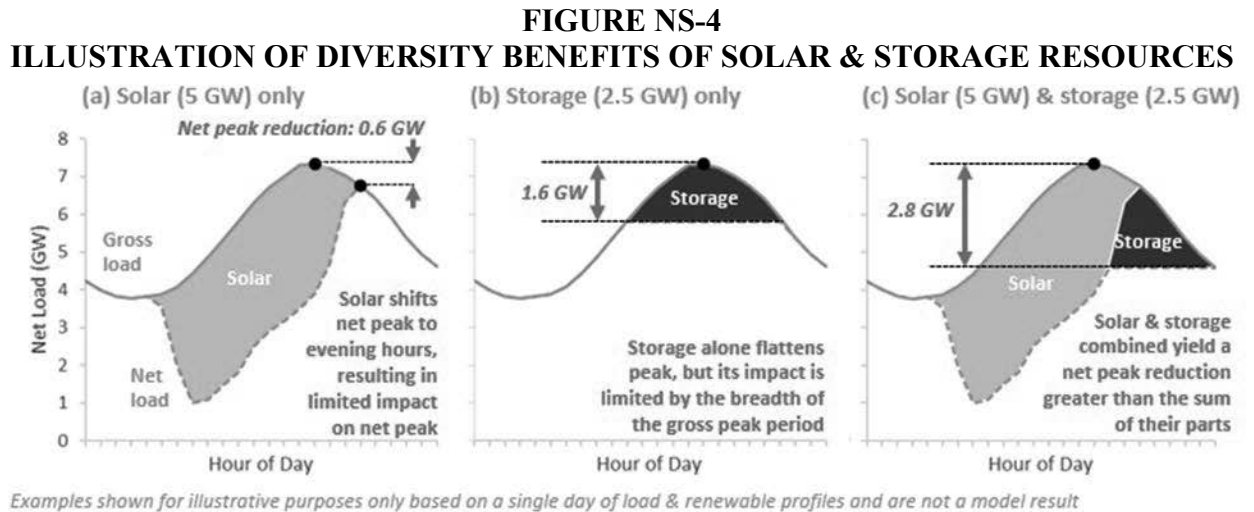
28. Q. CAN YOU ALSO PROVIDE AN EXAMPLE OF “DIVERSITY BENEFITS” BETWEEN TECHNOLOGIES CAPTURED BY AN ELCC APPROACH?

A. Yes. Solar and energy storage are an example of a complementary pair of technologies that typically exhibit diversity benefits, meaning that the total capacity value is greater than the sum of its individual parts. E3’s previous ELCC study for the Companies reflected this effect, and it has been observed in many other jurisdictions. For instance, E3’s *Resource Adequacy in the Desert Southwest* identifies a similar effect and describes how:

“...combinations of resources also exhibit interactive effects. In some cases, this can lead to outcomes where the total capacity value provided by a portfolio is greater than the sum of its individual parts. This is characteristically true of solar and storage resources, which form a natural complementary pair: as solar shifts load away from

the peak, it also reduces the duration of the ‘net peak’ period, allowing storage resources to contribute more effectively to resource adequacy.”¹²

These dynamics are shown illustratively in Figure NS-4 below.



29. Q. DOES AN ELCC APPROACH ACCOUNT FOR RISKS TO RELIABILITY THAT MAY OCCUR AT TIMES OUTSIDE OF THE PEAK PERIOD?

A. Yes. In any portfolio, the marginal ELCC – that is, the ELCC of the next increment of capacity of a specific type of resource – effectively represents what that resource can provide to the system during the periods of highest reliability risk, whenever they occur. What this means is that an ELCC approach will dynamically capture how reliability risks may shift outside of the traditional gross peak period. For instance, the declining marginal ELCC of solar is a reflection of the phenomenon

¹² E3, *Resource Adequacy in the Desert Southwest*, Feb. 2022, available at https://www.ethree.com/wp-content/uploads/2022/02/E3_SW_Resource_Adequacy_Final_Report_FINAL.pdf

that the increasing penetration shifts reliability risk later into the afternoon and evening (the “net peak”), at which point in time the availability of solar is lower than during the gross peak period. Similarly, the marginal ELCC of solar (or any resource) inherently accounts for the capacity value that it provides during all periods of potential reliability risk across the year. In a summer peaking system such as the Companies’, LOLP simulations typically show some loss of load risk across the summer months, and each resource’s marginal ELCC will account for its potential performance across all of those events.

III. 2024 RESOURCE ADEQUACY STUDY

III.A. 2024 RESOURCE ADEQUACY STUDY – METHODOLOGY & ASSUMPTIONS

30. Q. PLEASE DESCRIBE THE SCOPE OF THE 2024 RESOURCE ADEQUACY STUDY.

A. The scope of the Resource Adequacy Study is designed to answer three primary questions:

- What PRM requirement is needed to ensure the Companies can maintain resource adequacy?
- What is the portfolio ELCC of variable and energy-limited resources in the Companies’ “Base Portfolio?”¹³
- Beyond the Base Portfolio, what is the marginal ELCC of incremental renewables and energy storage resources at different levels of penetration?

¹³ Throughout my testimony and the accompanying technical appendices, I use the term “Base Portfolio” to refer to the combination of resources that are either currently operational in the Companies’ portfolio or have received the Commission’s approval. For this study, this includes resources approved by the Commission in the Fifth Amendment to the 2021 Joint IRP. In contrast, I use the term “incremental” to refer to potential future resource options that the Companies may propose to add to their portfolio, either in this filing or at a later date.

The analysis focuses on the period 2025-2028, chosen to reflect the general period of resource acquisitions the Companies are likely to make over the next several years. By focusing on this period, E3's study provides the Companies with the most useful information on its immediate resource adequacy needs and how different future resources options can contribute to meeting those needs.

31. Q. DOES THE APPROACH USED BY THE COMPANIES IN THIS FILING ADHERE TO THE BEST PRACTICES DESCRIBED ABOVE?

A. Yes. To conduct the resource adequacy analysis, this study uses RECAP, an industry-standard LOLP model developed and maintained by E3. This model is populated with inputs and assumptions developed in a robust manner and is used to evaluate the requisite PRM requirement and to calculate the ELCC of new resources consistent with the best practices described in Section II.C.

32. Q. PLEASE PROVIDE AN OVERVIEW OF THE RECAP MODEL.

A. RECAP analyzes the availability of generation to meet system needs across a wide range of possible system conditions using an hourly time-sequential Monte Carlo simulation. The range of conditions simulated captures load and renewable variability (based on an underlying record of weather data from 1990-2021) as well as stochastic outages of generating resources. Correlations between load and renewable generation are preserved within the model to ensure appropriate statistical relationships among load, weather, and renewable generation conditions, based on historical observations. Hourly simulations are completed for hundreds of years of potential conditions to ensure a statistically robust result; this ensures that RECAP captures a wide distribution of potential outcomes, including infrequent "tail" events as described earlier.

To calculate the LOLE of a specific portfolio, RECAP compares demand with available generation in each hour of the simulation. When the supply of resources is inadequate to meet load and minimum operating reserves in a given hour, this is counted as loss of load. RECAP determines the frequency of loss-of-load events across all simulation years and then calculates the LOLE as the number of days with loss-of-load events divided by the total number of years in the simulation.

33. Q. HAS RECAP BEEN USED IN OTHER JURISDICTIONS?

A. Yes. RECAP has been used by several utilities throughout North America to support resource adequacy planning:

- Black Hills Energy;
- El Paso Electric Company;
- NorthWestern Energy;
- Nova Scotia Power, Inc.;
- Portland General Electric;
- Puget Sound Energy;
- Sacramento Municipal Utilities District; and
- Salt River Project.

E3 has also used RECAP in studies of resource adequacy to support a diverse mix of clients, including the California Independent System Operator, California Public Utilities Commission, Los Angeles Department of Water and Power, the New York State Energy Research & Development Authority, the Public Generating Pool¹⁴, Puget Sound Energy, Avista, and Xcel Energy.

¹⁴ The Public Generating Pool is a consortium of thirteen publicly owned utilities in Washington and Oregon.

1 34. Q. HOW DOES THE SCOPE OF THIS STUDY COMPARE TO PREVIOUS
2 PRM AND ELCC STUDIES YOU HAVE SPONSORED ON BEHALF OF
3 THE COMPANIES?

4 A. The overall scope of the 2024 Resource Adequacy Study is very similar to the
5 previous analyses I have completed on behalf of the Companies: in both previous
6 studies and the current study, I use RECAP to (1) derive a PRM requirement and
7 (2) calculate ELCCs according to the processes described above. The current
8 analysis incorporates a number of data updates and several methodological
9 enhancements described below but follows the same general approach as previous
10 studies.

11
12 35. Q. RELATIVE TO YOUR PREVIOUS STUDIES FOR THE COMPANIES,
13 WHAT ARE THE MOST IMPORTANT UPDATES AND
14 ENHANCEMENTS TO METHODS, INPUTS, AND ASSUMPTIONS
15 INCORPORATED INTO THESE STUDIES?

16 A. Relative to previous analyses, this study incorporates several updates and
17 enhancements to methodology, data, and assumptions. Specifically:

- 18 • **Transition to UCAP accounting:** for the purposes of calculating the PRM
19 requirement, this study uses the “unforced capacity” (“UCAP”) approach to
20 accredit thermal resources rather than the more traditional “installed
21 capacity” (“ICAP”) approach historically used by the Companies. The
22 reasons for this transition are discussed subsequently in my testimony; the
23 impacts of this transition are both (a) a reduction in the PRM requirement,
24 and (b) a commensurate reduction in the capacity contributions attributed
25 to thermal resources.

- **Calibration to the Companies’ latest load forecast:** the hourly load shapes modeled in RECAP have been updated to align closely with the Companies’ 2024 Joint IRP base load forecast. This includes future expectations around changes in load shape due to electric vehicles and growth of demand from high load factor customers. These hourly load shapes are paired with historically synchronized renewable production profiles so that the load and renewable profiles modeled maintain “weather coherence.”
- **Updates to “Base Portfolio”:** the Base Portfolio represents the set of resources against which the PRM requirement is calibrated and from which marginal ELCCs for potential new resources are calculated. For this study, the Base Portfolio includes all resources currently in the Companies’ portfolio, including resources approved in the Fifth Amendment to the 2021 Joint IRP.
- **Storage outage rate:** this study incorporates a forced outage rate of 5% to energy storage resources. E3’s previous analysis of ELCCs did not include modeling of forced outages for energy storage.

36. Q. PLEASE DESCRIBE THE SIGNIFICANCE OF USING UCAP, RATHER THAN ICAP, ACCOUNTING TO COUNT THERMAL RESOURCES TOWARDS THE PRM.

A. Historically, it has been common practice among utilities to count thermal resources towards the PRM requirement based on their seasonal rated capacity – often referred to as ICAP accounting – and many utilities continue to use that convention today. In contrast, under UCAP accounting, the capacity contribution of each thermal resource is calculated by derating its seasonal rated capacity by the

probability of forced outages – typically measured using the equivalent forced outage rate on demand (“EFORd”). Applying UCAP accounting conventions to thermal resources also has direct implications for the PRM requirement itself. Under the ICAP approach, thermal resources are counted towards the PRM at their full rated capacity, and the PRM requirement includes some margin to account for the probability that one or more of those units may experience forced outages when needed. Under UCAP accounting, individual unit capabilities are instead derated from their rated capacity based on their probability of forced outages – meaning that the PRM requirement itself must also be lowered by a commensurate amount to avoid a double-counting the impacts of forced outages on total resource needs. Importantly, this downward revision does not imply a reduction in the total amount of resources needed to satisfy a specified reliability target – it simply reflects a different accounting convention.

37. Q. WHY SHOULD THE COMPANIES TRANSITION TO THE UCAP ACCOUNTING FRAMEWORK?

A. There are several reasons for the Companies to transition to a UCAP accounting approach for thermal resources:

1. Applying UCAP accounting to thermal resources improves alignment between the capacity accreditation methods used for thermal resources versus renewables and energy storage. This improved alignment allows the Companies to value the capacity contributions of potential new resources more uniformly across all technologies, in turn supporting the Companies’ efforts to identify the lowest cost resource options to meet its reliability needs.

2. The use of the UCAP approach also increases stability of the PRM requirement over time, as the requirement in a UCAP framework is less sensitive to changes in the thermal resource portfolio. For instance, changes to thermal plant outage rates based on new data can be accommodated through changes in the resource's UCAP without the need to adjust or recalibrate the PRM requirement. Similarly, additions and retirements of thermal resources have a lower impact on the requirement.

3. Adoption of the UCAP approach aligns the Companies' accounting practices with proposed capacity accreditation methods used in WRAP for thermal resources. Harmonizing the Companies' current conventions with the approach that is likely to be used within WRAP will allow for a smoother transition when WRAP requirements become binding.

38. Q. WHAT RELIABILITY STANDARD IS USED TO DETERMINE THE REQUIRED UCAP PRM FOR THE COMPANIES?

A. The Companies rely on the "1-day-in-10-year" reliability standard, or an LOLE of 0.1 days per year. This is the same standard that was used as the basis for E3's previous PRM and ELCC analyses and is consistent with industry standard practice.

39. Q. PLEASE DESCRIBE HOW LOAD AND RENEWABLE PROFILES FOR THE RESOURCE ADEQUACY STUDY ARE DEVELOPED.

A. An extensive dataset of load and renewable profiles spanning multiple weather years are essential for a robust PRM and ELCC study so as to capture both typical and extreme conditions with representative frequencies. These are developed through multiple steps:

1. Simulate hourly loads across an expansive range of weather conditions: for each year in the analysis horizon, E3 develops 32 unique hourly system load profiles, each of which represents a different realization of weather conditions based on the historical period 1990 to 2021. This is accomplished by developing by training a neural network regression model with recent historical load and weather data such that it can produce synthetic hourly load shapes across a longer sample of weather conditions. The resulting outputs are subsequently calibrated to align with the Companies' future electricity demand in each year (peak, energy, and seasonal profile).
2. Simulate hourly wind and solar generation across multiple years of weather conditions. E3 simulates hourly renewable profiles for solar and wind resources for each geographic site using National Renewable Energy Laboratory's (NREL) System Advisor Model and Wind Integration National Dataset (WIND) Toolkit. These simulations cover the historical periods 1998-2020 (solar) and 2007-2012 (wind).
3. Extend wind and solar profiles to match load simulation using statistical upsampling. Because the solar/wind profiles can only be simulated for a subset of the years included in the load profile, E3 uses a day-matching algorithm to extend the simulation of renewable profiles across the entire 32-year weather record studied.

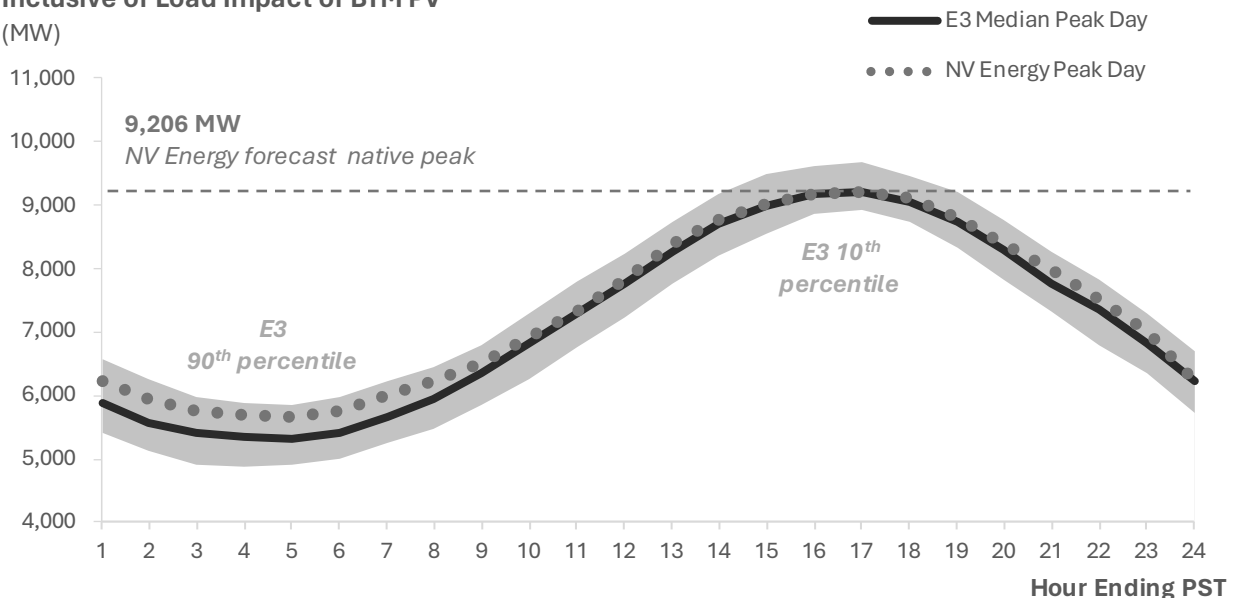
This process produces load, solar, and wind profiles that are "weather coherent," meaning that all three variables are representative of the same underlying weather conditions.

40. Q. DOES THE METHODOLOGY USED TO DEVELOP THE LOAD PROFILE FOR THIS STUDY YIELD RESULTS COMPARABLE TO THE COMPANIES' FORECAST?

A. Yes. The process used to develop the load profile results in close alignment between the representation of electricity demand in this study and the Companies' own demand forecast. As an example, Figure NS-5 compares the Companies' peak day load shape for 2028 with the range of peak day load shapes represented across E3's 32-year simulation. E3's profile is calibrated to align closely with the Companies' peak demand and the diurnal shape. The fact that E3's profiles span a broader range is a feature of this approach, which allows this analysis to capture lower-probability, more extreme weather conditions.

**FIGURE NS-5
COMPARISON OF THE COMPANIES' PEAK DAY LOAD SHAPE FOR 2028 WITH E3'S
2028 SIMULATED PEAK DAY LOAD SHAPES ACROSS 32 WEATHER YEARS**

**2028 NV Energy Peak Day Load Shapes
Inclusive of Load Impact of BTM PV
(MW)**



41. Q. PLEASE DESCRIBE THE COMPOSITION OF THE BASE PORTFOLIO OF RESOURCES INCLUDED IN THIS STUDY.

A. The Base Portfolio for this study includes the Companies' existing resources plus resources under development that have been approved by the Commission through the Fifth Amendment to the 2021 Joint IRP. Table NS-2 summarizes the rated capacity of the resources in the Base Portfolio by technology between 2025 and 2028. Relative to the Companies' portfolio today, this portfolio includes the following changes:

- Addition of Silver Hawk 1 & 2 (222 MW each) by 2025;
- Repowering of Valmy 1 & 2 with equivalent natural gas capacity by 2026; and
- Addition of Sierra Solar (400 MW) and BESS (400 MW) by 2028.

The Base Portfolio also captures a number of smaller changes in the Companies' portfolio over time.

**TABLE NS-2
RATED CAPACITY OF RESOURCES INCLUDED IN BASE PORTFOLIO BY YEAR
AND TECHNOLOGY**

Resource Type	2025	2026	2027	2028
Coal ¹	261	-	-	-
Natural Gas ¹	6,386	6,647	6,647	6,647
Solar PV ²	3,026	2,966	3,366	3,366
Concentrating Solar Power (CSP)	100	100	100	-
Energy Storage ^{2,3}	945	1,285	1,285	1,285
Geothermal	418	448	452	452
Hydro and Others ⁴	145	145	145	140
Wind	152	152	152	152
Demand Response	219	234	249	262
Total Resources	12,643	12,845	13,340	13,323

Notes:

1. Rated capacity for thermal resources during peak summer weather conditions
2. Solar PV and energy storage capacity includes resources that serve Liberty Utilities through 2025
3. Includes both standalone and paired storage capacity
4. Rated capacity is based on NV Energy's assumed capacity contributions

42. Q. WHAT IS THE BASIS FOR THE FIVE PERCENT OUTAGE RATE APPLIED TO ENERGY STORAGE IN THIS STUDY?

A. Typically, the development of outage rate assumptions for generators in LOLP modeling are derived from historical plant outage data. Because grid-scale battery storage is a relatively novel technology, availability of this data across the industry is limited. There is, however, clear evidence that battery storage facilities are susceptible to unforced outages: for instance, recent data published by CAISO has shown outage rates across the battery fleet on the order of ten percent.¹⁵ The assumption of a five percent outage rate balances the recognition of this risk with the expectation of potential for improvements in performance as energy storage matures from nascent technology to a widely deployed resource.

III.B 2024 RESOURCE ADEQUACY STUDY – KEY RESULTS

43. Q. WHAT PRM REQUIREMENT DID E3 FIND WAS NECESSARY TO MEET THE COMPANIES’ RELIABILITY STANDARD?

A. My analysis shows that a PRM requirement between 12.5 to 13 percent over the period from 2025 to 2028, expressed using UCAP accounting conventions for thermal resources, is necessary to achieve the desired “one day in 10 years” reliability standard, or an LOLE of 0.1 days per year. Based on these results, I recommend that the Companies utilize a 12.5 percent PRM requirement, which is equal to the requirement I calculated for 2028.

¹⁵ See E3, *presentation to APS’ Resource Planning Advisory Council*, slide 45, Oct 26, 2022, available at <https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/APS-RPAC-Meeting-Presentation-102622.ashx?la=en&hash=9AE20E699D178AF8CF8AB30BF9C64FFED>.

1 44. Q. HOW DOES THIS COMPARE TO THE PRM REQUIREMENT
2 DETERMINED IN YOUR PREVIOUS STUDY?

3 A. In my previous analysis, which I sponsored in the Companies' 2021 Joint IRP, I
4 found that a 16 percent PRM requirement would be needed to meet the same
5 standard. Because this result was calculated using an ICAP accounting conventions
6 for thermal resources – which differ from the UCAP conventions used in the present
7 analysis – it is not directly comparable to the value I calculate in this study.
8

9 45. Q. IS IT POSSIBLE TO COMPARE THE RESULTS OF YOUR CURRENT
10 ANALYSIS TO YOUR PREVIOUS STUDY?

11 A. Yes. To allow for comparison and benchmarking to prior work, I have also
12 calculated the corresponding PRM requirements using ICAP accounting
13 conventions in the current study for informational purposes. The resulting ICAP
14 PRM requirements, which range between 16-17 percent, are slightly higher but
15 generally consistent with the results of the previous study. This is to be expected,
16 as the major drivers that would affect the ICAP PRM requirement (weather
17 variability, operating reserves, and thermal plant outage rates) have not changed
18 substantially.
19

20 This comparison is also useful for another reason: it serves as a reminder that the
21 lower UCAP value for the PRM in the present analysis does not represent a
22 reduction in the resources needed to ensure reliability, but merely reflects a change
23 in accounting conventions. Because capacity credits assigned to thermal resources
24 are also commensurately lower in a UCAP accounting framework, the additional
25 capacity need is largely unimpacted.
26
27

46. Q. PLEASE SUMMARIZE WHAT YOUR STUDY SHOWS REGARDING THE CAPACITY CONTRIBUTION OF RENEWABLES & STORAGE IN THE BASE PORTFOLIO.

A. In 2028, the Base Portfolio includes 3,366 MW solar PV, 1,285 MW energy storage (a portion of which are co-located with solar PV facilities), 152 MW wind, and 452 MW geothermal. My analysis indicates that this portfolio provides a total portfolio ELCC of 1,994 MW. This value is calculated using a standard ELCC methodology (comparing the system with and without these resources) and therefore reflects their capacity contribution in aggregate, accounting for interactive effects. For the purposes of the companies' loads and resources accounting, I allocate this total ELCC values to the individual technologies in proportion to each technology's decremental ELCC – that is, the ELCC calculated by removing that technology from the Base Portfolio. These results are summarized in Table NS-3.

**TABLE NS-3
CAPACITY CONTRIBUTIONS FOR RENEWABLES & STORAGE IN THE BASE
PORTFOLIO CALCULATED USING AN ELCC APPROACH**

Resource Type	Total Rated Capacity (MW)	Step 1: Technology Specific Decremental ELCC (MW)	Step 2: Portfolio ELCC (MW)	Step 3: Adjusted Technology Specific ELCC (MW)	Adjusted Technology Specific ELCC (%)
Geothermal	452	186	1,994	180	40%
Solar PV	3,366	710		685	20%
Storage	1,285	1,151		1,112	87%
Wind	152	18		17	11%
Total	5,255	2,065		1,994	-

The fact that the portfolio ELCC is lower than the sum of the technology-specific decremental ELCCs is due to interactive effects and indicates the presence of a

diversity benefit between technologies. This is because the calculation of each technology's decremental ELCC independently reflects the interactive effects between that technology and the rest of the portfolio, meaning that the interactive effects between resources are accounted for multiple times in the sum of the technology-specific values and must be scaled down to avoid overcounting the value of the portfolio.

47. Q. WHAT INCREMENTAL RESOURCES BEYOND THE BASE PORTFOLIO DID YOU EXAMINE IN THE ELCC STUDY?

A. My study quantified the incremental ELCC associated with a wide range of potential future renewable and energy storage resource additions. These include:

- An ELCC "surface" reflecting combinations of solar and storage ranging from 0 to 40,000 MW of solar and 0 to 30,000 MW of four-hour battery storage;
- Several sensitivities to explore the marginal ELCC value of two- and eight-hour storage;
- Marginal ELCC curves for four different wind resources, each representative of a different geographic area (Arizona, Idaho, Nevada, and Wyoming), at penetrations of 0 to 10,000 MW; and
- A marginal ELCC curve for geothermal resources up to 5,000 MW.

The ranges of penetration studied in this analysis, which reflect scales on the order of 10,000 MW, are very large by design, intended to allow for these values to be used throughout the long-term analysis horizon and in subsequent filings.

48. Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ELCC ANALYSIS OF INCREMENTAL SOLAR AND ENERGY STORAGE.

A. To inform the Companies' future planning and resource selection, I analyze the ELCCs of a wide range of combinations of new solar and four-hour energy storage resources. The result of this analysis is an ELCC "surface," shown in Table NS-4. The value in each cell of this table represents the total capacity value provided by the corresponding quantities of solar and storage; for instance, 2,000 MW of additional solar and 2,000 MW of additional storage would provide an additional 1,739 MW of capacity value.

**TABLE NS-4
INCREMENTAL ELCC (MW) FOR VARIOUS COMBINATIONS OF SOLAR AND
ENERGY STORAGE**

		Incremental Four Hour Storage Capacity (MW)									
Incremental Solar Capacity (MW)	0	0	500	1,000	1,500	2,000	3,000	4,000	5,000	10,000	30,000
	250	13	465	862	1,222	1,447	1,657	1,755	1,844	2,133	2,674
	500	27	486	897	1,256	1,499	1,734	1,834	1,926	2,216	2,762
	1,500	76	536	986	1,379	1,672	2,007	2,140	2,245	2,549	3,109
	2,000	93	556	1,002	1,424	1,739	2,110	2,287	2,395	2,711	3,283
	5,000	159	630	1,085	1,529	1,899	2,370	2,697	2,983	3,590	4,253
	10,000	222	683	1,140	1,587	1,986	2,500	2,836	3,172	4,565	5,606
	20,000	263	721	1,178	1,634	2,040	2,587	2,937	3,279	4,897	6,240
	40,000	281	742	1,203	1,658	2,071	2,643	3,016	3,368	5,044	6,960

49. Q. WHY IS IT NECESSARY TO CREATE THIS TWO-DIMENSIONAL SURFACE FOR SOLAR AND STORAGE RESOURCES?

A. In my discussion of resource adequacy best practices earlier in this testimony, I discuss the importance of interactive effects (or diversity benefits) between solar and storage, and this surface provides a quantitative means of characterizing those interactive effects for use in planning. As an example, based on the values in Table NS-4:

- Without any additional solar, an additional 2,000 MW of storage would provide 1,382 MW of capacity value.

- Without any additional storage, an additional 2,000 MW of solar would provide 93 MW of capacity value.
- The combination of 2,000 MW of storage and 2,000 MW of solar would provide 1,739 MW, 264 MW more (or nearly 20% higher) than the sum of the independent resources (1,382 MW + 93 MW = 1,475 MW).

This diversity benefit results simply from the complementary characteristics of solar and storage resources when both are present in the electricity system together (i.e. there is no need for co-location or hybridization to achieve these benefits).

50. Q. WHAT DOES THE SOLAR-STORAGE ELCC SURFACE SHOW REGARDING THE MARGINAL ELCC OF ADDITIONAL SOLAR PV RESOURCES?

A. The values in Table NS-4 can be used to impute marginal ELCC values for solar PV at different levels of penetration. Table NS-5 shows these values; each column in this table can be interpreted as a marginal ELCC curve for solar PV at a specified level of energy storage penetration.

**TABLE NS-5
MARGINAL ELCC (%) FOR ADDITIONAL SOLAR PV GENERATION**

		Incremental Four Hour Storage Capacity (MW)									
		0	500	1,000	1,500	2,000	3,000	4,000	5,000	10,000	30,000
Incremental Solar Capacity (MW)	0	-	-	-	-	-	-	-	-	-	-
	250	5%	11%	14%	24%	26%	31%	31%	34%	35%	35%
	500	5%	8%	14%	14%	21%	31%	31%	33%	33%	35%
	1,500	5%	5%	9%	12%	17%	27%	31%	32%	33%	35%
	2,000	3%	4%	3%	9%	13%	21%	29%	30%	32%	35%
	5,000	2%	2%	3%	4%	5%	9%	14%	20%	29%	32%
	10,000	1%	1%	1%	1%	2%	3%	3%	4%	20%	27%
	20,000	0%	0%	0%	0%	1%	1%	1%	1%	3%	6%
	40,000	0%	0%	0%	0%	0%	0%	0%	0%	1%	4%

From these values, several observations and trends are noteworthy:

- The marginal ELCC of new solar PV resources relative to the Base Portfolio (i.e. with 0 MW of additional storage) is relatively low (<10%). This is a result of the fact that the penetration of solar in the Base Portfolio is sufficient to shift loss of load risk into the evening hours when production from solar resources is low or zero. In other words, when the “net peak” has shifted into the evening hours, the marginal ELCC of additional solar is limited.
- At higher penetrations of storage, the marginal ELCC of solar resources at a given level of penetration rises. This once again represents the diversity benefit and is an indication of the fact that at high penetrations of storage, additional energy at any time of day – even outside of net peak hours – provides reliability value, as the latent flexibility of energy storage allows it to be shifted to periods when needed. For this reason, at very high penetrations of storage, the marginal ELCC of solar (30-35%) approaches a level consistent with the average summer capacity factor of solar.

51. Q. WHAT DOES THE SOLAR-STORAGE ELCC SURFACE SHOW REGARDING THE MARGINAL ELCC OF ADDITIONAL ENERGY STORAGE RESOURCES?

A. Similarly, the values in Table NS-4 can also be used to impute marginal ELCC values for energy storage at different levels of penetration. Table NS-6 reports these values; each row of this table can be interpreted as a marginal ELCC curve for energy storage at a specified level of solar penetration.

**TABLE NS-6
MARGINAL ELCC (%) FOR ADDITIONAL ENERGY STORAGE**

		Incremental Four Hour Storage Capacity (MW)									
Incremental Solar Capacity (MW)	0	0	500	1,000	1,500	2,000	3,000	4,000	5,000	10,000	30,000
	250	-	87%	78%	67%	44%	20%	10%	8%	6%	3%
	500	-	90%	79%	72%	45%	21%	10%	9%	6%	3%
	1,500	-	92%	82%	72%	49%	24%	10%	9%	6%	3%
	2,000	-	92%	90%	79%	59%	33%	13%	10%	6%	3%
	5,000	-	93%	89%	84%	63%	37%	18%	11%	6%	3%
	10,000	-	94%	91%	89%	74%	47%	33%	29%	12%	3%
	20,000	-	92%	91%	89%	80%	51%	34%	34%	28%	5%
	40,000	-	92%	92%	91%	81%	55%	35%	34%	32%	7%
		-	92%	92%	91%	83%	57%	37%	35%	34%	10%

As with solar, several trends are notable in the changing marginal ELCCs for storage:

- The marginal ELCC of energy storage resources at low penetrations is relatively high (90% of nameplate capacity or higher) but declines with increasing penetration. This is because the portfolio becomes increasingly “energy constrained,” requiring resources capable of operating at full capacity over longer periods of time. At very high penetrations of storage, marginal ELCCs decline to levels below 10%.
- The decline of storage marginal ELCC occurs more slowly at higher penetrations of solar. This is also a manifestation of the aforementioned diversity benefit between solar and storage, whereby higher penetrations of solar both (1) compress the window of time during which storage discharge is necessary in the afternoon and evening, and (2) provide energy that helps ensure storage resources are sufficiently charged prior to this window.

52. Q. TO WHAT EXTENT ARE THESE RESULTS CONSISTENT WITH YOUR PREVIOUS ANALYSIS OF SOLAR & STORAGE ELCCS?

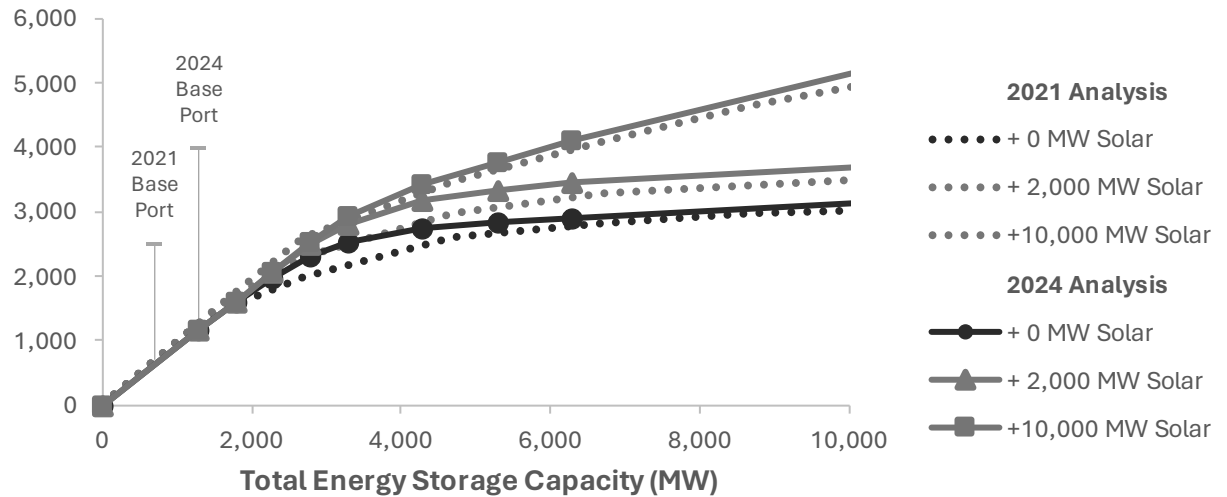
A. The ELCC results in the current analysis are very similar to previous study results. Figure NS-6 compares cumulative ELCC curves¹⁶ for four-hour energy storage obtained in the current study with the results of my previous analysis; while some differences are present, these are largely explained by updates to assumptions in this study:

- At lower penetrations (<2,000 MW), the total capacity contribution of storage is slightly lower than in the previous study; this can largely be attributed to the incorporation of a 5% forced outage rate in the calculation of storage ELCCs in the current study.
- At higher penetrations, the total capacity contribution of storage is slightly higher than in the previous study. This is largely a result of the fact that the demand forecast in the current study has increased relative to the forecasts used in previous studies; the higher load forecast used in this study results in the saturation of energy storage occurring at a slower pace, or a slower decline in the marginal ELCC at increasing penetrations.

¹⁶ Each “cumulative ELCC curve” reflects a cross-section of the solar-storage surface (i.e. holding solar penetration constant at a prescribed level, the cumulative curve reflects how much additional capacity value incremental energy storage resources provide).

**FIGURE NS-6
COMPARISON OF CUMULATIVE STORAGE ELCC CURVES FOR CURRENT AND
PREVIOUS ELCC STUDIES**

**Cumulative Storage ELCC Curves
2021 vs. 2024 ELCC Studies**
(MW)



53. Q. **WHAT DOES YOUR STUDY FIND REGARDING THE MARGINAL ELCC OF INCREMENTAL WIND RESOURCES?**

A. In this study, marginal ELCC curves are developed for four representative wind resources, representative of wind regimes in Arizona, Idaho, Nevada, and Wyoming. For all wind resources, marginal ELCCs begin at approximately 30% and decline at higher penetrations as loss of load risk shifts to periods of lower wind output:

- The first 500 MW of new wind resources would provide a capacity contribution between 129 and 141 MW, implying an ELCC of 26-29% (variations correspond to different wind regimes);
- The next 500 MW of new wind resources would provide 97-111 MW of additional capacity value, implying an ELCC of 19-22%; and
- A third 500 MW increment would provide 72-92 MW of additional capacity value, implying an ELCC of 14-18%.

At higher penetrations, marginal ELCCs continue to decline to levels below 10%.

54. Q. WHAT DOES YOUR STUDY FIND REGARDING THE MARGINAL ELCC OF INCREMENTAL GEOTHERMAL RESOURCES?

A. The marginal ELCC of incremental geothermal resources is approximately 40%, a value that remains constant even at high penetrations. This corresponds to the average output of the assumed geothermal profile during the net peak period. Because this is also the minimum output of the geothermal resource profile, the saturation effects observed for wind and solar – which result from increasing penetrations of those resources causing loss of load risk to shift to periods when their respective output is lower – is not observed for geothermal.

III.C 2024 RESOURCE ADEQUACY STUDY – CONCLUSIONS AND FINAL OBSERVATIONS

55. Q. YOUR PRM AND ELCC ANALYSIS FOCUSES ON THE PERIOD 2025-2028. IS IT REASONABLE TO USE THE RESULTS OF THIS STUDY ACROSS THE FULL PLANNING HORIZON (20+ YEARS)?

A. Yes. It is the intent of this analysis that the PRM requirement developed for 2028 would be a suitable proxy for a long-term PRM requirement for the Companies, so long as UCAP and ELCC accounting conventions are used in conjunction. Similarly, the ELCC curves for each technology provide a reasonable basis for long-term planning assumptions.

1 **56. Q. IS IT REASONABLE THAT THE COMPANIES WOULD CONTINUE TO**
2 **USE THE VALUES PRODUCED IN THIS ANALYSIS IN SUBSEQUENT**
3 **FILINGS?**

4 A. Yes. The nature of the approach taken in this study, which directly captures how
5 the ELCC of new resources change as a function of their penetration, should allow
6 these values to be used by the Companies even as their loads and resources evolve.
7 For this reason, I would expect that the Companies could continue to utilize these
8 values until material changes in circumstances that would affect these results
9 necessitate an update.

10
11 **57. Q. UNDER WHAT CIRCUMSTANCES SHOULD THE COMPANIES**
12 **CONSIDER UPDATING THE PRM AND ELCC STUDY RESULTS?**

13 A. Factors that could trigger the need to reevaluate the PRM requirement and ELCC
14 curves could include:

- 15 • Significant changes to the composition of the resource portfolio not
16 contemplated within the scope of this study;
- 17 • Major revisions to the Companies' load forecast, particularly those that would
18 impact the hour-to-hour shape or seasonality of demand;
- 19 • Improvements to the understanding of risks surrounding potential extreme
20 weather events, particularly in the context of climate change.

21
22 **58. Q. IF THE COMPANIES USE THE PRM AND ELCC VALUES PROVIDED**
23 **BY YOUR STUDY, DOES THAT MEAN THAT THE SYSTEM WILL**
24 **NEVER HAVE RELIABILITY EVENTS?**

25 A. No. The PRM and the ELCC values for dispatch-limited resources derive from a
26 specified reliability target. The reliability target used by the Companies is a LOLE
27

of 0.1 days per year. If the system has an adequate supply of resources, then on average, the system will have enough resources to meet load on every day but one in a ten-year time span.¹⁷ Additionally, other factors not traditionally considered within the scope of resource adequacy may cause reliability events, such as outages on the transmission or distribution systems.

VI. 2024 SIERRA SUBSYSTEM RESOURCE ADEQUACY ANALYSIS

59. Q. PLEASE DESCRIBE THE PURPOSE OF THE SIERRA SUBSYSTEM RESOURCE ADEQUACY ANALYSIS.

A. The 2024 Resource Adequacy Study used to establish the PRM and ELCC values for the Companies' planning focuses on the joint system as an integrated whole and does not consider internal transmission constraints. The implicit assumption is that internal transmission, such as the south-to-north import limit between Nevada Power and Sierra, would not materially impact the Companies' ability to operate the joint system to meet the combined needs of Sierra and Nevada Power. The Sierra Subsystem Study is a supplement to the joint system analysis, intended to examine the extent to which the transmission limit between Nevada Power and Sierra may result in additional reliability risk in the Sierra subsystem.

60. Q. PLEASE DESCRIBE HOW THIS ANALYSIS WAS CONDUCTED.

A. This analysis applies the same LOLP modeling techniques and assumptions to the Sierra subsystem that are used in the 2024 Resource Adequacy Study. The analysis focuses on the same Base Portfolio in the year 2028 and includes the subset of

¹⁷ Resource adequacy does not consider potential reliability events on the distribution system, which can result from a variety of local factors (e.g. high winds).

resources physically located within the Sierra subsystem, which are simulated against a 32-year load profile calibrated to align with the Companies' demand forecast for Sierra. For the purposes of LOLP simulations, the south-to-north import limit is treated as a perfectly available resource.

61. Q. WHAT IMPORT LIMITATIONS DID YOU STUDY IN THIS ANALYSIS?

A. I study three scenarios of transmission import limits: (1) current system limits (600 MW); (2) import limits following the completion of Greenlink West (644 MW); and (3) import limits following the completion of Greenlink West and North (1,444 MW). These import limits, which correspond to the amount of capacity available for use by Companies' retail customers (i.e. after reservations for wholesale customer use), were provided by the Companies.

62. Q. WHAT DOES YOUR ANALYSIS SHOW REGARDING THE RELIABILITY OF THE SIERRA SUBSYSTEM?

A. Simulating the Sierra subsystem in 2028 as described above, I find that the resources in the Base Portfolio yield a range of LOLE results that depends on the transmission limit. These results are summarized in Table NS-7. It is also worth noting that because this analysis focuses on the Base Portfolio, which does not include new resources proposed by the Companies in this filing, these results should not be interpreted as a projection of the actual level of reliability expected in the Sierra subsystem.

**TABLE NS-7
LOLE RESULTS FOR BASE PORTFOLIO IN SIERRA SUBSYSTEM IN 2028**

Import Scenario	Sierra Import Capacity (MW)	2028 Base Portfolio LOLE (days/yr)
Current System	600	2.6
+ Greenlink West	644	1.7
+ Greenlink West & North	1,444	0.0

63. Q. HOW SHOULD THESE RESULTS BE INTERPRETED?

A. There are two important findings that can be gleaned from these results:

- (1) With both Greenlink Nevada projects in service, the simulation indicates minimal reliability risk in the Sierra subsystem in the Base Portfolio. This implies that as long as sufficient resources are available within the joint system, the south-to-north import limit would not prevent those resources from being delivered to the Sierra's loads during critical periods when needed to ensure reliability. In turn, this validates the assumption made in the joint system resource adequacy study (that the two subsystems can be jointly planned for reliability purposes) so long as import capability to the Sierra subsystem is expanded with the Greenlink West and North projects.
- (2) Without the two Greenlink Nevada projects in service, the simulation shows a risk of loss-of-load events of over two days per year, a value much higher than the Companies' planning standard for the joint system of 0.1 days per year. This implies that without the Greenlink Nevada projects, the south-to-north transmission limit could result in LOLE risk specific to the Sierra subsystem even if the joint system is adequately planned to the 0.1 days per year standard. This is because the transmission constraint between Nevada Power and Sierra could limit the use of resources physically

located in the south to meet the Sierra subsystem needs during critical periods. This, in turn, indicates that additional generation capacity would be needed specifically within the Sierra subsystem if the Greenlink Nevada projects are not completed.

64. Q. CAN YOU EXPAND UPON THE IMPLICATIONS OF THE FINDING THAT ADDITIONAL CAPACITY RESOURCES WOULD BE NEEDED IN THE SIERRA SUBSYSTEM IF THE GREENLINK PROJECTS ARE NOT COMPLETED?

A. Yes. The implication is that without the Greenlink Nevada projects, the Companies would likely need to establish and plan to a separate, independent reliability standard for the Sierra subsystem to ensure that enough generation capacity is available locally during critical periods due to the transmission import limits.

65. Q. DO YOU HAVE THE ABILITY TO QUANTIFY HOW MUCH ADDITIONAL CAPACITY WOULD BE NEEDED IN THE SIERRA SUBSYSTEM UNDER THESE CIRCUMSTANCES?

A. Yes. Similar to the system study, the results of my analysis can be used to determine the PRM requirement that would need to be applied to the Sierra subsystem under circumstances that it was independently planned to meet a 0.1 days per year standard. While the Companies do not currently separately plan the Sierra subsystem to this standard, it is a reasonable proxy to use for these purposes given its common use across the industry and by the Companies for joint system planning. The UCAP PRM requirement for the Sierra subsystem corresponding to a 0.1 days per year standard, which provides a first-order approximation of the amount of

additional capacity needed under a transmission-constrained future, is 18 percent, measured relative to Sierra's non-coincident peak.

66. Q. WHAT ARE THE FACTORS THAT CONTRIBUTE TO THIS REQUIREMENT EXCEEDING THE 12.5 PERCENT REQUIREMENT YOU CALCULATED FOR THE JOINT SYSTEM?

A. There are three primary reasons that this requirement is higher than the joint system requirement, all of which stem fundamentally from the fact that the Sierra subsystem is small relative to the joint system as a whole:

- (1) The effect of "lumpy" thermal unit outages on a relatively smaller system. On the smaller Sierra subsystem, the effect of each individual thermal plant outage is magnified, as each outage represents a larger proportion of load. This contributes to thermal plant outages being a more significant driver of resource adequacy risk, which in turn translates to a need for additional capacity.
- (2) Higher operating reserve needs under a transmission-constrained scenario. In the zonal analysis, the operating reserve requirement is determined by the most severe single contingency, assumed in this analysis to be the loss of a single gas turbine at the Tracy Combined Cycle plant (which reduces the capacity of the thermal fleet by 294 MW). This analysis assumes that half of this contingency must be met by spinning reserves, leading to an operating reserve requirement of 165 MW for the Sierra subsystem – approximately six percent of peak demand (compared to approximately four percent for the joint system analysis).
- (3) Lower levels of load diversity: smaller systems with a more concentrated geographic footprint typically have lower levels of load diversity, which can translate to higher year-to-year variance in peak demand. This, in turn, is a contributing factor to a higher PRM requirement.

1 **67. Q. IS IT TO BE EXPECTED THAT THE SIERRA SUBSYSTEM, IF PLANNED**
2 **INDEPENDENTLY, WOULD REQUIRE ADDITIONAL CAPACITY TO**
3 **MAINTAIN RESOURCE ADEQUACY?**

4 A. Yes. It is an axiomatic principle of resource adequacy planning that pooling loads
5 and resources across a broader geographic footprint allows for a lower total quantity
6 of resources to meet a specified reliability standard than if sub-areas within that
7 system independently planned to that same reliability standard. This idea is
8 generally accepted across the industry and is one of the principal motivating factors
9 behind nearly all resource adequacy sharing programs, including WRAP (which
10 represents an application of these same concepts to an even broader geography):

11
12 “At its core, WRAP’s value proposition is greater regional reliability
13 and situational awareness and the potential for cost and resource
14 savings through diversity benefits of the loads and resources
15 committed to WRAP. The WRAP’s value proposition relies on
16 participants having access to their demonstrated (forward contracted
17 and owned) resources and confidence in the operational sharing of
18 resources within the WRAP footprint to safely lower the regional
19 planning reserve margin.”¹⁸

20
21 **68. Q. YOU DESCRIBE THIS HIGHER PRM AS A “FIRST ORDER**
22 **APPROXIMATION” OF THE ADDITIONAL RESOURCE NEED**
23 **RESULTING FROM HAVING TO PLAN THE SIERRA SUBSYSTEM**
24 **INDEPENDENTLY. WHAT DOES THIS MEAN?**

25
26 ¹⁸ Western Power Pool, *White Paper on WRAP Interoperability with Markets*, Jun. 16, 2023, available at
27 https://www.westernpowerpool.org/private-media/documents/WPP_WRAP_Interoperability_with_Markets_June_2023.pdf.

A. I describe this calculation as a “first order approximation” because there are a number of other effects that are not captured in this analysis that the Companies would need to consider if planning for resource adequacy in the Sierra and Nevada Power subsystems was bifurcated due to limitations on internal transmission between the two. Examples of these types of effects include:

- In addition to establishing a PRM requirement for Sierra, the Companies would likely also need to develop a separate PRM requirement for Nevada Power. For the same reasons the requirement for Sierra is higher than the joint system requirement, it is likely that the requirement for Nevada Power would be higher as well (though because Nevada Power is larger than Sierra, the increase would likely be smaller than the increase for Sierra).
- This analysis does not account for any impacts to the ELCCs for resources within the Sierra subsystem. In a complete implementation of an independent resource adequacy standard for Sierra, the Companies would also need to reevaluate the ELCCs for variable and energy-limited resources based upon their contributions to Sierra’s reliability needs (rather than their contribution to joint system reliability needs).
- If the Sierra subsystem was planned independently, a formal examination of the operating reserve needs of that system could yield different results than the assumptions used in this study.

69. Q. CAN YOU PROVIDE ANY INDICATION OF HOW SIERRA-SPECIFIC ELCCS FOR VARIABLE AND ENERGY-LIMITED RESOURCES WOULD DIFFER FROM JOINT SYSTEM ELCCS?

A. While it is difficult to surmise exactly how ELCCs would change, there are multiple reasons that I would expect Sierra-specific ELCCs would likely be lower than joint system ELCCs. For example:

- On smaller electricity systems, saturation effects typically begin to occur at lower absolute levels of capacity. This means that marginal ELCCs for variable and energy-limited resources would likely decline more quickly than at the system level.
- One of the reasons for the higher UCAP PRM in the Sierra subsystem is that thermal plant outages are a larger contributor to reliability risk than at the system level. This is because individual plant outages are “lumpy”. This, in turn, causes reliability risk to be spread across longer periods of time, a dynamic that is reflected in Figure NS-7, which shows the timing of loss-of-load risk for the joint system compared to the Sierra subsystem. The spread of risk across more extended periods would tend to reduce the ELCCs of energy-limited resources such as batteries.

**FIGURE NS-7
RELATIVE TIMING OF LOSS OF LOAD RISK IN THE COMPANIES’ JOINT SYSTEM
VERSUS SIERRA SUBSYSTEM**

Relative Loss-of-Load Risk by Hour of Day

NV Energy Joint System
LOLH = 0.18 hrs/yr

*Risk highly
concentrated in
short periods at
net peak*

Sierra Subsystem
LOLH = 0.30 hrs/yr

*Risk spread across
longer periods
before and after
net peak*

Hour Ending PST

V. UNCERTAINTY RESERVES STUDY

70. Q. WHAT ARE “UNCERTAINTY RESERVES?”

A. “Uncertainty reserves” refer to a type of operating reserve whose purpose is to ensure that grid operators have sufficient flexibility to rebalance generation output in response to forecast errors associated with load, wind and solar. This terminology is typically used to refer to deviations between forecasts at a day-ahead or hour-ahead time frame and actual conditions at a five-minute time scale, making it distinct from (1) “regulating” reserves, typically used to respond to variations in conditions within the five-minute time frame, and (2) contingency reserves, held by operators to respond to large and expected contingencies (e.g. a large plant or transmission line outage). In other jurisdictions, “uncertainty reserves” have also been described as “load following reserves” or “flexibility reserves.”

71. Q. WHAT FACTORS IMPACT A UTILITY’S NEED FOR UNCERTAINTY RESERVES?

A. The level of uncertainty reserves is primarily a function of three variables: expected forecast errors associated with load, solar generation, and wind generation. The level of uncertainty reserves needed will change over time – both on an hour-to-hour time scale as system conditions change and on a year-to-year time scale as the generation portfolio changes. In particular, as the penetration of solar and/or wind generation increases, the need for uncertainty reserves will also increase, requiring additional flexibility from flexible generation resources to manage forecast errors and uncertainty.

72. Q. PLEASE DESCRIBE THE SCOPE OF E3'S ANALYSIS OF UNCERTAINTY RESERVES.

A. The Companies requested that E3 conduct an analysis of future uncertainty reserve needs based on day-ahead forecast errors as a function of changing load, solar penetration, and wind penetration. E3's analysis used recent historical data provided by Companies to develop forward-looking requirements at different levels of load and renewable penetration. These requirements were developed as inputs for the Companies' PLEXOS ST production simulation analysis.

73. Q. WHAT METHODOLOGY DID E3 USE TO CALCULATE UNCERTAINTY RESERVES?

A. E3 developed uncertainty reserves by creating a machine learning model based on historical data that can be used to project future reserve requirements. This process involved three steps:

- **Gather historical forecast and actual profiles.** E3 gathered hourly forecasts and five-minute actuals from the Companies' joint system covering the period 2020 and 2022. Synchronized forecasts and actuals for load, solar, and wind are necessary to characterize the distributions of forecast error associated with each, along with covariance between them.
- **Use historical data to train a machine learning model.** The model is trained to determine the minimum level of uncertainty reserves that would be needed to ensure a certain level of confidence (e.g. 95th percentile) that actual deviations in "net load" (load minus output from wind and solar") would not exceed that threshold. Naturally, that threshold changes from hour to hour as a function of system conditions.

- **Apply machine learning model to future projections of load, wind, and solar.** Once the model has been trained to produce reserve requirements as a function of load, wind, and solar conditions, E3 provided the model with future projections of the Companies' hourly load, solar generation, and wind generation. This was repeated for several portfolios in order to parameterize relationships between renewable penetration and reserve requirements in a manner that allowed for calculation of uncertainty reserves across a wide range of portfolios.

74. Q. HAS E3 USED THIS METHODOLOGY IN OTHER STUDIES?

A. Yes. There is not currently a single accepted industry standard method used to calculate uncertainty reserves, but E3 has applied similar methods to develop input assumptions in several other studies, including:

- Development of reserve requirements for E3's study *Investigating the Economic Value of Flexible Solar Power Plant Operation*,¹⁹ conducted in partnership with Tampa Electric Company and FirstSolar; and
- Development of reserve requirements for fourteen WECC balancing authorities used in a CAISO-led study of the impacts of the proposed Enhanced Day-Ahead Market.

The more recent integration of machine learning into the calculation of reserve requirements was funded by a grant from the Advanced Research Projects Agency—Energy ("ARPA-E"), under which E3 worked closely with CAISO to compare the

¹⁹ E3, *Investigating the Economic Value of Flexible Solar Power Plant Operation*, Oct. 2018, available at <https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf>.

resulting outcomes against CAISO's incumbent methodology to calculate uncertainty reserves.²⁰

75. Q. CAN YOU PROVIDE AN EXAMPLE OF THE TYPES OF OUTPUTS PRODUCED BY THIS PROCESS?

A. Yes. By applying this methodology, E3 developed reserve requirements that vary on an hourly basis for each year of the planning horizon as a function of load, wind, and solar. Figure NS-8 summarizes those hourly outputs for 2025 for the Companies' projected demand forecast and existing portfolio of resources.

**FIGURE NS-8
EXAMPLE RESULTS OF AVERAGE UNCERTAINTY RESERVE REQUIREMENTS IN
2025 BY MONTH (COLUMNS) AND HOUR OF DAY (ROWS)**

	1	2	3	4	5	6	7	8	9	10	11	12
0	279	279	264	277	325	482	673	527	394	285	279	279
1	259	252	259	255	308	412	569	433	340	260	243	266
2	228	201	200	196	274	365	463	348	274	208	185	236
3	187	178	197	214	328	427	483	389	270	162	158	206
4	231	223	242	285	572	690	657	485	316	204	200	238
5	291	318	447	604	789	805	840	756	615	417	305	298
6	516	669	794	668	679	644	715	744	695	717	679	551
7	780	694	731	517	358	420	385	432	529	646	666	748
8	682	618	397	187	292	447	341	280	207	310	475	652
9	393	320	215	184	272	457	396	316	222	162	225	354
10	308	258	196	185	250	440	470	343	237	160	206	314
11	300	257	176	171	242	424	500	375	258	161	205	336
12	269	239	188	207	271	418	529	424	323	178	189	321
13	272	245	227	253	302	451	575	482	339	179	182	372
14	374	256	237	258	298	463	583	493	324	172	432	576
15	586	576	313	225	267	460	576	480	337	537	657	654
16	768	699	498	436	339	463	608	662	589	690	769	728
17	546	568	568	532	492	646	794	764	675	533	495	492
18	284	339	374	462	529	718	840	772	489	297	246	272
19	261	238	208	236	311	585	659	546	294	206	236	272
20	250	229	196	200	249	538	633	541	310	217	247	264
21	261	259	229	233	286	574	690	575	345	238	266	269
22	277	273	238	247	315	590	714	574	365	258	288	275
23	280	277	260	269	326	546	696	544	389	279	293	276

The uncertainty reserve requirements, which vary from hour to hour, exhibit several notable patterns on hourly and seasonal timescales:

²⁰ Journal of Renewable and Sustainable Energy, *Machine learning derived dynamic operating reserve requirements in high-renewable power systems*, Jun. 24, 2022, available at <https://www.ethree.com/wp-content/uploads/2023/03/Machine-learning-derived-dynamic-operating-reserve-requirements-in-high-renewable-power-systems.pdf>

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

- First, uncertainty reserve requirements tend to be higher in summer months than in other seasons; this is predominantly due to the fact that higher loads also typically result in higher absolute forecast uncertainties.
- Second, within each month, uncertainty reserves are typically highest in the early morning and late afternoon, corresponding to sunrise and sunset periods; this is due to the fact that forecast error for solar generation is typically highest when the sun is low on the horizon.

VI. CONCLUSION

76. Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

EXHIBIT SCHLAG-DIRECT-1

ENERGY AND ENVIRONMENTAL ECONOMICS, INC.
Partner

San Francisco, CA

Mr. Schlag has over 15 years of experience in energy analysis. He currently leads E3's Integrated System Planning practice area, where his principal areas of expertise are in resource adequacy & reliability, long-term electricity resource planning under deep decarbonization, and utility strategy. Mr. Schlag has led a number of E3's recent engagements to support utilities in their IRP analyses, including (1) Arizona Public Service, where E3 facilitated stakeholder workshops, provided independent modeling to provide stakeholders access to technical resources, and advised on the narrative development for the 2023 IRP; (2) Salt River Project, where E3 supported a first-of-its-kind integrated system planning process from conceptualization to completion; (3) Public Service Company of New Mexico, where Mr. Schlag provided strategic support to guide the development of the 2023 IRP, identifying resources needed to maintain near-term resource adequacy while positioning PNM for its eventual transition to a carbon-free electricity system; and (4) Xcel Energy, where E3 was asked to provide an independent third-party study of Xcel's long-term plan to decarbonize its electricity supply, an analysis that supported Xcel's recent decisions to commit to early coal plant retirement and nuclear relicensing. Mr. Schlag holds a Master of Science in Civil and Environmental Engineering (Atmosphere and Energy) and a Bachelor of Science in Earth Systems, both from Stanford University.

Mr. Schlag's previous clients include the Balancing Authority of Northern California, Bonneville Power Administration, the California Public Utilities Commission, the California Independent System Operator, Los Angeles Department of Water and Power, Portland General Electric, Public Generating Pool, Seattle City Light, Tucson Electric Power, the Western Electricity Coordinating Council, and the Western Interstate Energy Board. Select E3 projects include:

- **Arizona Public Service, Integrated Resource Planning Support, 2019-present.** Mr. Schlag led an engagement to provide strategic and technical support to APS culminating in the development of its 2020 Integrated Resource Plan. Mr. Schlag oversaw an effort to develop a simplified IRP portfolio model used to facilitate dialog with stakeholders through a series of workshops exploring the impacts of different potential future portfolios and ultimately presented key findings from the effort to the Arizona Corporation Commission. More recently, Mr. Schlag and the E3 team also provided support to APS to assist in the development of its 2023 IRP filing.
- **Salt River Project, Integrated System Plan Scoping & Support, 2021-present.** Mr. Schlag contributed to E3's efforts to support SRP in the initial scoping and development of an analysis plan for its inaugural Integrated System Plan (ISP), a broad effort to coordinate planning functions including integrated resource planning, transmission planning, distribution planning, and customer planning. Mr. Schlag led the development of a scenario analysis approach and also served as a lead liaison with the public advisory group of stakeholders.
- **NV Energy, Integrated Resource Planning Support, 2020-present.** Mr. Schlag has led multiple studies of resource adequacy for NV Energy using a loss-of-load-probability modeling framework. These studies include an analysis of the effective load carrying capability of renewables and

storage (filed in NV Energy's Fourth Amendment to the 2018 Joint IRP) and a quantification of the Planning Reserve Margin requirement needed to achieve a "one-day-in-ten-years" standard for resource adequacy (filed in NV Energy's 2021 Joint IRP). In support of both studies, Mr. Schlag provided expert testimony before the Public Utilities Commission of Nevada. Mr. Schlag has also overseen several studies examining the challenges NV Energy will face in its pursuit of the state's goal to decarbonize the electricity portfolio, including the development of cost-optimized portfolios to meet a range of levels of carbon reductions using the PLEXOS LT capacity expansion model. Mr. Schlag is currently supporting NV Energy with a study to update their PRM and ELCC assumptions for the 2024 Joint IRP.

- **Black Hills Energy, Colorado Electricity Resource Plan Support, 2020-present.** Mr. Schlag led E3's efforts to support Black Hills Energy through multiple phases of its 2022 Energy Resource Plan and Clean Energy Plan filings. In Phase 1, E3 conducted a number of analyses to inform the development of a long-term resource plan consistent with the state of Colorado's aggressive clean energy goals, including loss-of-load-probability modeling, capacity expansion modeling, and production simulation modeling. These plans were developed to meet (or exceed) requirements for 80% greenhouse gas emissions reductions by 2030 and 100% by 2050 and reflected Colorado's social costs of carbon and methane while maintaining system reliability. In Phase 2, E3 conducted detailed bid evaluation analysis using the same tools to support BHE in identifying specific projects to bring forward to the Commission for approval.
- **Public Service Company of New Mexico, Integrated Resource Planning Support, 2019-present.** Mr. Schlag has led E3's team in providing technical and strategic support to PNM through multiple IRP cycles and related processes. In 2020, Mr. Schlag led the development of the IRP report and narrative, which lays out a pathway for the utility to transition to 100% carbon-free energy by 2040. Subsequently, Mr. Schlag provided additional support PNM through a number of regulatory filings related to the IRP Action Plan, which included providing direct testimony regarding the implications of PNM's objective to achieve its goal of 100% carbon-free energy for its ability to maintain resource adequacy. In 2023, Mr. Schlag reprised his role in leading the development of the narrative for PNM's 2023 IRP, which focuses on identifying resources needed to maintain near-term resource adequacy while positioning PNM for its eventual transition to a carbon-free electricity system.
- **Pasadena Water & Power, System Planning Support, 2023-present.** In 2023, under Mr. Schlag's direction, E3 conducted an independent review of PWP's IRP modeling and narrative. Mr. Schlag presented results of this review, which found PWP's IRP to be generally aligned with industry standard practices, to Pasadena City Council at a public meeting. Subsequently, the City of Pasadena hired E3 to work with PWP to develop an Optimized Strategic Plan that would allow the city to meet its goal of sourcing all electricity from carbon-free sources by the end of 2030. Mr. Schlag is currently leading this study, which involves technical analysis of generation, transmission and distribution, and customer programs.
- **Various utilities, Southwest Resource Adequacy Study, 2021-2022.** Mr. Schlag led a study funded by a coalition of utilities to investigate resource adequacy challenges facing the Desert Southwest region in the coming decade; the study's sponsors included Arizona Public Service, Arizona Electric Power Cooperative, El Paso Electric, Public Service Company of New Mexico, Salt River Project, and Tucson Electric Power. The study used on state-of-the-art loss-of-load-probability modeling to assess reliability risks in light of rapidly growing loads, planned resource retirements, the transition towards renewables and storage, and increasing climatic uncertainty. The analysis highlighted a dire need for new capacity within the region to address a rapidly increasing shortfall and explored the possible roles of renewables, storage, and other resources to satisfy these needs.

- **Electric Reliability Council of Texas, Performance Credit Mechanism Implementation, 2023-present.** Mr. Schlag is currently advising E3's team in assisting ERCOT in efforts to implement a "Performance Credit Mechanism" (PCM) to improve system reliability in Texas. The PCM design, adopted by the Public Utilities Commission of Texas following an extensive market redesign process, represents an innovative market-based construct to provide financial incentives to generators to be available during periods of system scarcity. E3's advisory support in this effort spans all aspects of market design, including both technical and administrative elements of the design.
- **Public Utilities Commission of Texas, Assessment of Market Reform Options to Enhance Reliability of the ERCOT System, 2022-2023.** Mr. Schlag oversaw a study to analyze potential market reforms with the objective of improving the reliability of the ERCOT region. Using loss of load probability modeling, E3's analysis evaluated the impacts of various market reforms upon cost, reliability, and impacts on new investment. The study prompted the PUCT to recommend and ultimately adopt an innovative "Performance Credit Mechanism" (PCM) designed to reward generators for their ability to generate during the highest risk periods of the year, providing an additional economic incentive to encourage investment in the types of resources needed to ensure reliability.
- **Tucson Electric Power, Effective Load Carrying Capability Study of Renewables and Storage, 2022-2023.** Mr. Schlag led E3's study to calculate ELCCs for solar, wind, and energy storage to develop inputs for TEP's 2023 IRP. Using E3's RECAP loss-of-load-probability model, Mr. Schlag directed a team that examined how the marginal capacity value of different types of renewables and energy storage resources changed as a function of penetration. The results of E3's study served as direct inputs into TEP's 2023 IRP.
- **Arizona Electric Power Cooperative, Resource Adequacy Study, 2022.** Under Mr. Schlag's direction, E3 worked closely with AEPCO to apply LOLP modeling techniques to calculate a planning reserve margin requirement and effective load carrying capability values. E3 also worked closely with AEPCO to devise reasonable methods to apply the results of this analysis to its members in a manner that was both equitable and efficient given differences in load and electric resource portfolios.
- **California Energy Commission, SB100 Implementation Study, 2020.** Mr. Schlag contributed in an advisory capacity to the development of a study examining the investments needed to achieve a California's 100% goal for carbon-free power in 2050. The analysis builds off Mr. Schlag's prior experience working with California state agencies to develop an optimization-based approach to resource planning in the state using E3's RESOLVE model.
- **Xcel Energy, Upper Midwest Integrated Resource Plan Technical Support, 2018-2019.** Mr. Schlag led analysis of the impact of deep decarbonization scenarios on Xcel Energy's Upper Midwest System over the 2020-2034 planning period to support Xcel's IRP filing before the Minnesota Public Utilities Commission. Using E3's RESOLVE and RECAP models, Mr. Schlag identified optimal resource investment portfolios that met resource adequacy needs in the context of state and corporate long-term greenhouse gas reduction targets.
- **Sacramento Municipal Utilities District, Integrated Resource Planning Support, 2018-2023.** In a project evaluating long-term clean energy and greenhouse gas reduction goals in the context of vehicle and building electrification, Mr. Schlag customized E3's RESOLVE model to SMUD's system to develop optimal portfolios of renewable, conventional, and energy storage resources to meet SMUD's electric energy and reliability needs while achieving 90-100% carbon emissions reductions by 2040. More recently, Mr. Schlag directed technical analysis exploring various pathways to achieve a net-zero emissions target by 2030 in response to the SMUD Board's Climate

Emergency Declaration. The results of this analysis served as the basis for SMUD's recent 2030 Zero Carbon Plan.

- **California Public Utilities Commission, Integrated Resource Planning Implementation Support, 2016-present.** Mr. Schlag worked closely with the CPUC in its rollout of a framework and process for integrated resource planning. Mr. Schlag helped design the analytical framework currently in use in the 2017 IRP and managed an E3 team working to develop a "Preferred System Plan"—an optimal resource portfolio consistent with the state of California's long-term greenhouse gas reduction goals—using RESOLVE, E3's in-house capacity expansion model designed for use on high-penetration renewable systems. Mr. Schlag continues to advise E3's team in an ongoing engagement to provide technical support to the IRP process.
- **Public Generating Pool, Pacific Northwest Low Carbon Scenario Analysis, 2017.** Mr. Schlag led a study examining the most effective policy mechanisms to facilitate greenhouse gas reductions in the electric sector in the Pacific Northwest. The study relied on E3's RESOLVE model to compare the relative impacts of expanded RPS goals, carbon caps, carbon taxes, and a prohibition on new gas generation, highlighting the different cost and emissions impacts of each on ratepayers in the Northwest.
- **Los Angeles Department of Water and Power, 100% Clean Energy Study, 2017.** Working directly with LADWP staff, Mr. Schlag designed a work plan for LADWP's 100% Clean Energy Study to be executed over a period of several years. This effort included scoping of a public outreach program, development of potential research partnerships, and preliminary data gathering and validation.
- **California Public Utilities Commission, RPS Program Evaluation Support, 2012-2017.** Mr. Schlag managed an E3 team including four subcontractors to provide multiple services to the CPUC over a five-year period. Foremost among these was the redesign, development, and maintenance of an updated RPS Calculator—tailored specifically to highlight renewable integration challenges at high penetrations—which was used as a key source of inputs in both the CAISO's Transmission Planning Process (TPP) and the CPUC's Long-Term Procurement Proceeding (LTPP). Additional support tasks included development and maintenance of a database of the renewable contracts of the three investor-owned utilities and an assessment of renewable cost, potential, and performance in California and throughout the Western U.S.
- **Northwestern Energy, EIM Benefits Analysis, 2016-2017.** Mr. Schlag led E3's study of the benefits to NWE of participating in the Western EIM. The E3 team worked closely NWE staff to model the effect of NWE's EIM participation on system operations using PLEXOS production simulation software, providing a clear illustration of the EIM value proposition.
- **Balancing Authority of Northern California, EIM Benefits Analysis, 2016.** Mr. Schlag led E3's study of the benefits to BANC members of participating in the Western EIM. The E3 team worked closely with representatives from all BANC members to model the operations of their respective electric systems accurately using PLEXOS production simulation software, providing a clear illustration of the EIM value proposition for each BANC member.
- **Seattle City Light, EIM Benefits Analysis, 2016.** Mr. Schlag led the assessment of Seattle City Light's prospective benefits of participation in the Western EIM. E3's analysis for SCL was designed specifically to highlight the value of Seattle's flexible hydroelectric generation fleet in the EIM's 15- and 5-minute markets, using dispatch optimization software and historical market prices to quantify the value of arbitrage opportunities.
- **California Independent System Operator, SB350 Regionalization Study, 2015-2016.** Mr. Schlag contributed to E3's work as part of a consulting team studying the benefits of expanding the CAISO to a broader regional entity in accordance with California's Senate Bill 350. Using RESOLVE, Nick helped to design the alternative portfolios used as the basis for identifying the potential infrastructure impacts (and associated fixed cost savings) of ISO expansion.

- **Western Electricity Coordinating Council & Western Interstate Energy Board, Western Interconnection Flexibility Assessment, 2014-2016.** Working in partnership with the National Renewable Energy Laboratory, an E3 team managed by Mr. Schlag completed a thorough examination of the flexibility of the generation fleet of the Western Interconnection and its ability to integrate high penetrations of renewable generation. The study identified both operational challenges as well as institutional and physical solutions to facilitate renewable integration across the region.
- **Western Interstate Energy Board, Western Gas-Electric Study, 2013-2014.** Mr. Schlag managed a two-phase study of gas-electric coordination in the Western Interconnection to investigate whether the natural gas infrastructure in the West would be sufficient to meet future needs of the electric sector, considering both the anticipated retirements of a sizeable portion of the Western coal fleet as well as the increasing penetrations of intermittent renewable resources.
- **PG&E, SCE, SDG&E, LADWP & SMUD, Investigating a Higher Renewables Portfolio Standard for California, 2013.** As part of the E3 team, Mr. Schlag helped to design and analyze a range of renewable portfolios to meet a 50% Renewables Portfolio Standard, using production simulation to evaluate integration challenges and calculating the corresponding rate impacts for California ratepayers.
- **Portland General Electric, Low Carbon Portfolio Development, 2012.** Mr. Schlag worked with PGE staff and a group of environmental stakeholders to create a low carbon portfolio for analysis in PGE's 2012 Integrated Resource Plan. The portfolio was designed to include higher penetrations of renewable generation and accelerated achievement of efficiency goals.
- **Western Electricity Coordinating Council, Cost and Performance Review of Generation Technologies, 2012.** Mr. Schlag led E3's literature review of the cost and performance of new electric generation technologies, which culminated in a report to WECC staff with recommended assumptions for use in its 10- and 20-year study processes.

STANFORD UNIVERSITY

Teaching Assistant

Palo Alto, CA

2008-2009

- Assisted students with coursework in engineering classes related to energy efficiency, electric power, and meteorology; facilitated students' experiments in the Renewable Energy Laboratory

ROCKY MOUNTAIN INSTITUTE

MAP Sustainable Energy Fellow

Boulder, CO

Summer 2008

- Awarded three-month MAP Sustainable Energy Fellowship sponsored by MAP Royalty, Inc. to conduct research on the energy efficiency potential in residential, commercial, and industrial sectors of the United States as part of RMI's Next Generation Utilities project

STOCKHOLM ENVIRONMENT INSTITUTE

Donald Kennedy Environmental Fellow

Stockholm, Sweden

Summer 2007

- Awarded Donald Kennedy Environmental Fellowship through Stanford in Government to study benefits of clean cooking fuels in Sub-Saharan Africa, research that culminated with a working paper on the market barriers to clean cooking fuel adoption

Education

Stanford University
M.S., Atmosphere and Energy (Civil & Environmental Engineering)

Palo Alto, CA
2009

Stanford University
B.A., Earth Systems (Energy Science and Technology)

Palo Alto, CA
2008

Expert Witness Testimony

1. *Public Utilities Commission of Nevada, 2020, testified on behalf of NV Energy in its Fourth Amendment to 2018 Joint Triennial Integrated Resource Plan proceeding regarding the effective load carrying capability (ELCC) of renewable and energy storage resources and the value of diverse renewable resources in helping NV Energy meet Nevada's goal of 100 percent zero-carbon energy by 2050*
2. *Public Utilities Commission of Nevada, 2021, testified on behalf of NV Energy in its 2021 Joint Triennial Integrated Resource Plan to support an update to NV Energy's Planning Reserve Margin (PRM) requirement based on a loss of load probability analysis to identify the amount of capacity needed to meet a "one-day-in-ten-years" standard*
3. *New Mexico Public Regulation Commission, 2021, testified on behalf of Public Service Company of New Mexico in the company's filing for the abandonment and replacement of leased shares of the Palo Verde Nuclear Generating Station regarding best practices in planning for resource adequacy and the challenges that the company will face in its transition to 100 percent carbon-free energy*
4. *Colorado Public Utilities Commission, 2021-2022, testified on behalf of Black Hills Energy in its Clean Energy Plan (CEP) filing as a technical expert supporting analysis of the utility's future resource adequacy needs and optimization of portfolios to meet the greenhouse gas reduction targets of 80% below 1990 levels by 2030 and 100% clean energy by 2050*
5. *Public Utilities Commission of Nevada, 2023, testified on behalf of NV Energy in the Fifth Amendment to the 2021 Joint IRP supporting NV Energy's continued use of E3's PRM and ELCC analysis and providing commentary on evolving risks related to resource adequacy in the Western Interconnection*

Publications

1. Burdick, A., **N. Schlag**, A. Au, R. Go, Z. Ming, & A. Olson (2022). "Lighting a Reliable Path to 100% Clean Electricity." IEEE Power and Energy Magazine, 20(4):30-43.
2. Stenclik, D., M. Ahlstrom, S. Awara, J. Bakke, A. Bloom, W. Cole, E. Delaney, A. Dobbie, S. Elsevier, A. Acevedo, B. Frew, E. Hart, W. Henson, E. Ibanez, J. Jin, W. Lamanna, C. Lau, J. Matevosyan, M. Milligan, K. Parks, R. Pungaliya, **N. Schlag**, J. Sharp, E. Smeloff, G. Stephen, A. Tuohy, M. Welch, P. Wong (2023). Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation. A

Report of the Redefining Resource Adequacy Task Force. Reston, VA.
<https://www.esig.energy/new-design-principles-for-capacity-accreditation>.

3. Stenclik, D., A. Bloom, W. Cole, G. Stephen, A. Acevedo, R. Gramlich, C. Dent, **N. Schlag**, & M. Milligan (2021). "Quantifying Risk in an Uncertain Future: The Evolution of Resource Adequacy," IEEE Power and Energy Magazine, 19(6): 29-36.
4. **Schlag, N.**, Z. Ming, A. Olson, L. Alagappan, B. Carron, K. Steinberger, & H. Jiang (2020). "Capacity and Reliability Planning in the Era of Decarbonization." <https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf>.
5. **Schlag, N.**, Z. Ming, & A. Olson (September 2020). "Adding it all up: Counting the capacity contribution of variable and duration limited resources." Utility Dive. [https://www.utilitydive.com/news/adding-it-all-up-counting-the-capacity-contribution-ofvariable-and-durati/584843/](https://www.utilitydive.com/news/adding-it-all-up-counting-the-capacity-contribution-of-variable-and-durati/584843/).
6. **Schlag, N.**, D. Mullen, & K. Patel. (April 2019). "Moving beyond 'rules of thumb' for smart, cost-effective storage deployment." Utility Dive. <https://www.utilitydive.com/news/moving-beyond-rules-of-thumb-for-smart-cost-effective-storage-deployment/553674/>.
7. Woo, C.K., Y. Chen, A. Olson, J. Moore, **N. Schlag**, A. Ong, & T. Ho. (2017). "Electricity price behavior and carbon trading: New evidence from California," Applied Energy, Elsevier, vol. 204(C): 531-543.
8. Olson, A., C.K. Woo, **N. Schlag** & A. Ong (2016). "What Happens in California Does Not Always Stay in California: The Effect of California's Cap-and-Trade Program on Wholesale Electricity Prices in the Western Interconnection," The Electricity Journal, 29(7), 18-22.
9. Olson, A., E. Hart, J. Hargreaves, R. Jones, **N. Schlag**, G. Kwok, N. Ryan, R. Orans, & R. Frowd, "Halfway There: Can California Achieve a 50% Renewable Grid?", IEEE Power and Energy Magazine, 13(4): 41-52.
10. Woo, C.K., H. Liu, F. Kahrl, **N. Schlag**, J. Moore, & A. Olson (2012). "Assessing the economic value of transmission in Alberta's restructured electricity market." Electricity Journal, 25(3): 68-80.

AFFIRMATION

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

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

Date: May 31, 2024



NICOLAI SCHLAG

DAVID HARRISON

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2024 Joint Integrated Resource Plan (2025-2044)

Docket No. 24-05 _____

Prepared Direct Testimony of

David Harrison

I. INTRODUCTION

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

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

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

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

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

I earlier served as a Senior Economist at the President's Council of Economic Advisors, where my areas of responsibility included energy and environment, natural resources, occupational health and safety, and transportation. I also previously worked at the U.S. Department of Transportation, the U.S. Department of Housing and Urban Development, and the National Bureau of Economic Research.

My background includes extensive experience related to benefit-cost analysis, particularly as it relates to environmental regulation, as well as to climate change policy and economic impact assessment. My specific experience related to assessing environmental costs and economic impacts related to integrated resource plans ("IRPs") in Nevada began in 1993, when I directed two studies to evaluate

the external costs of electric utility resource selection, one in southern Nevada and one in northern Nevada on behalf of Nevada Power and Sierra, respectively. In most years since 2006, I have directed studies to evaluate the environmental costs and economic impacts of the Companies' IRPs and related IRP amendments. My full curriculum vita is provided in **Exhibit Harrison-Direct-1**.

II. TESTIMONY OBJECTIVES

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

A. I have been asked by the Companies to offer my expert opinion in six areas related to the environmental costs and economic impacts of the four resource plans that are included in the 2024 Joint Integrated Resource Plan ("2024 IRP"): (1) national policy regarding carbon dioxide ("CO₂") emissions from power plants as well as the potential impacts of CO₂ policy on the prices of fossil fuels used by the Companies; (2) external environmental costs for conventional and toxic air emissions; (3) external environmental costs based on monetary estimates of the social cost of carbon ("SCC") for CO₂ emissions as required by the August 2018 Order of the Commission in Docket No. 17-07020 to implement Senate Bill 65 (2017) ("August 2018 Order"); (4) external environmental costs of the Companies' water consumption, based upon the value of water use that is not included in the Present Worth Revenue Requirement ("PWRR") for the resource plans; (5) qualitative assessments of the potential external environmental costs for land use as well as other potential environmental costs not included in the above categories; and (6) the net economic benefits (i.e., economic impacts) to the Nevada economy. I also provide a summary of conclusions regarding the analyses, including information on the implications of my environmental cost estimates for the Present Worth of Social Costs ("PWSC"), which are equal to the sum of PWRR and

environmental costs that are not internalized as private costs to the Companies. The results of my analyses are discussed in detail in a report I prepared in collaboration with NERA colleagues (“NERA Report”), which is provided in Technical Appendix Item ECON-9.

4. Q. PLEASE INDICATE HOW YOUR TESTIMONY RELATES TO THE REQUIREMENTS FOR IRP SUBMISSIONS.

A. My testimony relates to two major categories of IRP requirements, one related to assessing environmental costs of alternative plans and one related to assessing the “net economic benefits” of alternative plans. The Nevada Administrative Code (“NAC”) requires Nevada electric utilities to rank their plans on the basis of the PWRR and the PWSC. As noted, the PWSC of a resource plan is defined as the sum of the PWRR plus “environmental costs that are not internalized as private costs to the utility.”¹ Environmental costs are defined by the Commission as “costs, wherever they may occur, that result from harm or risks of harm to the environment after the application of all mitigation measures required by existing environmental regulation or otherwise included in the resource plan.”² The environmental costs “must be quantified for air emissions, water and land use.”³

Section 704.9357 of the NAC requires the Companies to assess the “net economic benefits” of resource plans reflecting “both the positive and negative changes.” Section 704.9357 of the NAC specifies that positive changes to be calculated include in-state expenditures related to capital, supplies, wages, fees, and taxes associated with the resource plans. Greater expenditures would produce positive

¹ NAC § 704.937

² NAC § 704.9359

³ *Id.*

economic impacts. The regulation does not include any specific language on how to assess the potential negative impacts of higher electricity rates.

5. **Q. PLEASE PROVIDE AN OVERVIEW OF THE 2024 IRP PLANS AND THE MAJOR ELEMENTS THAT DIFFERENTIATE THEM.**

- A. The 2024 IRP includes four alternative resource plans for meeting electricity demand and state renewable energy requirements over the 26 year period from 2025 to 2050 as well as a Base Case used in the economic impact analysis. Each plan meets or exceeds the current Renewable Portfolio Standard (“RPS”) as well as anticipated customer Nevada Green Rider (“NGR”) participation and the 12.5 percent unforced capacity planning reserve margin (“UCAP PRM”) for each utility, targets the Companies’ proportionate contribution to the state’s 2050 clean energy goal, and includes most of the same generation and transmission resources.

The following are the four 2024 IRP resource plans and the Base Case used in the economic impact assessments and information on the major identified planned resources that differ in the Base Case and the resource plans.

- **Base Case.** This plan starts with the approvals from the Fifth Amendment to the 2021 IRP, including repower of Valmy units with natural gas after the summer of 2025, the Sierra Solar 400 MW joint photovoltaic (“PV”) and Battery Energy Storage System (“BESS”) project, and continued operation of Tracy 4/5.
- **Balanced Plan (Preferred Plan).** This plan includes all the projects included in the Base Case and adds: (a) Dry Lake East, a 200 MW paired PV/BESS for NPC; (b) Boulder Solar III, a 128 MW paired PV/BESS for Nevada Power; (c) Libra, a 700 MW paired PV/BESS for Nevada Power;

and (d) new natural gas combustion turbine (“CT”) units at Valmy with a combined capacity of 411 MW for Sierra.

- **Renewable Plan (Alternative Plan).** This plan includes all the projects included in the Base Case and adds: (a) Dry Lake East, a 200 MW paired PV/BESS for Nevada Power; (b) Boulder Solar III, a 128 MW paired PV/BESS for NPC; and (c) Libra, a 700 MW paired PV/BESS split between Nevada Power and Sierra. That is, this plan includes the proposed projects included in the Balanced Plan except for the Valmy CTs and with split ownership of the Libra PV/BESS. The lack of the Valmy CT units means that there are added placeholder BESS units to achieve capacity requirements in the Renewable Plan.
- **No Open Position Plan.** This plan includes all the projects included in the Base Case and adds: (a) Dry Lake East, a 200 MW paired PV/BESS for NPC; (b) Boulder Solar III, a 128 MW paired PV/BESS for Nevada Power; (c) Libra, a 700 MW paired PV/BESS for NPC; (d) new CT units at Valmy with a combined capacity of 411 MW for SPPC; and (e) new CT units at Harry Allen with a combined capacity of 445 MW for Nevada Power. That is, this plan includes the same proposed projects as included in the Balanced Plan as well as new CT units at Harry Allen. In accordance with statutory requirements to evaluate such a plan, this plan also includes substantial additional capacity from company-owned or contracted resources to close the companies’ open positions as soon as possible, with a significant share to be company-owned renewable and storage resources.
- **Low Carbon Plan.** This plan includes all the projects included in the Base Case and adds: (a) Dry Lake East, a 200 MW paired PV/BESS for Nevada Power; (b) Boulder Solar III, a 128 MW paired PV/BESS for Nevada

Power; and (c) Libra, a 700 MW paired PV/BESS for Nevada Power. That is, this plan includes the same proposed projects as included in the Balanced Plan except for the Valmy CTs. In accordance with statutory requirements to evaluate such a plan, this plan also includes additional renewables capacity to meet an 80 percent reduction in CO₂ emissions by 2030 relative to 2005.

III. CO₂ POLICY SCENARIOS

6. **Q. PLEASE SUMMARIZE THE CO₂ POLICY SCENARIOS YOU HAVE DEVELOPED.**

A. I developed three CO₂ policy scenarios to reflect uncertainty regarding how the major current federal climate policies affecting the electric power sector—various tax credit subsidy programs and related programs included in the Inflation Reduction Act (“IRA”) passed by Congress and signed by President Biden in August 2022—will affect fossil fuel prices. These IRA provisions do not impose a “price” on CO₂ emissions from power plants as would a cap-and-trade program if it were implemented under Section 111(d) of the Clean Air Act, which was the basic policy assumption included in my assessments of federal climate policy before the Fourth Amendment to the 2021 IRP. That policy assumption is no longer appropriate because on June 30, 2022, the Supreme Court ruled that Section 111(d) does not provide the U.S. Environmental Protection Agency (“EPA”) with the authority to regulate emissions based on “generation shifting” as would occur under a cap-and-trade program. The various tax credit programs and related programs in the IRA impact fossil fuel prices through effects on the demands for various types of electricity energy sources and overall energy use and corresponding effects on the demands for natural gas and coal.

While many provisions of the IRA could have some effect on natural gas and coal prices, the largest effects are likely to be due to the large tax credit programs for renewable and clean energy for new electric generation facilities and for generation from existing merchant nuclear units. The IRA provides for renewable production tax credits (“PTC”) and investment tax credits (“ITC”) for projects put into service by the end of 2024 and for replacement of these programs with “technology-neutral” clean energy subsidies for projects put into service from 2025 to 2035. The IRA provides a PTC for existing merchant nuclear units (i.e. units not owned/operated by regulated utilities) for generation from January 1, 2024, to December 31, 2032. I model the effects of these IRA provisions as well as IRA effects on overall electricity demand and IRA effects on the export of liquified natural gas (“LNG”).

The three federal climate policy scenarios reflect a range of potential effects of these IRA programs on fossil fuel prices. I refer to these as the Low CO₂ Policy scenario, the Mid CO₂ Policy scenario, and the High CO₂ Policy scenario.

7. Q. WHICH CO₂ POLICY SCENARIO DO YOU USE FOR PURPOSES OF YOUR TESTIMONY?

A. I use the Mid CO₂ Policy scenario for the analyses reported in my testimony and in the NERA Report. As noted, this scenario assumes that there will be no “price” on electric sector carbon emissions and that CO₂ emissions in the 2024 IRP cases will be affected by federal climate policy through effects of the Mid CO₂ Policy scenario on fossil fuel prices.

8. **Q. HOW DID YOU DEVELOP YOUR ESTIMATES OF THE EFFECTS OF THE CO₂ POLICY SCENARIOS ON FOSSIL FUEL PRICES?**

A. I developed estimates of the effects of the CO₂ policy scenarios on fossil fuel prices by developing assumptions on the implementation of the relevant IRA provisions and using the N_{ew}ERA model to estimate impacts on Henry Hub natural gas prices and on the coal prices that are relevant to the Companies. N_{ew}ERA is a model developed and maintained by NERA that includes a detailed electric sector model and related integrated fuel price and macroeconomic models. With the exception of the effect of the IRA on LNG exports, these IRA provisions lead to likely decreases in the demands for fossil fuels. These decreases in demands for fossil fuels are likely to result in decreases in the prices for natural gas and coal, with the size of the likely decreases dependent upon the size of the various tax credit subsidies, the supply and demand elasticities for the fossil fuels, and other factors. The NERA Report provides information on the specific methodology used to develop assessments of the fossil fuel price effects of the three climate policy scenarios.

9. **Q. PLEASE EXPLAIN HOW THE CO₂ POLICY SCENARIOS AFFECT NV ENERGY'S MODELING OF ITS 2024 IRP PLANS.**

A. The estimates of fuel price changes due to the three federal climate policy scenarios were incorporated into the Companies' PLEXOS runs as changes in fossil fuel prices and thus in changes in the costs to dispatch fossil-fuel generating units. Thus, the changes in fuel prices affect the estimated generation of various units under the 2024 IRP plans. As noted, the results in my testimony and the NERA Report are based on the Mid CO₂ Policy scenario. I use the Companies' PLEXOS projections that incorporate the Mid CO₂ Policy scenario along with other information to develop estimates of the environmental costs of the 2024 IRP plans—including

environmental costs related to conventional and toxic air emissions and to CO₂ emissions as well as external costs of water use—and to develop estimates of the impacts of the 2024 IRP plans on the Nevada economy.

IV. ENVIRONMENTAL COSTS FOR CONVENTIONAL AND TOXIC AIR EMISSIONS

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

A. I applied a “damage-function” framework to evaluate the environmental costs of conventional and toxic air emissions for which sufficient data were available to estimate the potential damages related to health effects. The specific emissions in this group include nitrogen oxides (“NO_x”), volatile organic compounds (“VOC”), particulate matter (“PM”), mercury, and sulfur dioxide (“SO₂”). The national SO₂ cap set in the Acid Rain Trading Program is not expected to be binding—with allowance prices expected to be zero or close to zero—and, thus, SO₂ emissions are evaluated based on damage values rather than as covered by a binding cap-and-trade program as was appropriate in some earlier IRP analyses. The damage-function approach is a standard economic approach for assessing the environmental costs of air emissions when emissions are not capped. The damage values that I used for these emissions are primarily based on health effects associated with ambient PM (which depend on NO_x emissions and SO₂ emissions that operate as precursors for PM as well as on emitted PM) and ground-level ozone (which is formed by NO_x and VOC emissions in the presence of sunlight), as described in the NERA Report. To develop this information, I relied on data and methodologies developed and used by the EPA as well as other information. I also estimated

1 damage values for mercury from information developed by the EPA in its
2 assessments of the final Mercury and Air Toxics Standards (“MATS”) rule. As in
3 prior assessments, I did not assess the validity of the EPA information used in these
4 calculations.

5
6 **11. Q. PLEASE SUMMARIZE OTHER SOURCES OF INFORMATION YOU**
7 **USED TO DEVELOP THESE ENVIRONMENTAL COST ASSESSMENTS.**

8 A. I relied on information provided by the Companies regarding the various resource
9 plans. This information includes emission rates for the relevant facilities, estimated
10 annual generation and heat input for relevant facilities (based on the PLEXOS
11 dispatch modeling results), and other information as described in the NERA Report.
12 The information provided by the Companies relates to both Nevada Power and
13 Sierra, because the two systems were modeled jointly, and thus the resource plans
14 involve emissions related to both the Nevada Power and Sierra systems. I
15 supplemented the information from the Companies with relevant information from
16 public sources; for example, as noted above, in estimating health effects and dollar
17 values for various emissions, I relied on data and methodologies developed by the
18 EPA.

19
20 **12. Q. PLEASE SUMMARIZE YOUR ESTIMATES OF THE ENVIRONMENTAL**
21 **COSTS OF CONVENTIONAL AND TOXIC AIR EMISSIONS FOR THE**
22 **2024 IRP PLANS.**

23 A. **Table Harrison Direct-1** presents the estimated environmental costs related to
24 conventional and toxic air emissions for the 2024 IRP plans. The table includes
25 costs for emissions related to ambient pollutants subject to the National Ambient
26 Air Quality Standards (“NAAQS”) and the MATS rule. Based on the NAAQS, I
27

1 have included emissions of NO_x, VOC, PM, carbon monoxide (“CO”), and SO₂.
2 Damage values for VOC emissions are zero because air quality modeling results
3 indicate that, given ambient climatic conditions, changes in VOC emissions do not
4 affect ozone concentrations in Nevada (which are driven at the margin by NO_x
5 emissions). CO is not monetized because the required air quality modeling data are
6 not available, although CO emissions estimates are provided in the NERA Report.
7 Based on their inclusion in the MATS rule, emissions of mercury and hydrogen
8 chloride (“HCl”) are also included. HCl is not monetized because the EPA did not
9 develop the relevant information in the MATS regulatory impact analysis;
10 however, HCl emission projections are provided in the NERA Report. Note that the
11 MATS rule uses PM emissions as a proxy for non-mercury metallic air toxics;
12 however, since PM emissions are included based upon the NAAQS, this element
13 of the MATS rule does not lead to estimates of additional environmental costs. The
14 NERA Report provides additional information on the methods used to develop
15 environmental costs for these pollutants. I do not expect that including
16 environmental costs for other pollutants, if they could be estimated, would have
17 any significant effect on my estimates of the environmental costs of conventional
18 and toxic air emissions.

19
20
21
22
23
24 ///

25 ///

26 ///

Table Harrison Direct-1. Present Values of Environmental Costs for Conventional and Toxic Air Emissions, 2025-2050 (2025\$ Millions)

	Balanced	Renewable	No Open Position	Low Carbon
NO _x	\$2.60	\$2.55	\$2.49	\$1.76
PM	\$89.22	\$86.55	\$93.11	\$57.09
VOC	\$0.00	\$0.00	\$0.00	\$0.00
CO	--	--	--	--
SO ₂	\$6.05	\$5.91	\$6.31	\$3.99
Mercury	\$0.00	\$0.00	\$0.00	\$0.00
HCl	--	--	--	--
Total	\$97.87	\$95.01	\$101.91	\$62.85

Notes: All values are present values as of 2025 in millions of 2025 dollars for the period 2025-2050 using inflation rate information provided by the Companies and nominal annual discount rates of 7.43 percent for Nevada Power and 6.95 percent for Sierra. Total may differ from the sum of the rows due to independent rounding. "--" denotes that the environmental costs of the air emissions are not monetized. The costs of VOC emissions are zero because of evidence that these emissions do not contribute to urban ozone, the relevant damage category. The costs of mercury emissions are non-zero but round to \$0.00 in millions for all four plans.

Source: NERA calculations as explained in text.

13. Q. PLEASE COMMENT ON THE DIFFERENCES IN ENVIRONMENTAL COSTS RELATED TO CONVENTIONAL AND TOXIC AIR EMISSIONS FOR THE OTHER 2024 IRP PLANS RELATIVE TO THE BALANCED PLAN, THE PREFERRED PLAN.

A. **Table Harrison Direct-2** provides estimates of the differences in environmental costs related to conventional and toxic air emissions for the other 2024 IPR plans compared to the Balanced Plan, the Preferred Plan. Compared to the Balanced Plan (Preferred Plan), the Renewable Plan has lower costs (less than 3 percent), the No Open Position Plan has greater costs (about 4 percent) and the Low Carbon Plan has lower costs (about 36 percent).

Table Harrison Direct-2. Differences in Present Values of Environmental Costs of Conventional and Toxic Air Emissions Relative to the Balanced Plan (Preferred Plan), 2025-2050 (2025\$ Millions)

	Balanced	Renewable	No Open Position	Low Carbon
NOx	--	-\$0.05	-\$0.11	-\$0.84
PM	--	-\$2.68	\$3.88	-\$32.13
VOC	--	\$0.00	\$0.00	\$0.00
CO	--	--	--	--
SO2	--	-\$0.14	\$0.26	-\$2.05
Mercury	--	\$0.00	\$0.00	\$0.00
HCl	--	--	--	--
Total	--	-\$2.87	\$4.03	-\$35.03

Notes: All values are present values as of 2025 in millions of 2025 dollars for the period 2025-2050 using inflation rate information provided by the Companies and nominal annual discount rates of 7.43 percent for Nevada Power and 6.95 percent for Sierra. Total may differ from the sum of the rows due to independent rounding.

Source: NERA calculations as explained in text.

In addition to the potential health costs associated with conventional and toxic air emissions, there are also potential non-health costs. As noted in the NERA Report, non-health damages are expected to be small relative to the health damages, and thus I would not expect their omission to have a major effect on the environmental cost results, particularly the comparative results for the alternative 2024 IRP plans.

V. SOCIAL COSTS OF CARBON FOR CO2 EMISSIONS

14. Q. PLEASE DESCRIBE THE METHODOLOGY YOU USED TO DEVELOP ESTIMATES OF THE SOCIAL COST OF CARBON FOR CO₂ EMISSIONS.

A. The August 2018 Order requires that environmental costs include estimates of the “social cost of carbon” and prescribes a methodology for its calculation. The regulations state that “environmental costs to the State associated with operating and maintaining a supply plan or demand-side plan must be quantified for air

emissions, water and land use and the social cost of carbon as calculated pursuant to [NAC § 704.937(5)].”⁴ The analyses I developed comply with these regulatory requirements.

I developed estimates of CO₂ emissions over the course of the 26-year period from 2025 to 2050 under the 2024 IRP plans using information from modeling done by the Companies and from other sources. The NERA Report provides information on the trajectories of CO₂ emissions for the 2024 IRP plans and on the differences in emissions trajectories between the other plans and the Balanced (Preferred Plan).

Subsection 5 of the August 2018 Order requires the following determination of the social cost of carbon. “[T]he social cost of carbon must be determined by subtracting the costs associated with emissions of carbon internalized as private costs to the utility pursuant to subsection 3 from the net present value of the future global economic costs resulting from the emission of each additional metric ton of CO₂. The net present value of the future global economic costs resulting from the emission of an additional ton of CO₂ must be calculated using the best available science and economics such as the analysis set forth in the ‘Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis’ released by the Interagency Working Group on Social Cost of Greenhouse Gases in August 2016.”⁵ As discussed in the NERA Report, I used the

⁴ NAC § 704.9359.

⁵ There is some potential confusion in use of the term “social cost of carbon.” The term is used by the Interagency Working Group, as well as many commentators, to refer to estimates of the present value of the future global economic cost of an additional ton of CO₂ emissions emitted in a given year. In contrast, the Commission in its August 2018 Order refers to the “social cost of carbon” as the *difference* between this present value and the costs internalized as private costs. NERA adopts the terminology of the August 2018 Order in its current report (although its previous reports have used “social cost of carbon” to refer to the values developed by the Interagency Working Group). The NERA Report provides information on the methodology used by the Interagency Working Group to

most recent estimates of the Interagency Working Group that were provided in February 2021.

The Interagency Working Group provides estimates of the present value of future global economic costs from an additional ton of CO₂ emitted in a given year for three discount rates—2.5 percent, 3 percent, and 5 percent—using the averages of the damages distributions it calculated from modeling results. It also provides a fourth set of global economic costs based on the 3 percent discount rate and the 95th percentile of the damages distribution, which it notes are designed to represent economic impacts from temperature change further out in the tails of the global economic cost distribution. These four sets of annual values for global economic costs from an additional ton of CO₂ cover a very large range and, indeed, the full range of values reported by the Interagency Working Group is much greater than these four sets of estimates.

Because the carbon policy scenarios I use do not result in internalization of any environmental costs related to CO₂ emissions as private costs—as would occur under a cap-and-trade program—I used the values provided by the Interagency Working Group in their February 2021 report as the social cost of carbon for a ton of CO₂ emitted in each year.⁶

develop its estimates and on the wide range of estimates that are provided in the February 2021 interim report, which updates the results from the August 2016 report for inflation.

⁶ In the regulatory impact analysis of the Agency’s Final Rulemaking, “Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,” the EPA estimated climate change benefits using a new set of values for the Social Cost of Carbon. See U.S. Environmental Protection Agency, “*Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*,” Dec. 2, 2023, available at <https://www.epa.gov/environmental-economics/scghg>. Although these values have undergone review by the EPA, this revised set of values has not been reviewed by the Interagency Working Group.

15. Q. PLEASE SUMMARIZE YOUR ESTIMATES OF THE SOCIAL COSTS OF CARBON FOR 2024 IRP PLANS.

A. Table Harrison Direct-3 shows the social cost of carbon (as present values) for the 2024 IRP plans using the 3 percent discount rate and average damage values for future global economic costs. Results using the other three Interagency Working Group sets of values are provided in an Appendix to the NERA Report.

Table Harrison Direct-3. Present Values of Social Costs of Carbon, 2025-2050 (2025\$ Millions)

Balanced	Renewable	No Open Position	Low Carbon
\$9,997	\$9,933	\$10,047	\$6,825

Notes: All values are present values as of 2025 in millions of 2025 dollars for the period 2025-2050 using the social cost of carbon values from the Interagency Working Group based upon a 3 percent discount rate and the average damages distribution.

Source: NERA calculations as explained in text.

16. Q. PLEASE COMMENT ON THE DIFFERENCES IN THE SOCIAL COSTS OF CARBON FOR THE OTHER 2024 IRP PLANS RELATIVE TO THE BALANCED PLAN, THE PREFERRED PLAN.

A. Table Harrison Direct-4 shows the social cost of carbon for the other 2024 IRP plans relative to the Balanced Plan, the Preferred Plan. Compared to the Balanced Plan (Preferred Plan), the costs of CO₂ emissions are slightly lower in the Renewable Plan, slightly larger in the No Open Position Plan, and much lower in the Low Carbon Plan.

Table Harrison Direct-4. Differences in Present Values of Social Costs of Carbon for Other 2024 IRP Plans Relative to the Balanced Plan (Preferred Plan), 2025-2050 (2025\$ Millions)

Balanced	Renewable	No Open Position	Low Carbon
-	-\$64	\$50	-\$3,172

Note: All values are present values as of 2025 in millions of 2025 dollars for the period 2025-2050 using the social cost of carbon values from the Interagency Working Group based upon a 3 percent discount rate and the average damages distribution.

Source: NERA calculations as explained in text.

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

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

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

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

A. I estimated the potential external environmental costs of water use based upon the value of water use that is not included in the PWRR using plant-specific

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

19. Q. PLEASE SUMMARIZE YOUR ESTIMATES OF THE EXTERNAL COSTS OF WATER USE FOR THE 2024 IRP PLANS.

A. **Table Harrison Direct-5** shows the estimated external costs of water use. External water costs represent the opportunity costs of water consumed at the various plants owned by NV Energy that are included in the PWRR.

Table Harrison Direct-5. Present Values of External Water Costs, 2025-2050 (2025\$ Millions)

Balanced	Renewable	No Open Position	Low Carbon
\$12.88	\$16.70	\$12.75	\$14.65

Notes: All values are present values as of 2025 in millions of 2025 dollars for the period 2025-2050 using inflation rate information provided by the Companies and nominal annual discount rates of 7.43 percent for Nevada Power and 6.95 percent for Sierra.

Source: NERA calculations as explained in text.

20. Q. PLEASE COMMENT ON DIFFERENCES IN EXTERNAL ENVIRONMENTAL WATER COSTS FOR THE OTHER 2024 IRP PLANS RELATIVE TO THE BALANCED PLAN, THE PREFERRED PLAN.

A. **Table Harrison Direct-6** provides the values for the differences in the water external environmental costs for the other 2024 IRP plans relative to the Balanced Plan, the Preferred Plan. Compared to the Balanced Plan (Preferred Plan), the external water costs are somewhat greater for the Renewable Plan, slightly smaller for the No Open Position Plan, and somewhat greater for the Low Carbon Plan.

Table Harrison Direct-6. Differences in Present Values of External Environmental Water Costs for Other 2024 IRP Plans Relative to the Balanced Plan (Preferred Plan), 2025-2050 (2025\$ Millions)

Balanced	Renewable	No Open Position	Low Carbon
-	\$3.82	-\$0.13	\$1.77

Notes: All values are present values as of 2025 in millions of 2025 dollars for the period 2025-2050 using inflation rate information provided by the Companies and nominal annual discount rates of 7.43 percent for Nevada Power and 6.95 percent for Sierra.

Source: NERA calculations as explained in text.

VII. ASSESSMENT OF OTHER ENVIRONMENTAL COSTS

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

A. Yes. I also considered potential environmental costs related to land use, solid waste disposal and water quality in Nevada. I concluded that any cost differences among the 2024 IRP plans related to these other environmental categories were likely to be highly site-specific and not likely to be significant relative to the estimated environmental costs.

VIII. ASSESSMENT OF TOTAL ENVIRONMENTAL COSTS

22. Q. PLEASE SUMMARIZE YOUR ASSESSMENT OF THE TOTAL MONETIZED ENVIRONMENTAL COSTS OF THE ALTERNATIVE 2024 IRP PLANS.

A. **Table Harrison Direct-7** summarizes my estimates of the total monetized environmental costs for the 2024 IRP resource plans, expressed as present values.

Table Harrison Direct-7. Present Values of Total Monetized Environmental Costs, 2025-2050 (2025\$ Millions)

	Balanced	Renewable	No Open Position	Low Carbon
Conventional Air Emission Costs	\$98	\$95	\$102	\$63
External Water Costs	\$13	\$17	\$13	\$15
Social Costs of Carbon	\$9,997	\$9,933	\$10,047	\$6,825
Total Environmental Cost	\$10,108	\$10,045	\$10,161	\$6,902

Notes: All values are present values as of 2025 in millions of 2025 dollars for the period 2025-2050. Conventional air emissions costs and external water costs use inflation information provided by the Companies and nominal annual discount rates of 7.43 percent for Nevada Power and 6.95 percent for Sierra. Social cost of carbon values use the 3 percent discount rate based on the Interagency Working Group. Total may differ from the sum of the rows due to independent rounding.

Source: NERA calculations as explained in text.

23. Q. PLEASE COMMENT ON THE DIFFERENCES IN TOTAL MONETIZED ENVIRONMENTAL COSTS FOR THE OTHER 2024 IRP PLANS RELATIVE TO THE BALANCED PLAN, THE PREFERRED PLAN.

A. Table Harrison Direct-8 provides estimates of the differences in total environmental costs for the other 2024 IRP plans relative to the Balanced Plan (the Preferred Plan). Compared to the Balanced Plan (Preferred Plan), the total environmental costs are slightly lower for the Renewable Plan (less than 1 percent), slightly greater for the No Open Position Plan (less than 1 percent) and substantially lower for the Low Carbon Plan (about 32 percent). Differences in the social cost of carbon account for the bulk of the differences in total environmental cost among the 2024 IRP resource plans.

Table Harrison Direct-8. Differences in Present Values of Total Monetized Environmental Costs Relative to the Balanced Plan (Preferred Plan), 2025-2050 (2025\$ Millions)

	Balanced	Renewable	No Open Position	Low Carbon
Conventional Air Emission Costs	-	-\$3	\$4	-\$35
External Water Costs	-	\$4	\$0	\$2
Social Costs of Carbon	-	-\$64	\$50	-\$3,172
Total Environmental Cost	-	-\$63	\$54	-\$3,205

Notes: All values are present values as of 2025 in millions of 2025 dollars for the period 2025-2050 using inflation information provided by the Companies and using nominal annual discount rates of 7.43 percent for Nevada Power and 6.95 percent for Sierra. Social cost of carbon values use the 3 percent discount rate based on the Interagency Working Group.

Source: NERA calculations as explained in text.

24. Q. PLEASE SUMMARIZE YOUR CONCLUSIONS ON THE NON-MONETIZED COSTS OF THE FIVE 2024 IRP PLANS.

A. I conclude that any differences in environmental costs related to land use, solid waste and water quality between the 2024 IRP plans are not likely to be significant relative to the estimated environmental costs.

IX. ECONOMIC IMPACTS

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

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

26. Q. WHAT MODEL DID YOU USE TO ESTIMATE ECONOMIC IMPACTS FOR THIS 2024 IRP ANALYSIS?

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

27. Q. PLEASE SUMMARIZE THE SOURCES OF INFORMATION YOU USED TO ASSESS THE ECONOMIC IMPACTS OF THE 2024 IRP PLANS.

A. I relied on several sources of information as discussed in the NERA Report, including information provided by the Companies, as well as data from the U.S. Department of Energy. As described in the NERA Report, the Companies provided information on construction costs, fuel costs, and annual operating and maintenance costs for the four 2024 IRP plans and for the Base Case (a plan assumed to be consistent with the REMI baseline) as well as information on the electricity revenue that would be collected from residential, commercial, and industrial customers under the four 2024 IRP plans and the Base Case. I used detailed cost data from EIA for renewable projects to assess the economic impacts in Nevada of the Companies' renewable PPAs. I also used information from the U.S. government on the expenditure profiles of various types of electricity generation units to develop specific inputs for the REMI modeling. Note that my analysis is based primarily upon the costs and revenue requirements related to the Companies' bundled customers and does not include effects related to its customers who only purchase transmission services ("transmission-only" customers), as the PWRR cost information is based on bundled customers. The only exception is that the costs and revenue requirements include those related to provision of 90 megawatts ("MW") of additional reserve capacity for transmission-only customers, which are also included in the PWRR.

I used the above information to develop inputs for the REMI modeling. The REMI inputs include estimates of the direct expenditures in Nevada in the 2024 IRP plans—including construction, fuel, and annual operating and maintenance expenditures in Nevada—as well as estimates of Nevada electricity revenue requirements for various customer classes under the plans. As noted below, these inputs are calculated relative to the Base Case for input to the REMI model.

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

A. REMI model includes a reference or “baseline” forecast. The Base Case developed by NV Energy is assumed to be consistent with the REMI baseline forecast. Because the Base Case is presumed to be included in the REMI baseline, the inputs to the REMI model are not the absolute values for expenditures and revenue requirements under the 2024 IRP plans but rather the *differences* between expenditures and revenue requirements for each of the 2024 IRP plans relative to those in the Base Case.

I first develop the REMI model results, which provide estimates of the growth of the Nevada economy under the various plans. I then develop tables that compare the *differences* in REMI model results among the plans. As with the environmental costs, I calculate the differences between the other 2024 IRP plans relative to the Balanced Plan, the Preferred Plan. Note that using the Balanced Plan to compare REMI model *results* for the other 2024 IRP plans is consistent with using the Base Case as the reference scenario for the purpose of developing the REMI model *inputs*.

I characterize the Nevada “economic impacts” in four impact categories: (1) gross state product, (2) personal income, (3) state and local tax revenue, and (4) employment. As discussed in the NERA Report, state and local tax revenue is calculated by NERA based on information developed by the Federation of Tax Administrators. Results for the other three impact categories come directly from the REMI model.

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

A. **Table Harrison Direct-9** shows the average annual expenditures in Nevada under the 2024 IRP plans and the Base Case. The table includes summaries for construction expenditures, fuel expenditures, and non-fuel operating and maintenance (“O&M”) expenditures. Only expenditures that occur in Nevada are included in these values because of the focus on estimating the economic impacts in Nevada. As discussed in the NERA Report, these values exclude certain categories of expenditures, such as market purchases, because those expenditures are assumed to flow to power producers outside Nevada (and thus not generate significant positive economic impacts in Nevada).

Table Harrison Direct-9. Average Annual Expenditures in Nevada, 2025-2050 (2025\$ Millions)

	Base	Balanced	Renewable	No Open Position	Low Carbon
Construction	\$3,235	\$3,346	\$3,616	\$2,973	\$3,283
Fuel	\$495	\$489	\$478	\$504	\$357
O&M	\$730	\$720	\$820	\$619	\$921
Total	\$4,460	\$4,555	\$4,913	\$4,096	\$4,561

Notes: All values are average annual values over the period from 2025 to 2050 in millions of 2025 dollars. Dollar year conversions are based on inflation rate information provided by the Companies. Total may differ from the sum of the rows due to independent rounding.

Source: NERA calculations as explained in text.

Table Harrison Direct-10 shows the differences in average annual expenditures in Nevada over the period from 2025 to 2050 for the 2024 IRP plans relative to the Base Case (which as noted is assumed to be consistent with REMI’s reference case). The differences relative to the Base Case in each year are the values—based upon detailed expenditure categories—that are input into the REMI model. Note

that the average annual values in the summary tables do not reflect the differences in timing of expenditures over the 26-year period, although these differences in timing are included in the REMI modeling.

Table Harrison Direct-10. Average Annual Expenditures in Nevada, Relative to the Base Case, 2025-2050 (2025\$ Millions)

	Base	Balanced	Renewable	No Open Position	Low Carbon
Construction	-	\$111	\$381	-\$262	\$49
Fuel	-	-\$6	-\$17	\$9	-\$138
O&M	-	-\$10	\$90	-\$111	\$191
Total	-	\$95	\$454	-\$363	\$101

Notes: All values are average annual values over the period from 2025 to 2050 in millions of 2025 dollars. Dollar year conversions are based on inflation rate information provided by the Companies. Total may differ from the sum of the rows due to independent rounding.

Source: NERA calculations as explained in text.

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

A. **Table Harrison Direct-11** shows the average annual electricity revenue requirements for 2025-2050, apportioned by customer class (based on the methodology described in the NERA Report that combines information for Nevada Power and Sierra).

Table Harrison Direct-11. Average Annual Electricity Revenue by Customer Class, 2025-2050 (2025\$ Millions)

	Base	Balanced	Renewable	No Open Position	Low Carbon
Residential	\$1,678	\$1,715	\$1,775	\$2,006	\$1,897
Commercial	\$854	\$878	\$911	\$1,010	\$994
Industrial	\$356	\$368	\$383	\$416	\$421
Total	\$2,888	\$2,961	\$3,068	\$3,432	\$3,311

Notes: All values are average annual values over the period from 2025 to 2050 in millions of 2025 dollars. Dollar year conversions are based on inflation rate information provided by the Companies. Total may differ from the sum of the rows due to independent rounding.

Source: NERA calculations as explained in text.

Table Harrison Direct-12 shows the differences in average annual electricity revenue requirements for the 2024 IRP plans relative to the Base Case. The differences relative to the Base Case in each year are the values that are included in the REMI modeling, based on detailed information that reflects the direct impacts on the three sets of customers. As with the expenditures, these average values do not reflect differences in timing, although timing differences are included in the REMI modeling.

Table Harrison Direct-12. Average Annual Electricity Revenue by Customer Class, Relative to the Base Case, 2025-2050 (2025\$ Millions)

	Base	Balanced	Renewable	No Open Position	Low Carbon
Residential	-	\$37	\$97	\$328	\$214
Commercial	-	\$24	\$57	\$156	\$144
Industrial	-	\$12	\$27	\$60	\$71
Total	-	\$73	\$180	\$544	\$429

Notes: All values are average annual values over the period from 2025 to 2050 in millions of 2025 dollars. Dollar year conversions are based on inflation rate information provided by the Companies. Total may differ from the sum of the rows due to independent rounding.

Source: NERA calculations as explained in text.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

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

A. **Table Harrison Direct-13** provides estimates of the differences in economic outcome measures for selected years in Nevada for the 2024 IRP plans relative to the Base Case. The relative economic impacts of the 2024 IRP plans vary over the selected years in the 26-year period from 2025-2050, reflecting the different timing of construction and other major initial changes in economic activity.

///
///
///

Table Harrison Direct-13. Growth in Nevada Economy for Selected Years Relative to the Base Case, 2025-2050

	Nevada Economic Impact						
	2025	2026	2027	2028	2035	2045	2050
Base							
Gross State Product (millions of 2025 dollars)	-	-	-	-	-	-	-
Personal Income (millions of 2025 dollars)	-	-	-	-	-	-	-
State & Local Tax Revenue (millions of 2025 dollars)	-	-	-	-	-	-	-
Employment (total jobs)	-	-	-	-	-	-	-
Balanced							
Gross State Product (millions of 2025 dollars)	6	-61	255	-144	-35	-48	-41
Personal Income (millions of 2025 dollars)	4	-35	166	-85	-32	-36	8
State & Local Tax Revenue (millions of 2025 dollars)	0	-3	16	-8	-3	-3	1
Employment (total jobs)	49	-499	2,101	-1,071	-298	-280	-107
Renewable							
Gross State Product (millions of 2025 dollars)	-29	-75	154	-233	-17	1,467	-3
Personal Income (millions of 2025 dollars)	-18	-46	102	-140	8	1,041	161
State & Local Tax Revenue (millions of 2025 dollars)	-2	-4	10	-13	1	98	15
Employment (total jobs)	-243	-642	1,250	-1,716	-125	9,153	498
No Open Position							
Gross State Product (millions of 2025 dollars)	21	-41	287	260	-2,051	-1,218	-2,366
Personal Income (millions of 2025 dollars)	13	-23	186	179	-1,153	-873	-1,649
State & Local Tax Revenue (millions of 2025 dollars)	1	-2	18	17	-108	-82	-155
Employment (total jobs)	173	-326	2,383	2,156	-14,337	-7,760	-13,762
Low Carbon							
Gross State Product (millions of 2025 dollars)	-35	-14	-27	1,060	-1,885	-386	-38
Personal Income (millions of 2025 dollars)	-21	-10	-17	660	-950	-188	-46
State & Local Tax Revenue (millions of 2025 dollars)	-2	-1	-2	62	-89	-18	-4
Employment (total jobs)	-292	-143	-238	8,018	-12,600	-1,391	639

Notes: The Base Case is assumed to be consistent with the REMI Baseline scenario. Expenditure and electricity revenue inputs are modeled for the five 2024 IRP plans in comparison to the Base Case and economic impacts are measured relative to the Base Case. Employment values include full time and part time jobs.

Source: NERA calculations as explained in text.

Table Harrison Direct-14 provides estimates of the average annual economic impacts in Nevada over the 26-year period from 2025-2050 for the other 2024 IRP plans relative to the Balanced Plan, the Preferred Plan. These average annual results do not reflect the substantial differences over the analysis period in the relative economic impacts of the 2024 IRP plans. Relative to the Balanced Plan, the economic impacts are positive for the Renewable Plan and negative for the No

Open Position Plan for all four economic impact metrics. The Low Carbon Plan has greater economic impacts than the Balanced Plan for three of the metrics and smaller economic impacts for one of the metrics.

Table Harrison Direct-14. Average Annual Differences in Nevada Economic Impacts Relative to the Balanced Plan (Preferred Plan), 2025-2050

	Balanced	Renewable	No Open Position	Low Carbon
Gross State Product (millions of 2025 dollars)	-	185	-257	-28
Personal Income (millions of 2025 dollars)	-	164	-191	71
State & Local Tax Revenue (millions of 2025 dollars)	-	15	-18	7
Employment (total jobs)	-	1,350	-1,458	639

Notes: Employment values include full time and part time jobs.
Source: NERA calculations as explained in text.

X. CONCLUSIONS

32. Q. PLEASE PROVIDE ESTIMATES OF THE PWSC FOR THE 2024 IRP PLANS BASED UPON YOUR ESTIMATES OF ENVIRONMENTAL COSTS.

A. **Table Harrison Direct-15** provides estimates of the PWSC for the 2024 IRP plans, and **Table Harrison Direct-16** provides estimates of the PWSC for the other 2024 IRP plans relative to the Balanced Plan, the Preferred Plan. As I indicated in discussing the objectives of my testimony, PWSC is defined as the sum of the PWRR and the environmental costs. Compared to the Balanced Plan (Preferred Plan), the Renewable and Low Carbon Plans have a slightly greater PWSC (about 2 percent and 5 percent, respectively), and the No Open Position Plan has a somewhat greater PWSC (about 10 percent).

Table Harrison Direct-15. Present Worth of Societal Costs, 2025-2050 (2025\$ Millions)

	Balanced	Renewable	No Open Position	Low Carbon
PWRR	\$41,294	\$42,342	\$46,293	\$47,115
Conventional Air Emission Costs	\$98	\$95	\$102	\$63
External Water Costs	\$13	\$17	\$13	\$15
Social Costs of Carbon	\$9,997	\$9,933	\$10,047	\$6,825
PWSC	\$51,402	\$52,386	\$56,454	\$54,017

Notes: All values are present values as of 2025 in millions of 2025 dollars for the period 2025-2050. Values other than the social costs of carbon are based on inflation information provided by the Companies and nominal annual discount rates of 7.43 percent for Nevada Power and 6.95 percent for Sierra. Social cost of carbon values use the 3 percent discount rate based on the Interagency Working Group. Total may differ from the sum of the rows due to independent rounding.

Source: NERA calculations as explained in text.

Table Harrison Direct-16. Differences in Present Worth of Societal Costs Relative to the Balanced Plan (Preferred Plan), 2025-2050 (2025\$ Millions)

	Balanced	Renewable	No Open Position	Low Carbon
PWRR	-	\$1,047	\$4,998	\$5,821
Conventional Air Emission Costs	-	-\$3	\$4	-\$35
External Water Costs	-	\$4	\$0	\$2
Social Costs of Carbon	-	-\$64	\$50	-\$3,172
PWSC	-	\$985	\$5,052	\$2,615

Notes: All values are present values as of 2025 in millions of 2025 dollars for the period 2025-2050. Values other than the social costs of carbon are based on inflation information provided by the Companies and nominal annual discount rates of 7.43 percent for Nevada Power and 6.95 percent for Sierra. Social cost of carbon values use the 3 percent discount rate based on the Interagency Working Group. Total may differ from the sum of the rows due to independent rounding.

Source: NERA calculations as explained in text.

33. Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE NET ECONOMIC BENEFITS OF THE 2024 IRP PLANS BASED UPON YOUR ESTIMATES OF ECONOMIC IMPACTS.

A. Relative to the Balanced Plan, the economic impacts are positive for the Renewable Plan and negative for the No Open Position Plan for all four economic impact

metrics. The Low Carbon Plan has greater economic impacts than the Balanced Plan for three of the metrics and smaller economic impacts for one of the metrics.

34. Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

EXHIBIT HARRISON-DIRECT-1

NERA

Economic Consulting

David Harrison, Ph.D.
Affiliated ConsultantNational Economic Research Associates, Inc.
99 High Street, 32nd Floor
Boston, Massachusetts 02110
+1 617 927 4500 Fax +1 617 927 4501
www.nera.com**David Harrison**
Affiliated Consultant

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

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

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

the potential economic impacts of federal regulations on carbon dioxide emissions from existing power plants. He has lectured frequently on climate change and related topics at numerous conferences in the United States and abroad.

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

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

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

Before joining NERA, Dr. Harrison was an Associate Professor at the John F. Kennedy School of Government at Harvard University, where he taught economics, energy and environmental policy, cost-benefit analysis, transportation policy, regional economic development, and other

courses. He also served as a Senior Economist at the U.S. government's President's Council of Economic Advisors, where he had responsibility for environment and energy policy issues, among others. He is the author or co-author of two books on environmental policy and numerous articles on various topics in professional journals.

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

Education

Harvard University

Ph.D., Economics, 1974

M.A., Economics, 1972

London School of Economics and Political Science

M.Sc., Economics, 1968

Harvard University

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

Professional Experience

National Economic Research Associates, Inc.

1988- *Affiliated Consultant, Managing Director, Senior Vice President, Vice President.* Directs projects in the economics of the environment, energy, transportation, regional economic development, and other areas.

Putnam, Hayes & Bartlett, Inc.

1987-1988 *Senior Associate.* Directed projects in the economics of energy, antitrust, and other areas.

Dun & Bradstreet Technical Economic Services

1985-1987 *Director of Product Development.* Directed economic studies in energy, transportation, and industrial location.

John F. Kennedy School of Government, Harvard University

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

President's Council of Economic Advisors

- 1979-1980 *Senior Staff Economist.* Worked with other White House staff and agency officials on domestic issues. Areas of responsibility included energy, environment, and transportation. Principal staff on the Regulatory Analysis Review Group. Principal White House staff for the review of Administration policy regarding the automotive industry.
- Department of City and Regional Planning, Harvard University**
- 1974-1979 *Assistant and Associate Professor.* Areas of instruction: microeconomics; statistics; econometrics; transportation; environment; urban development; and housing policy. Participant, MIT-Harvard Joint Center for Urban Studies. Faculty Chairman, Concentration in Land Use and Environment.
- National Bureau of Economic Research**
- 1974 *Research Associate.* Co-author of benefit-cost study of automotive air pollution prepared by the National Academy of Sciences for the Committee on Public Works, U.S. Senate.
- U.S. Department of Transportation**
- 1973-1974 *Economist.* Performed economic studies of transportation issues, including urban mass transportation, automobile emission and safety programs, and highway finance.
- Department of Economics, Harvard University**
- 1970-1974 *Teaching Fellow and Assistant Head Tutor.* Areas of instruction: microeconomics; macroeconomics; econometrics; transportation; public finance; environmental policy; and housing policy.
- The Urban Institute**
- 1971 *Research Economist.* Participated in econometric studies as participant in the Program on Local Public Finance.
- U.S. Department of Housing and Urban Development**
- 1969 *Economist.* Participated in economic evaluations of HUD infrastructure programs, primarily the water and sewer grant program.

Honors and Professional Activities

Summa cum Laude, Senior Honors Thesis, Harvard University.

Phi Beta Kappa, Harvard University.

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

Graduate Prize Fellowship, Harvard University.

Member, American Economic Association.

Member, Association of Environmental and Resource Economists.

Member, International Association of Energy Economists.

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

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

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

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

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

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

Member, Harvard Graduate Society Council.

Member, RECLAIM Advisory Committee (Los Angeles).

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

Participant, Aspen Institute Dialogue on Climate Change.

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

Consultant to the following public and private organizations:

U.S. Environmental Protection Agency; U.S. Department of Transportation; Massachusetts Port Authority; Organization for Economic Cooperation and Development (OECD, Paris); European Commission Directorate-General Environment; Civil Aeronautics Board; Italian Ministry of Environment; Massachusetts Department of Environmental Protection; UK Department of Transport; UK Department for Environment, Food and Rural Affairs, UK Department of Trade and Industry, City of Chicago Department of Aviation; Conference Board of Canada; South Coast Air

Quality Management District; Massachusetts Department of Environmental Management; and numerous state and local governments, trade associations, and private firms.

Reviewer for the following professional journals:

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

I. Publications

A. Books

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

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

B. Articles and Published Reports

Tiered Approach to Sustainability Analysis in Sediment Remediation Decision Making (with Amanda McNally, Anne Fitzpatrick, Andrew Busey and Sabine Apitz). *Remediation*, 20:1-16, September 2020.

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

Economics in Environmental Decision-Making: US Environmental Protection Agency Provides for Site-Specific Cost-Benefit Analysis in Setting 316(b) Clean Water Standards (with Noah Kaufman), NERA Economic Consulting, May 2014.

“Economic Policy Instruments for Reducing Greenhouse Gas Emissions” (with Andrew Foss, Per Kleinas, and Daniel Radov), chapter in *Oxford Handbook of Climate Change*, edited by David Schlosberg, John Dryzek, and Richard Norgaard, August 2011.

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

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

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

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

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

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

Complexities of Allocation Choices in a Greenhouse Gas Emissions Trading Program (with Per Klevnas and Dan Radov), International Emissions Trading Association (IETA), September 2007.

“State Restrictions on Mercury Trading Could Prove Expensive, Ineffective” (with James Johndrow) in *Natural Gas Electricity, Volume 24, Number 2*. Isabelle Cohen, Hoboken, NJ: Wiley Periodicals, Inc., September 2007.

“Experience for Member States in Allocating Allowances: United Kingdom” (with Dan Radov) in *Allocation in the European Emissions Trading Scheme*. A. Denny Ellerman, Barbara K. Buchner and Carlo Carraro, Cambridge, UK: Cambridge University Press, 2007.

Interactions of Cost-Containment Measures and Linking of Greenhouse Gas Emissions Cap-and-Trade Programs, Electric Power Research Institute, November 2006.

Interactions of Greenhouse Gas Emission Allowance Trading with Green and White Certificate Schemes, European Commission Directorate-General Environment, November 2005.

Carbon Markets, Electricity Prices and “Windfall Profits”—Emerging Information from the European Union Emissions Trading Scheme, Electric Power Research Institute, September 2005.

Economic Instruments for Reducing Ship Emissions in the European Union, European Commission, Directorate-General Environment, June 2005.

Evaluation of the Feasibility of Alternative Market-Based Mechanisms to Promote Low-Emission Shipping in European Union Sea Areas, European Commission, Directorate-General Environment, March 2004.

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

Alternatives for Implementing the UK’s National Allocation Plan, Department for Environment, Food and Rural Affairs, with AEA Technology and SPRU, August 2003.

Report on UK's Implementation of the CO₂ National Allocation Plan Under the European Union Greenhouse Gas Emissions Trading Programme, Department for Environment, Food and Rural Affairs, with AEA Technology and SPRU, July 2003.

“Ex Post Evaluation of the RECLAIM Emissions Trading Program for the Los Angeles Air Basin,” National Policies Division, OECD Environment Directorate, June 2003.

Emission Trading in the U.S.: Experience, Lessons, and Considerations for Greenhouse Gases. (with Denny Ellerman and Paul Joskow). Pew Center on Global Climate Change, May 2003.

“Carbon Emission Trading: Creating a New Traded Commodity Market in Europe,” in *WorldPower*, October 2002.

“A Groundbreaking Proposal: European Greenhouse Gas Emissions Trading,” in *Infrastructure Journal*, August 2002.

“Europe Warms to Emissions Trading,” in *Energy Regulation Brief*, NERA Economic Consulting, April 2002.

Evaluation of Alternative Initial Allocation Methods in a European Union Greenhouse Gas Emissions Cap-and-Trade Programme, European Commission Directorate-General Environment, March 2002.

“Economics Issues in Section 316(B) Decisions,” in *A Towering Challenge*, C. Richard Bozek, Electric Perspectives, January/February 2002.

“Tradable Permit Programs for Air Quality and Climate Change,” in *International Yearbook of Environmental and Resource Economics, Volume VI*, Henk Folmer and Thomas Tietenberg (Eds.). London: Edward Elgar, 2002.

Energy-Environment Policy Integration and Coordination Study (contributor), Palo Alto, CA: Electric Power Research Institute, December 2000.

Critical Issues in International Greenhouse Gas Emissions Trading: Setting Baselines for Credit-Based Trading Programs-Lessons Learned from Relevant Experience. Palo Alto, CA, Electric Power Research Institute, June 2000.

“Tradable Permits for Air Pollution Control: The United States Experience,” in *Domestic Tradable Permit Systems for Environmental Management: Issues and Challenges*, J.P. Barde and T. Jones (Eds.). Paris: Organization for Economic Cooperation and Development, 1999.

“Emissions Trading: Turning Theory Into Practice in the Los Angeles Air Basin,” in *Pollution for Sale: Emissions Trading and Joint Implementation*, S. Sorrell, and J. Skea (Eds.). London: Edward Elgar, 1999.

“Commentary: International Greenhouse Gas Trading and the Kyoto Protocol,” in *Climate Change Policy: Practical Strategies to Promote Economic Growth and Environmental Quality*, C. Walker, M. Bloomfield, and M. Thorning (Eds.). Washington, DC: The American Council for Capital Formation Center for Policy Research, May 1999

“Priorities for the Development of GHG Trading Programs: Implications of the U.S. Experience,” in *Global Climate Change: Science, Policy, and Mitigation/Adaptation Strategies*, C.V. Mathai and J. Kinsman (Eds.). Washington, DC: Air & Waste Management Association, October 1998.

“Commentary on ‘Tradable Emissions Rights and Joint Implementation for Greenhouse Gas Abatement: A Look Under the Hood,’” in *The Impact of Climate Change Policy on Consumers: Can Tradable Permits Reduce the Cost?* C. Walker, M. Bloomfield, and M. Thorning (Eds.). Washington, DC: The American Council for Capital Formation Center for Policy Research, April 1998.

“Considerations in Designing and Implementing an Effective International Greenhouse Gas Trading Program,” Global Climate Coalition, October 1997.

“Environmental Adders in the Real World,” (with A. Nichols), in *Resources and Energy Economics*, December 1996.

“Recent Evidence on the Appropriate Timing of Reductions in Greenhouse Gas Emissions,” (with A. Nichols), Global Climate Coalition, July 1996.

“The Use of Externality Adders for Greenhouse Gas Emissions in Electric Utility Resource Planning,” in *Internalization of Social Costs of Energy Conversion and Transportation in the United States and Europe for a Sustainable Development*, O. Hohmeyer and R. Ottinger (Eds.). Berlin: Springer-Verlag, 1996.

The Distributive Effects of Economic Instruments for Global Warming. Paris: Organization for Economic Cooperation and Development, 1996.

“The Socioeconomic Effects of Externality Adders for Electric Utility Emissions,” in *Technical Review of Externalities Issues*. Electric Power Research Institute, December 1994.

The Distributive Effects of Economic Instruments for Environmental Policy. Paris: Organization for Economic Cooperation and Development, 1994.

“Utility Externalities and Emissions Trading: California is Developing a Better Way,” in *Social Costs of Energy - Present Status and Future Trends*, R. Ottinger and O. Hohmeyer (Eds.). Berlin: Springer-Verlag 1994.

“Who Wins and Who Loses from Economic Instruments?” *The OECD Observer* 180:29-31, February/March 1993.

“Tradable Permits and Social Costing: The California Experience,” prepared for the American Economic Association and Allied Social Science Association Meeting, Anaheim, California, January 6, 1993.

“Emissions Trading: A Better Way to Include Environmental Costs in Electric Utility Resource Planning,” American Planning Association and Edison Electric Institute, March 1992.

“Economists’ Contribution to the Environment,” *Journal of Air and Waste Management Association*, October 1991.

“Environmental Policy in Europe: Economic Lessons from the United States Experience,” in *Environmental Damages*. Rome, V. Polidoro (Ed.). Italy: Italian Government Printing Office, August 1990.

“Potential Cost Savings and Environmental Effects of Using Emissions Trading to Manage NO_x in Ontario,” (with A. Nichols), in *Air and Waste Management Through the 90’s*, R. E. Clement (Ed.), Air and Waste Management Association, Ontario, Canada, April 1990.

“Market-Based Approaches for Environmental Protection: Implications for Business,” (with A. Nichols), in *Special Report on Global Environmental Issues*, B. Gentry (Ed.). Washington, DC: The Bureau of National Affairs, 1990.

Comments before the Department of Interior on Advanced Notice of Proposed Rulemaking Regarding Revision of Natural Resource Damage Assessment Regulations, 43 CFR Part 11, (with J. Hausman), November 1989.

“To Live and Breathe in L.A.,” (with P. Portney, A. Krupnick, and H. Dowlatabadi), *Issues in Science and Technology* V(4):Summer 1989.

“Policy Approaches for Controlling Greenhouse Gases,” Energy Research Group, May 1989.

“Yes to Clean Air, But at What Cost?” *The New York Times*, March 26, 1989.

“Realistic Air-Quality Goals Will Prevent Cost Explosion,” *Los Angeles Times*, January 11, 1989.

“Put the Clock on Landing Fees,” *The Journal of Commerce*, November 10, 1988.

“Reforming Airport Pricing to Reduce Congestion,” Conference on Transportation Options for the 21st Century, Boston, Massachusetts, July 1988.

“Awaiting the Second Shoe at Congested Logan,” *The Boston Globe*, March 29, 1988.

Research and Demonstration of Improved Methods for Carrying Out Benefit-Cost Analysis of Individual Regulations, Volumes I - IV, (Principal Investigator), prepared for the U.S. Environmental Protection Agency, Final Report, November 1984.

“Using the Hedonic Housing Value Method to Estimate the Benefits of Hazardous Waste Cleanup,” (with J. Stock), U.S. Environmental Protection Agency, November 1984.

“Using the Averting Cost Method to Estimate the Benefits of Hazardous Waste Cleanup,” (with M. O’Keeffe), U.S. Environmental Agency, November 1984.

“The Value of Acquiring Information Under Section 8(a) of the Toxic Substances Control Act: A Decision-Analytic Approach,” (with A. Nichols, L. Boden, and R. Terrell), U.S. Environmental Protection Agency, November 1984.

“Hedonic Housing Values, Local Public Goods, and the Benefits of Hazardous Waste Cleanup,” (with J. Stock), Discussion Paper, Energy and Environmental Policy Center, Harvard University, November 1984.

“Banning Hazardous Material from Land Disposal Facilities,” *Hazardous Waste* 1(1984).

“Benefit-Cost Analysis of Environmental Regulation: Case Studies of Hazardous Air Pollutants,” (with J. Haigh and A. Nichols), *Harvard Environmental Law Review* 8(1984).

“Benefit-Based Flexibility in Environmental Regulation,” (with A. Nichols), Discussion Paper, Energy and Environmental Policy Center, Harvard University, April 1983.

“The Regulation of Aircraft Noise,” in *Incentive Arrangements for Environmental Protection*, T. Schelling (Ed.). Cambridge, MA: MIT Press, 1983.

“Imports and the Future of the U.S. Automobile Industry,” (with J. Gomez-Ibanez), *American Economic Review*, Papers and Proceedings 72 (May 1982).

“Who Loses from Reform of Environmental Regulation,” (with P. Portney), in *Reform of Environmental Regulation*, Wesley Magat (Ed.). Cambridge, MA: Ballinger Publishing Company, 1982.

“Regulatory Reform in the Large and in the Small,” (with P. Portney), in *Reforming Government Regulation*, LeRoy Graymer (Ed.). Beverly Hills, CA: Sage Publications, 1982.

“Making Ready for the Clean Air Act,” (with P. Portney), *Regulation* 5(March/April 1981).

“Regulation and Distribution: An Agenda for Research,” in *Creating an Agenda for Regulatory Research*, A. Ferguson (Ed.). Cambridge, MA: Ballinger Publishing Company, 1981.

“Cost-Benefit Analysis and the Regulation of Environmental Carcinogens,” in *Management of Carcinogenic Risk*, W. Nicholson (Ed.). New York: New York Academy of Sciences, 1981.

“Distributional Objectives in Health and Safety Regulation,” in *The Benefits of Health and Safety Regulation*, A. Ferguson (Ed.). Lexington, MA: D.C. Heath and Company, 1981.

“The Local Government Role in Energy Policy,” (with M. Shapiro), in *Energy and Environment: Conflict and Resolution*, R. Axelrod (Ed.). Lexington, MA: D.C. Heath and Company, 1981.

“Simulating the Impacts of Transportation Policy on Urban Land Use,” Discussion Paper, Department of City and Regional Planning, Harvard University, April 1979. (Presented at meeting of the Eastern Economics Association, May 1979.)

“Income and Urban Development,” Discussion Paper, Department of City and Regional Planning, Harvard University, April 1979.

“Discussion of Robert C. Ellickson, ‘Public Property Rights: Vicarious Intergovernmental Rights and Liabilities as a Technique for Correcting Intergovernmental Spillovers,’” in *Essays on the Law and Economics of Local Government*, D. Rubinfeld (Ed.). Washington, D.C: The Urban Institute, 1979.

“The Distribution of Benefits from Improvements in Urban Air Quality,” (with D. Rubinfeld), *Journal of Environmental Economics and Management* 5(December 1978).

“The Impact of Transit Systems on Land Use Patterns in the Pre-Automobile Era,” Discussion Paper, Department of City and Regional Planning, Harvard University, December 1978.

“The Air Pollution and Property Value Debate: Some Empirical Evidence,” (with D. Rubinfeld), *Review of Economics and Statistics* 60(November 1978).

“Transportation Technology and the Dynamics of Urban Land Use Patterns,” paper presented to the Conference on Urban Transportation, Planning, and the Dynamics of Land Use, Northwestern University, June 1978.

“Hedonic Housing Values and the Demand for Clean Air,” (with D. Rubinfeld), *Journal of Environmental Economics and Management* 5(March 1978).

“Controlling Automotive Emissions: How to Save More Than \$1 Billion per Year and Help the Poor Too,” *Public Policy* 2 (Fall 1977).

“Reply to Michelle White’s Comment on ‘Cumulative Urban Growth and Urban Density Functions,’” (with J. Kain), *Journal of Urban Economics* 4(January 1977).

“Cumulative Urban Growth and Urban Density Functions,” (with J. Kain), *Journal of Urban Economics* 1(January 1974).

II. Consulting Reports for Directed Projects

A. Climate Change

Environmental Costs and Economic Impacts of Four Resource Cases for the Fifth Amendment to the 2021 Integrated Resource Plan, prepared for NV Energy, July 2023.

Environmental Costs and Economic Impacts of Three Resource Cases for the Fourth Amendment to the 2021 Integrated Resource Plan, prepared for NV Energy, November 2022.

Environmental Costs and Economic Impacts of Two Resource Cases for the First Amendment to the 2021 Integrated Resource Plan, prepared for NV Energy, March 2022.

Environmental Costs and Economic Impacts of the 2021 Integrated Resource Plan, prepared for NV Energy, May 2021.

Environmental Costs and Economic Impacts of Additional Resource Cases for the Fourth Amendment to the 2018 Integrated Resource Plan: Supplemental Report, prepared for NV Energy, October 2020.

Impacts of Climate Change on Road Salt Demand, Confidential Client, September 2020.

Environmental Costs and Economic Impacts of Additional Resource Cases for the Fourth Amendment to the 2018 Integrated Resource Plan, prepared for NV Energy, July 2020.

Environmental Costs and Economic Impacts of Additional Resource Cases for the Third Amendment to the 2018 Integrated Resource Plan, prepared for NV Energy, June 2019.

Evaluation of Alternative Passenger Car and Light Truck Corporate Average Fuel Economy (CAFE) Standards for Model Years 2021-2026, prepared for Alliance of Automobile Manufacturers, October 2018.

Environmental Costs and Economic Impacts of the 2018 Integrated Resource Plan, prepared for Nevada Power Company, June 2018.

Environmental Costs and Economic Impacts of 100 MW Generic Technology/Resource Options (Supplemental Report to 2016 IRP), prepared for Sierra Pacific Power Company, September 2016.

Environmental Costs and Economic Impacts of the 2016 Integrated Resource Plan, prepared for Sierra Pacific Power Company, June 2016.

Potential Electricity and Energy Price Outcomes under EPA's Federal Plan Alternatives for the Clean Power Plan, prepared for Group of Energy-Intensive Industry Associations, January 2016.

Energy and Consumer Impacts of EPA's Clean Power Plan, prepared for the American Coalition for Clean Coal Electricity, November 2015.

Environmental Costs and Economic Impacts of the 2015 Integrated Resource Plan, prepared for Nevada Power Company, June 2015.

Investing in a Time of Climate Change, prepared with Mercer for a group of asset-owner and manager partners, June 2015.

Impacts of the EPA Clean Power Plan Building Blocks on Texas Energy Markets, prepared for Luminant, November 2014.

Potential Energy Impacts of the EPA Proposed Clean Power Plan, prepared for the American Coalition for Clean Coal Electricity and other organizations, October 2014.

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

Linkage of a Potential South African GHG Cap and-Trade Program: Initial Scoping Study," prepared for Sasol, June 13, 2013.

Environmental and Economic Impacts of the 2013 Integrated Resource Plan, prepared for Sierra Pacific Power Company, June 2013.

Economic Outcomes of a U.S. Carbon Tax, prepared for National Association of Manufacturers, February 26, 2013.

Environmental and Economic Impacts of the Second Amendment to the 2010 Integrated Resource Plan, prepared for Sierra Pacific Power, August 2012.

Analysis of EPA's Proposed GHG, New Source Performance Standard for Electric Generating Units, prepared for American Coalition for Clean Coal Electricity, June 25, 2012

Environmental and Economic Impacts of the 2012 Integrated Resource Plan, prepared for Nevada Power Company, June 2012.

Evaluation of Incentives in International Sectoral Crediting Mechanisms, prepared for Enel S.p.A., October 2011.

Environmental and Economic Impacts of the First Amendment Supplemental Filing to the 2009 Integrated Resource Plan, prepared for Nevada Power Company, October 2011.

Environmental Costs and Economic Impacts of the Second Amendment to the 2009 Integrated Resource Plan, prepared for Nevada Power Company, August 2011.

Environmental Costs and Economic Impacts of the 2010 Integrated Resource Plan, prepared for Sierra Pacific Power Company, July 2010.

Environmental Costs and Economic Impacts of the 2009 Integrated Resource Plan, prepared for Nevada Power Company, February 2010.

Follow-up letter to US Environmental Protection Agency Clarifying Key Conclusions from Review of EPA's Approach to Aggregating Emissions Across Time in Proposed Revisions of Renewable Fuel Standards, prepared on behalf of Growth Energy, January 2010.

Review of EPA's Approach to Aggregating Emissions across Time in Proposed Revisions of Renewable Fuel Standards, prepared for Growth Energy for submission to U.S. EPA, Docket ID No. EPA-HQ-OAR-2005-0161, September 2009.

Differentiation among Batches of Conventional Biofuels based on Greenhouse Gas Emissions, prepared for Growth Energy, September 2009.

Impacts of Waxman-Markey Bill on US Refiners: Preliminary Estimates, prepared for major industrial sector, July 2009.

Effects of Waxman-Markey on Natural Gas and Electricity Businesses: Phase 1, prepared for a Midwest utility, July 2009.

Impacts of the California Greenhouse Gas Emission Standards on Motor Vehicle Sales, prepared for the Alliance of Automobile Manufacturers, April 2009.

Accounting for Differences in the Timing of Emissions in Calculating Carbon Intensity for the California Low Carbon Fuels Standard, prepared for the Renewable Fuels Association, April 2009.

Environmental Costs and Economic Benefits of Electric Utility Resource Selection, prepared for Nevada Power Company, March 2009.

Environmental Costs and Economic Benefits of Electric Utility Resource Selection, prepared for Nevada Power Company, March 2009.

Evaluation of Alternative Benchmarked Sector-Level Allocation Formulas, prepared for a major U.S. industrial trade group, October 2008.

Evaluation of NHTSA's Benefit-Cost Analysis of 2011-2015 CAFE Standards, prepared for the Alliance of Automobile Manufacturers, July 2008.

Impacts of Climate Change Policies Using the NERA Carbon Financial Impacts Model (Phase 2 Study), prepared for a major U.S. industrial manufacturer, June 2008.

Effects of the Regional Greenhouse Gas Initiative on Regional Electricity Markets, prepared for AES and Dynegy, June 2008.

Environmental Costs and Economic Benefits of Electric Utility Resource Selection, prepared for Nevada Power Company, May 2008.

Impacts of Potential Climate Change Policy using the NERA Carbon Financial Impacts Model, prepared for a major U.S. trade association, April 2008.

Market Conditions and the Pass-Through of Compliance Costs in a Carbon Emission Cap-and-Trade Program, prepared for Conoco Phillips, January 2008.

Evaluation of the Financial Impacts of Alternative Climate Change Cap-and-Trade Programs using the NERA Carbon Financial Impacts Model, prepared for a major U.S. industrial manufacturer, December 2007.

Evaluation of the Financial Impacts of Alternative Climate Change Cap-and-Trade Programs using the NERA Carbon Financial Impacts Model, prepared for a major U.S. energy company, November 2007.

Evaluation of the Financial Impacts of Alternative Climate Change Cap-and-Trade Programs using the NERA Carbon Financial Impacts Model, prepared for a major U.S. industrial manufacturer, October 2007.

Evaluation of the Financial Impacts of Alternative Climate Change Cap-and-Trade Programs using the NERA Carbon Financial Impacts Model, prepared for a major U.S. energy company, September 2007.

Environmental Costs and Economic Benefits of Electric Utility Resource Selection, prepared for Sierra Pacific Power Company, June 2007.

Evaluation of the Financial Impacts of Alternative Climate Change Cap-and-Trade Programs using the NERA Carbon Financial Impacts Model, prepared for a major U.S. energy company, March 2007.

Effectiveness of the California Light Duty Vehicle Regulations as Compared to Federal Regulations, in collaboration with Sierra Research, Inc. and Air Improvement Resource, Inc., prepared for the Alliance of Automobile Manufacturers, June 2007.

Financial Impacts of Potential Mandatory CO₂ Cap-and-Trade Programs using the NERA Carbon Financial Impacts Model, prepared for a major U.S. trade association, January 2007.

Modeling the Fleet Population Effects of the Rhode Island Proposal to Reduce Greenhouse Gas Emissions from Motor Vehicles, prepared for the Alliance of Automobile Manufacturers, November 2005.

Review of Potential Expansion of the UK Phase II National Allocation Plan to the Petrochemical Sector, prepared for UK Department for the Environment, Food and Rural Affairs (DEFRA) and Department of Trade and Industry (DTI), November 2005.

The Impacts of CO₂ Prices on European Electricity Prices, prepared for Electricité de France (EDF), October 2005.

Modeling the Fleet Population Effects of the Massachusetts Proposal to Reduce Greenhouse Gas Emissions from Motor Vehicles, prepared for the Alliance of Automobile Manufacturers, October 2005.

Modeling the Fleet Population Effects of the Maine Proposal to Reduce Greenhouse Gas Emissions from Motor Vehicles, prepared for the Alliance of Automobile Manufacturers, October 2005.

Modeling the Fleet Population Effects of the New Jersey Proposal to Reduce Greenhouse Gas Emissions from Motor Vehicles, prepared for the Alliance of Automobile Manufacturers, September 2005.

Modeling the Fleet Population Effects of the Connecticut Proposal to Reduce Greenhouse Gas Emissions from Motor Vehicles, prepared for the Alliance of Automobile Manufacturers, September 2005.

Modeling the Fleet Population Effects of the Vermont Proposal to Reduce Greenhouse Gas Emissions from Motor Vehicles, prepared for the Alliance of Automobile Manufacturers, August 2005.

Modeling the Fleet Population Effects of the New York State Proposal to Reduce Greenhouse Gas Emissions from Motor Vehicles, prepared for the Alliance of Automobile Manufacturers, July 2005.

Initial Review of Potential Expansion of the UK Phase 2 NAP to Additional CO₂ Sources, prepared for the Department for the Environment, Food and Rural Affairs, May 2005.

Environmental and Economic Impacts of the ARB Staff Proposal to Control Greenhouse Gas Emissions from Motor Vehicles, prepared for the Alliance of Automobile Manufacturers, September 2004. Submitted to the California Air Resources Board.

Reviews of Studies Evaluating the Impacts of Motor Vehicle Greenhouse Gas Emissions Regulations in California, for the Alliance of Automobile Manufacturers, September 2004. Submitted to California Air Resources Board.

TXU Activities Regarding Actual and Potential US Air Emissions and Climate Change Policies, prepared for TXU Corporation, September 2004.

Strategies for Chubu Electric Power Co., Ltd., to Take Advantage of Opportunities Under Greenhouse Gas Emissions Trading Programs, in collaboration with Japan NUS Co., Lt, for Chubu Electric Power Co., Ltd, January 2004.

Impacts of ZEV Sales Mandate on California Motor Vehicle Emissions: Responses to Comments of Air Resource Board Staff and Related Documents Provided as Part of the 15-Day Notice (with Sierra Research, Inc.), prepared for the Alliance of Automobile Manufacturers, November 2001.

KEPCO's Role in a Greenhouse Gas Emissions Trading Program, prepared for Kansai Electric Power Company, February 2001.

International Carbon Emissions Trading Practices: Review of Recent Literature, prepared for Chubu Electric Power Company, February 2001.

The Timing of Plant Replacement and the Cost-Effectiveness of CO₂ Reductions from Two Canadian Utilities, prepared for Ontario Hydro and TransAlta Corporation, July 1996.

Strategic Environmental Issues Facing Fossil-Fired Electric Generating Plants in Canada, draft prepared for Ontario Hydro and TransAlta Corporation, June 1996.

Scoping Study to Assess the External Costs of Electric Utility Resource Selection in Minnesota, prepared for Otter Tail Power Company with assistance from Systems Applications International, March 1993.

Preliminary Draft Scoping Study to Assess Residual Emissions Valuation in Alberta, prepared for TransAlta Utilities Corporation, September 1992.

Distributional Effects of Economic Instruments for Environmental Policy, prepared for the U.S. Environmental Protection Agency and the Organization for Economic Cooperation and Development, May 1992.

Tradable Permits and Other Economic Incentives for Environmental Protection, prepared for The Canadian Electrical Association and presented at a Workshop on Tradable Permits, June 1990.

B. Economic Impact Assessment

Environmental Costs and Economic Impacts of Two Resource Cases for the First Amendment to the 2021 Integrated Resource Plan, prepared for Nevada Power Company, March 2022.

Environmental Costs and Economic Impacts of the 2021 Integrated Resource Plan, prepared for NV Energy, May 2021.

Environmental Costs and Economic Impacts of Additional Resource Cases for the Fourth Amendment to the 2018 Integrated Resource Plan: Supplemental Report, prepared for NV Energy, October 2020.

Impacts of Digital Video Piracy on the U.S. Economy, prepared for the U.S. Chamber of Commerce, June 2019.

Economic Contributions of EmblemHealth and AdvantageCare Physicians to the New York City and New York State Economies, prepared for EmblemHealth, October 2018.

Contributions of Oak Meadow Energy to the Economies of Cook County and the State of Illinois, prepared for Advanced Power, September 2018.

Environmental Costs and Economic Impacts of the 2018 Integrated Resource Plan, prepared for Nevada Power Company, June 2018.

Methodology for Evaluating the Macroeconomic Impacts of Energy Efficiency Programs using REMI, prepared for New York State Energy Research and Development Administration, August 2017.

Impacts of Potential Aluminum Tariffs on the U.S. Economy, prepared for Emirates Global Aluminum, June 2017.

Airbnb's Global Support to Local Economies: Output and Employment, prepared for Airbnb, March 2017.

Economic Impacts of EPA Portland Harbor Superfund Remedial Alternatives, prepared for the Portland Harbor Sustainability Project, September 2016.

Environmental Costs and Economic Impacts of 100 MW Generic Technology/Resource Options (Supplemental Report to 2016 IRP), prepared for Sierra Pacific Power Company, September 2016.

Environmental Costs and Economic Impacts of the 2016 Integrated Resource Plan, prepared for Sierra Pacific Power Company, June 2016.

Environmental Costs and Economic Impacts of the 2015 Integrated Resource Plan, prepared for Nevada Power Company, June 2015.

Economic Impacts of a 65 ppb National Ambient Air Quality Standard for Ozone, Executive Summary, prepared for National Association of Manufacturers, February 2015.

Assessing Economic Impacts of a Stricter National Ambient Air Quality Standard for Ozone, prepared for National Association of Manufacturers, July 2014.

Environmental Costs and Economic Impacts of the Emissions Reduction and Capacity Replacement Plan, prepared for NV Energy Inc., May 2014.

Economic Implications of Recent and Anticipated EPA Regulations Affecting the Electricity Sector, prepared for American Coalition for Clean Coal Electricity, October 2012.

Potential Impacts of EPA Air, Coal Combustion Residuals, and Cooling Water Regulations, prepared for the American Coalition for Clean Coal Electricity, September 2011.

Socioeconomic Gains to Pennsylvania of the Muddy Run Pumped Storage Project and the Conowingo Hydroelectric Project, prepared for Exelon Generation Company, LLC, November 2012.

Socioeconomic Gains to Maryland of the Muddy Run Pumped Storage Project and the Conowingo Hydroelectric Project, prepared for Exelon Generation Company, LLC, November 2012.

Effects of a Gas-to-Liquid Facility on the Alberta and Canadian Economies, prepared for Sasol Ltd and Talisman Energy, March 2012.

Effects on State Economies of Tightening of 8-Hour Ozone NAAQS, prepared for American Petroleum Institute, May 2010.

Impacts of Continental Airlines Operations on the New York- New Jersey Regional Economy, prepared for Continental Airlines, November 2009.

Potential Jobs Impacts of Energy Efficiency Expenditures, prepared for Commonwealth Edison, December 2008.

Potential Jobs Impacts of "Smart Grid" Implementation, prepared for Commonwealth Edison, December 2008.

Potential Jobs Impacts of Electric Utility Asset Renewal, prepared for Commonwealth Edison, December 2008.

Economic Impact of Delta's JFK Presence, prepared for Delta Air Lines, July 2008.

The Flemings Strategy for Grand Bahama Island (contributor), prepared for Global Fulfillment Services Ltd., July 2008.

Estimated Attainment Costs and Economic Impacts in Selected Regions of Proposed Revisions to the EPA 8-Hour Ozone Standard, prepared for National Association of Manufacturers, January 2008.

The Economic Impacts of Attaining the 8-Hour Ozone Standard: Cleveland Case Study, prepared for the American Petroleum Institute, October 2005.

The Economic Impacts of Attaining the 8-Hour Ozone Standard: Philadelphia Case Study, prepared for the American Petroleum Institute, September 2005.

The Past, Present, and Future Socioeconomic Effects of the Niagara Power Project, prepared for the New York Power Authority, August 2005.

Environmental and Economic Impacts of the ARB Staff Proposal to Control Greenhouse Gas Emissions from Motor Vehicles, prepared for the Alliance of Automobile Manufacturers, September 2004. Submitted to California Air Resources Board.

Impacts of Alternative California Air Resources Board Tier 3 Non-Handheld Exhaust Emission Proposals on the California Economy, prepared for Briggs & Stratton Corporation, September 2003.

Impacts of Eliminating the Withholding Tax on International Wagering in U.S. Pools, prepared for National Thoroughbred Racing Association, May 2003.

Impacts of a Premature Shutdown of Indian Point: Updated Results and Comments on February 2003 Report by Synapse Energy Economics Inc., prepared for Entergy Nuclear General Company, April 2003.

Study of the Impact of the Future Chemicals Policy, prepared for Union des Industries Chimiques of France, April 2003.

Economic Projections Relevant to Traffic Demand Projections for the Chicago Skyway Project, prepared for Wilbur Smith Associates, March 2003.

Assessing the Potential Indirect Effects of Electricity Infrastructure on Regional Growth Patterns, prepared for Southern California Edison, November 2002.

Economic Benefits of PSEG Power Facilities to Bergen County, prepared for PSEG Power Development LLC, April 2002.

The Economic Benefits of the Whitecap Energy System to the Chicago Region, prepared for Whitecap Energy System LLC, January 2001

Evaluation of the Economic Impacts of Proposed Development of the Galleria at Long Wharf in New Haven, Connecticut, prepared for Cowdery, Ecker & Murphy, L.L.C., July 2000.

Contributions of Continental Airlines' Hopkins Hub to the Economy of the Cleveland Metropolitan Area, prepared for Continental Airlines, June 2000.

Contributions of Continental Airlines' Newark Hub to the Economy of Newark/New Jersey/New York City, prepared for Continental Airlines, March 2000.

Critical Review of, Economic Impacts of On Board Diagnostic Regulations, prepared for Alliance of Automobile Manufactures, January 2000.

Economic Benefits of Barajas Airport to the Madrid Region and the Neighboring Communities, prepared on behalf of the Spanish Government, January 1999.

Northwest Regional Jetport: Traffic Forecast and Economic Impact, prepared for and with Mercer Management Consulting, September 1998

Impacts on the Hawaii Economy of Alternative Resource Plans for Oahu, prepared for Hawaiian Electric Company, December 1997.

Economic and Environmental Effects of the Maritimes & Northeast Pipeline Project in New Hampshire, with assistance from the Center for Business and Economic Research at the University of Southern Maine, E.H. Pechan & Associates, Inc., and Rose Communications, Inc., prepared for The Maritimes & Northeast Pipeline Project, March 1997.

Economic and Environmental Effects of the Maritimes & Northeast Pipeline Project in Massachusetts, with assistance from the Center for Business and Economic Research at the University of Southern Maine, E.H. Pechan & Associates, Inc., and Rose Communications, Inc., prepared for The Maritimes & Northeast Pipeline Project, January 1997.

Economic and Environmental Effects of the Maritimes & Northeast Pipeline Project, with assistance from the Center for Business and Economic Research at the University of Southern Maine, E.H. Pechan & Associates, Inc., and Rose Communications, Inc., prepared for The Maritimes & Northeast Pipeline Project, November 1996.

Contributions of American Airlines to the Economy of Dade County, prepared for American Airlines, October 1996.

Socioeconomic Effects of Alternative Electric Utility Resources, prepared for Northern States Power Company, June 1995.

Contributions of the Chicago Airport System to the Chicago Regional Economy, prepared for the City of Chicago Department of Aviation, March 1993.

An Economic Analysis of the RECLAIM Trading Program for the South Coast Air Basin, prepared for the Regulatory Flexibility Group and the California Council for Environmental and Economic Balance, March 1992.

Tax Impacts of Alternative Future Airport Systems for the Chicago Region, prepared for the City of Chicago Department of Aviation, January 1992.

Economic Impacts of Alternative Airport Systems for the Chicago Region, prepared for the City of Chicago Department of Aviation, November 1991.

The Lake Calumet Airport and Chicago's Economic Future, prepared for the Lake Calumet Airport Advisory Committee, September 1991.

Updated Economic Impacts of Alternative Future Airport Systems, prepared for the City of Chicago Department of Aviation, September 1991.

The Impact on Ontario Hydro of Emissions Trading for Nitrogen Oxides: A Preliminary Analysis, prepared for Ontario Hydro, December 1990.

The Economic Impacts of Locating a New Airport in the Lake Calumet Area, prepared for the City of Chicago Department of Aviation, January 1990.

Economic Impacts of the Cranberry Industry in Massachusetts, prepared for The Cranberry Institute, November 1989.

Economic Impacts of Rule 1135 Proposed by the South Coast Air Quality Management District, prepared for the Southern California Utility Air Group, May 1989.

Economic Impacts of the Draft Air Quality Management Plan Proposed by the South Coast Air Quality Management District, prepared for the California Council for Environmental and Economic Balance, December 1988.

C. Air Quality

Environmental Costs and Economic Impacts of Two Resource Cases for the First Amendment to the 2021 Integrated Resource Plan, prepared for Nevada Power Company, March 2022.

Environmental Costs and Economic Impacts of the 2021 Integrated Resource Plan, prepared for NV Energy, May 2021.

Environmental Costs and Economic Impacts of Additional Resource Cases for the Fourth Amendment to the 2018 Integrated Resource Plan: Supplemental Report, prepared for NV Energy, October 2020.

Environmental Costs and Economic Impacts of Additional Resource Cases for the Fourth Amendment to the 2018 Integrated Resource Plan, prepared for NV Energy, July 2020.

Environmental Costs and Economic Impacts of Additional Resource Cases for the Third Amendment to the 2018 Integrated Resource Plan, prepared for NV Energy, June 2019.

Environmental Costs and Economic Impacts of the 2018 Integrated Resource Plan, prepared for Nevada Power Company, June 2018.

Environmental Costs and Economic Impacts of 100 MW Generic Technology/Resource Options, prepared for Sierra Pacific Power Company, September 2016.

Environmental Costs and Economic Impacts of the 2016 Integrated Resource Plan, prepared for Sierra Pacific Power Company, June 2016.

Environmental Costs and Economic Impacts of the 2015 Integrated Resource Plan, prepared for Nevada Power Company, June 2015.

EPA Regulatory Impact Analysis of Proposed Federal Ozone Standard: Potential Concerns Related to EPA Compliance Cost Estimates, prepared for National Association of Manufacturers, March 2015.

Economic Impacts of a 65 ppb National Ambient Air Quality Standard for Ozone, Executive Summary, prepared for National Association of Manufacturers, February 2015.

Assessing Economic Impacts of a Stricter National Ambient Air Quality Standard for Ozone, prepared for National Association of Manufacturers, July 2014.

Environmental Costs and Economic Impacts of the Emissions Reduction and Capacity Replacement Plan, prepared for NV Energy Inc., May 2014.

Cost-Effectiveness Analysis of Alternative Woodstove New Source Performance Standards, prepared for Hearth, Patio and Barbecue Association, May 2014.

Assessment of EPA Economic Analyses for Proposed Wood Heater New Source Performance Standards, prepared for Hearth, Patio and Barbecue Association, May 2014.

Cost-Effectiveness Analysis of Alternative Hydronic Heater New Source Performance Standards, prepared for Hearth, Patio and Barbecue Association, May 2014.

Environmental and Economic Impacts of the First Amendment Supplemental Filing to the 2009 Integrated Resource Plan, prepared for Nevada Power Company, October 2011.

Environmental Costs and Economic Impacts of the Second Amendment to the 2009 Integrated Resource Plan, prepared for Nevada Power Company, August 2011.

Environmental Costs and Economic Impacts of the 2010 Integrated Resource Plan, prepared for Sierra Pacific Power Company, July 2010.

Environmental Costs and Economic Impacts of the 2009 Integrated Resource Plan, prepared for Nevada Power Company, February 2010.

Economic Analysis of Proposed U.S. EPA Biocide Data Requirements, prepared for The American Chemistry Council, March 2009.

Environmental Costs and Economic Benefits of Electric Utility Resource Selection, prepared for Nevada Power Company, March 2009.

Customer Behavior in Response to the 2007 Heavy-Duty Emission Standards: Implications for the 2010 NOx Standard, prepared for Navistar International Corporation, November 2008.

Environmental Costs and Economic Benefits of Electric Utility Resource Selection, prepared for Nevada Power Company, May 2008.

Evaluation of Potential Attainment Costs and Economic Impacts under a Potential Revised EPA 8-Hour Ozone Standard, prepared for the National Association of Manufacturers, January 2008.

Evaluation of a Voluntary SO₂ Trading Program for the Pulp and Paper Sector, prepared for the American Pulp and Paper Association, February 2007.

An Evaluation of Alternative Approaches to Reducing Pennsylvania Mercury Emissions, prepared for PPL Corporation, August 2006.

An Evaluation and Empirical Analysis of a National Cap-and-Trade Program to Reduce Montana Mercury Emissions, prepared for PPL Corporation, July 2006.

Environmental Costs and Economic Benefits of Electric Utility Resource Selection, prepared for Nevada Power Company, June 2006.

Economic Assessments of Alternative Emission Standards for Small Nonroad Engines, with Air Improvement Resource, Inc. and Sierra Research, Inc., prepared for Briggs and Stratton Corporation, June 2006.

Preliminary Sector Cost Estimates for Potential Emissions Abatement Regulation, prepared for the American Chemistry Council, January 2006.

Economic and Environmental Impacts of EPA's 2007 Heavy-Duty Emissions Standards, prepared for the Engine Manufacturers Association, January 2005.

Evaluation of the Costs of Potential National Caps on Sulphur Dioxide Emissions and Nitrogen Oxide Emissions from Facilities in the Pulp and Paper Industry, prepared for the American Forest & Paper Association, March 2004.

Cost-Effectiveness Analyses of Alternative California Air Resources Board Tier 3 Non-Handheld Exhaust Emission Proposals, prepared for Engine Manufacturers Association and Outdoor Power Equipment Institute, September 2003.

Fleetwide Emissions and Cost-Effectiveness of the Pull-Ahead Requirements for Heavy Heavy-Duty Diesel Engines: Response to Comments Provided by ICF Consulting and Sonoma Technology, Inc., prepared for Detroit Diesel Corporation, July 2002.

Economic Assessments of Alternative Emission Standards for Snowmobile Engines, prepared for International Snowmobile Manufacturers Association, July 2002.

Fleetwide Emissions and Cost-Effectiveness of the Consent Decree Pull-Ahead Requirements for Heavy-Duty Diesel Engines, prepared for Detroit Diesel Corporation, May 2002.

Agenda for the Future: Expanding Policy Innovations to Reconcile Energy and Environmental Objectives, prepared for Edison Electric Institute, March 2001.

Impact of Alternative ZEV Sales Mandates on California Motor Vehicle Emissions: A Comprehensive Study (with Sierra Research, Inc.), prepared for the Alliance of Automobile Manufacturers and the Association of International Automobile Manufacturers, January 2001.

Impacts of the Zero Emission Vehicle Mandate on the California Economy, prepared for General Motors Corporation, January 2001.

Review of ADL and UCS Presentations to the California Air Resources Board Regarding the ZEV Mandate, prepared for the Alliance of Automobile Manufacturers and the Association of International Automobile Manufacturers, January 2001.

The Effects of Environmental Regulations on United States Nuclear Power Generation, prepared for Kansai Electric Power Company, January 2001.

Economic Assessment of the Cost-Effectiveness of Alternative MACT Standards for the Metal Coil Surface Coating Industry, prepared for National Coil Coater Association, September 2000.

Addendum Report: Economic Assessment of the Cost-Effectiveness of Alternative Phase 2 Regulations for Handheld Engines, prepared for Husqvarna AB, Husqvarna Forest & Garden Products Co., and Frigidaire Home Products, November 1999.

Economic Assessment of the Cost-Effectiveness of Alternative Phase 2 Regulations for Handheld Engines, prepared for Husqvarna AB, Husqvarna Forest & Garden Products Co., and Frigidaire Home Products, September 1999.

Energy-Environment Policy Integration and Coordination Study (E-EPIC) Phase 1 Executive Report (Contributor), prepared for the Electric Power Research Institute, February 1999.

Economic Analyses of Alternative California Standards for Exhaust Emissions from Marine Engines, prepared for the National Marine Manufacturers Association, October 1998.

Detailed Comments of the Alliance for Constructive Air Policy ("ACAP") on EPA's Supplemental Notice of Proposed Rulemaking Regarding a Model NO_x Cap-and-Trade Rule, submitted by ACAP, June 1998.

Comments on EPA's Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, prepared for the Equipment Manufacturers Institute, December 1997.

Economic Evaluation of Regulations on Exhaust Emissions from Large Nonroad, Compression Ignition Engines, prepared for the Engine Manufacturers Association and the Equipment Manufacturers Institute, October 1997.

Economic Evaluation of Alternative Regulations of Exhaust Emissions from Small Utility Engines, prepared for Briggs & Stratton Corporation, February 1996

The New York State Environmental Externalities Cost Study: An Overview of Key Elements and Issues, prepared for the Electric Power Research Institute, April 1995.

External Benefits from Increasing Electric Vehicles in the Los Angeles Department of Water and Power Service Territory, prepared for the Los Angeles Department of Water and Power, January 1995.

Consideration of Environmental Externality Values in Minnesota Electric Utility Resource Planning, prepared for Northern States Power Company, November 1994.

Evaluation of Phase I Standards for Small Utility Engines, prepared for Briggs & Stratton Corporation, November 1994.

Evaluation of Additional Tier I Standards for 0-25 HP Engines, prepared for Briggs & Stratton Corporation, October 1994.

Key Issues in the Design of Emission Trading Programs to Reduce Ground-Level Ozone, prepared for Electric Power Research Institute, July 1994.

Environmental Externality Policies in New York State: Comments on the 1994 Draft State Energy Plan, prepared for the New York Power Pool, April 1994.

Environmental Considerations in Power Plant Licensing Decisions in Florida, prepared for the Center for Energy and Economic Development, April 1994.

The Benefits of Reducing Emissions of Nitrogen Oxides Under Title IV of the 1990 Clean Air Act Amendments, prepared for the U.S. Environmental Protection Agency Office of Policy, Planning and Evaluation, Air Policy Branch, March 1994.

Scoping Study for a Regional Visibility Trading Program, prepared for Electric Power Research Institute, Energy Analysis Program, February 1994.

Comments on RCG/Hagler, Bailly, Inc. Revised Draft Task 3 Methodological Report, prepared for Empire State Electric Energy Research Company, February 1994.

A Framework for the Empirical Evaluation of Externality Adders for Electric Utilities, prepared for Electric Power Research Institute, Integrated Systems Division, January 1994.

The Environmental and Economic Benefits of Electricity: Positive Externalities and Other Impacts, prepared for Electric Power Research Institute, Integrated Systems Division, December 1993.

External Costs of Electric Utility Resource Selection in Northern Nevada, prepared for Sierra Pacific Power Company with assistance from Systems Applications International, December 1993.

Economic Evaluation of Alternative Strategies for Regulating Marine Engine Emissions, prepared for the National Marine Manufacturers Association, October 1993.

Consideration of Environmental Externalities in New York Electric Utility Decisions, prepared for the New York Power Pool, October 1993.

Emissions Trading Options for Marine Engine Manufacturers, preliminary results prepared for National Marine Manufacturers Association, May 1993.

Comments on RCG/Hagler, Bailly, Inc. Draft Task 3 Methodological Report, prepared for Empire State Electric Energy Research Corporation, April 1993.

Internalization of Externalities from Electric Utility Generation in Alberta, draft prepared for TransAlta Utilities Corporation, March 1993.

External Costs of Electric Utility Resource Selection in Nevada, prepared for Nevada Power Company, March 1993.

Valuation of Air Pollution Damages, prepared for Southern California Edison Company, March 1992.

Adding Rail, Bus, and Fleet Sources to the Regional Clean Air Incentives Market (RECLAIM) Program: A Preliminary Analysis, prepared for Southern California Edison, March 1992.

Market-Based Approaches to Managing Air Emissions in Alberta, prepared for Alberta Energy, Alberta Environment and Canadian Petroleum Association, February 1991.

Using Emissions Trading to Reduce Ground-Level Ozone in Canada: A Feasibility Analysis, prepared for Environment Canada, November 1990.

Market-Based Approaches to Reduce the Cost of Clean Air in California's South Coast Basin, prepared for California Council for Environmental and Economic Balance, November 1990.

Addressing Canada's Ozone Problem: Recommendations for a Cost-Effective Strategy for Controlling Emissions of Nitrogen Oxides and Volatile Organic Compounds, prepared for TransAlta Utilities Corporation and submitted to the Federal/Provincial Long-Range Transport of Air Pollutants Steering Committee, April 1990.

Benefits of the 1989 Air Quality Management Plan for the South Coast Air Basin: A Reassessment, prepared for the California Council for Environmental and Economic Balance, March 1990.

Preliminary Comments on Economic Assessment of the Health Benefits from Improvements in Air Quality in the South Coast Air Basin, prepared for California Council for Environmental and Economic Balance, August 1989.

“Response to ‘Review of CCEEB-NERA Study’ Concerning the Economic Impacts of the Draft Air Quality Management Plan,” prepared for the California Council for Environmental and Economic Balance, submitted to the South Coast Air Quality Management District, March 1989.

Comments on the Draft 1988 Air Quality Management Plan and the Draft Environmental Impact Report Issued by the South Coast Air Quality Management District in September 1988, prepared for the California Council for Environmental and Economic Balance, submitted to the South Coast Air Quality Management District, October 1988.

D. Water Quality and Natural Resources

Social Benefits Evaluation of Entrainment Reducing Technologies at Browns Ferry Nuclear Plant, prepared for ENERCON on behalf of TVA, January 2022.

Social Costs and Compliance Costs of Entrainment Reducing Technologies at Browns Ferry Nuclear Plant Based on Adjustments of Facility Costs, prepared for ENERCON on behalf of TVA, January 2022.

Economic Analyses of Alternative Technologies and Operational Measures Related to 316(b) Regulation Browns Ferry Nuclear Plant. Contributions to Chapter 10 and Chapter 11 of 40 CFR 122.21(r) Submittals for SPS, prepared for Dominion Energy, February 2020.

Economic Analyses of Alternative Technologies and Operational Measures Related to 316(b) Regulation at Surry Power Station (SPS). Contributions to Chapter 10 and Chapter 11 of 40 CFR 122.21(r) Submittals for SPS, prepared for Dominion Energy, February 2020.

Economic Analyses of Alternative Technologies and Operational Measures Related to 316(b) Regulation at North Anna Power Station (NAPS). Contributions to Chapter 10 and Chapter 11 of 40 CFR 122.21(r) Submittals for NAPS, prepared for Dominion Energy, January 2019.

Economic Costs of Entrainment Reduction Technologies at B.L. England Generating Station, prepared for AKRF, Inc., January 2018.

Economic Benefits of Entrainment Reduction Technologies at B.L. England Generating Station, prepared for AKRF, Inc., January 2018.

Economic Evaluation of Two Entrainment Reduction Technologies at Merrimack Station, prepared for Public Service Company of New Hampshire (PSNH), December 2017.

Non-use Benefits of Entrainment Reduction Technologies at B.L. England Generating Station, prepared for AKRF, Inc., October 2017.

Benefit-Cost Analysis of Plume-abated Mechanical Draft Cooling Towers. Chapter 5 in ADDENDUM to the Comprehensive Evaluation of Cooling Water System Alternatives at Millstone Power Station (MPS), prepared for Dominion Energy, April 2017.

Economic Analyses of Alternative Technologies and Operational Measures Related to 316(b) Regulation at Millstone Power Station (MPS). Contributions to Chapter 10 and Chapter 11 of 40 CFR 122.21(r) Submittals for MPS, prepared for Dominion Energy, April 2017.

Economic Analyses of Permanent Mandatory Summertime Outages at IPEC, prepared for Entergy Nuclear Indian Point 2, LLC, and Entergy Indian Point 3, LLC, June 2015.

Economic Costs of Technologies to Reduce Impingement and Entrainment at Bridgeport Harbor Station, prepared for Public Service Enterprise Group (PSEG), March 2015.

Economic Benefits of Technologies to Reduce Impingement and Entrainment at Bridgeport Harbor Station, prepared for Public Service Enterprise Group (PSEG), March 2015.

Cost-Effectiveness Analysis of Scrubber Wastewater Alternatives at Merrimack Station, prepared for Public Service of New Hampshire, October 2014.

Impacts to the New York State Electricity System if Indian Point Energy Center Were Not Available, prepared for Entergy Nuclear Indian Point 2, LLC, and Entergy Indian Point 3, LLC, December 2013.

Benefits and Costs of Cylindrical Wedgewire Screens and Cooling Towers at IPEC, Prepared for Entergy Nuclear Indian Point 2, LLC and Entergy Nuclear Indian Point 3, LLC, December 2013.

Wholly Disproportionate” Assessments of Cylindrical Wedgewire Screens and Cooling Towers at IPEC, prepared for Entergy Nuclear Indian Point 2, LLC and Entergy Nuclear Indian Point 3, LLC, December 2013.

Cost-Effectiveness Analyses of EPA’s Proposed Effluent Limitations Guidelines and Standards for Steam Electric Power Plants, prepared for Utility Water Act Group, September 2013.

EPA Proposed Effluent Guidelines: Compliance Costs, Electricity Sector Costs and Coal Retirements, prepared for the American Coalition for Clean Coal Electricity, September 2013.

Benefits and Costs of Cylindrical Wedgewire Screens at Indian Point Energy Center, prepared for Entergy Nuclear Indian Point 2, LLC and Entergy Nuclear Indian Point 3, LLC, March 2013.

Benefit-Cost Analysis of Alternative Technologies and Operational Measures. Chapter 9 in Comprehensive Evaluation of Cooling Water System Alternatives at Millstone Power Station (MPS), prepared for Dominion Resource Services, Inc., August 15, 2012.

Comments on EPA's Notice of Data Availability for §316(b) Stated Preference Survey, prepared for Utility Water Act Group and Edison Electric Institute, July 2012.

Potential Energy and Environmental Impacts of Denying Indian Point's License Renewal Applications, prepared for Entergy Nuclear Operations Inc., March 2012.

Preliminary Economic Analysis of Cooling Water Intake Alternatives at Merrimack Station, prepared for Public Service of New Hampshire, February 2012.

Comments on Economic Issues Related to EPA's Proposed Regulations for Cooling Water Intake Structures at Existing Facilities, prepared for Utility Water Act Group, August 2011.

Cost-Benefit Comparisons of Fish-Protection Alternatives for AES Cayuga, prepared for AES Corporation, January 2011.

Comments on EPA's Proposed Survey to Estimate the Potential Benefits of Alternative Cooling Water Intake Policies, prepared for American Chemistry Council, American Forest & Paper Association, American Petroleum Institute, and Utility Water Act Group, September 2010.

Cost-Benefit Analysis for Fish Impingement and Entrainment Reduction at Pickering Nuclear Generating Station, prepared for Ontario Power Generation, Inc., December 2009.

Preliminary Costs and Benefits of Cooling Water Intake Alternatives for Mandalay and Ormond Beach Generating Stations, prepared for RRI Energy, Inc., September 2009.

Preliminary Costs and Benefits of California Draft Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling, prepared for California Council for Environmental and Economic Balance, September 2009.

Economic Assessment of Installing Wedgewire Screens at Point Beach Nuclear Power Station, prepared for Florida Power & Light Point Beach Nuclear Station, February 2009.

AES Somerset Generating Station Comprehensive Biological Requirements and Technical Review Report, prepared for AES Somerset LLC, January 2009.

Economic Assessment of Fish-Protective Alternatives at Pilgrim Nuclear Power Station, prepared for Entergy Nuclear Generation Company, June 2008.

Social Costs of Alternative Cooling Procedures at Vermont Yankee Nuclear Power Station, prepared for Entergy Nuclear Vermont Yankee LLC, February 2007.

Assessment of Alternative Intake Technologies: Costs and Benefits of Fish Protection Alternatives at the Salem Facility, prepared for Public Service Electric & Gas Incorporated, January 2006.

White Paper on the Use of Benefit-Cost Analysis in Site-Specific 316(b) Decisions Under the Clean Water Act, prepared for PSEG and Entergy, May 2003.

Valuation of Power Costs in Assessing the Costs of Alternatives Under Section 316(b) of the Clean Water Act, prepared for Edison Electric Institute, August 2002.

Economic Evaluation of the Habitat Replacement Cost Methodology in the U.S. EPA's 316(b) Benefits Case Study for Pilgrim Station, prepared for Entergy Nuclear Generating Company, August 2002.

Economic Evaluation of the Delaware Estuary Case Study in the U.S. EPA's 316(b) Existing Facilities Benefits Case Studies, prepared for Public Service Electric and Gas Company, August 2002.

Mercer Generating Station Supplemental 316(b) Report, prepared for Public Service Electric and Gas Company, December 2000.

Economic Evaluation of EPA's Proposed Rules for Cooling Water Intake Structures for New Facilities, prepared for Utilities Water Act Group, November 2000.

Costs and Benefits of Fish Protection Alternatives at the Salem Facility, prepared for Public Service Electric and Gas Company, March 1999.

Costs and Benefits of Alternatives for Modifying Cooling Water Intake at the Hudson Facility, prepared for Public Service Electric and Gas Company, November 1998.

E. Transportation and Other Infrastructure

Forecasts of Transit Indices for the Indiana Toll Road Based on the CPI and Nominal GDP per Capita, prepared for potential bidder, December 2005.

Socioeconomic Forecasts for the Indiana Toll Road Service Area and the U.S., prepared for potential bidder, December 2005.

Values for Wetlands and Recreational Open Space Relevant to the Harrison, New Jersey Waterfront Site, prepared for AKRF, Inc., October 2005.

Fueling Electricity Growth for a Growing Economy, prepared for Edison Electric Institute, January 2001.

Prospects for the U.S. Nuclear Industry, prepared for Kansai Electric Power Company, January 2001.

Potential Impacts of Environmental Regulations on Diesel Fuel Prices: Evaluation of An Assessment of the Potential Impacts of Proposed Environmental Regulations on U.S. Refinery

Supply of Diesel Fuel, prepared for American Petroleum Institute, August 2000, prepared for the Alliance of Automobile Manufacturers, December 2000.

Evaluation of the Economic Analysis of the Bureau of Land Management's Proposed Regulations on Hardrock Mining, prepared for National Mining Association, July 2000.

Evaluation of the Economic Analysis of the U.S. Forest Service Proposed Rule on Roadless Area Conservation, prepared for the National Mining Association, July 2000.

Benefits and Costs of Underground Conversion of Overhead Distribution Lines in New York State, prepared for New York Electric Utilities, July 1994.

Potential Impacts of the Clean Harbors Proposed Rotary Kiln Incinerator on Aesthetics, Recreation, Tourism and Property Values, prepared for Clean Harbors, Inc., June 1989.

Airport Congestion in the United States, prepared for the UK Department of Transport, May 1989.

III. Testimony in Regulatory and Judicial Proceedings

Before the Public Utilities Commission of Nevada, *First Amendment to 2021 Integrated Resource Plan, Prepared Direct Testimony of David Harrison, Jr.* on behalf of Nevada Power Company d/b/a NV Energy, March 18, 2022.

Before the Public Utilities Commission of Nevada, *2021 Integrated Resource Plan, Prepared Direct Testimony of David Harrison, Jr.* on behalf of Nevada Power Company d/b/a NV Energy, June 1, 2021.

Before the Public Utilities Commission of Nevada, *2021 Joint Integrated Resource Plan, Prepared Rebuttal Testimony of David Harrison, Jr.* on behalf of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy, November 4, 2021.

Before the United States District Court, District of New Hampshire, *Deposition Testimony of David Harrison Jr.* on behalf of Granite Shower Power LLC and GSP Merrimack LLC, April 22, 2021.

Before the Public Utilities Commission of Nevada, *Fourth Amendment to 2018 Joint Triennial Integrated Resource Plan, Prepared Rebuttal Testimony of David Harrison, Jr.* on behalf of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy, February 8, 2021.

Before the Public Utilities Commission of Nevada, *Fourth Amendment to 2018 Joint Triennial Integrated Resource Plan, Prepared Supplemental Direct Testimony of David Harrison, Jr.* on behalf of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy, October 10, 2020.

Before the Public Utilities Commission of Nevada, *Fourth Amendment to 2018 Joint Triennial Integrated Resource Plan, Prepared Direct Testimony of David Harrison, Jr.* on behalf of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy, July 24, 2020.

Before the United States District Court, Northern District of Illinois, Eastern Division, *Deposition Testimony of David Harrison Jr.* on behalf of Navistar International, Corp., and Navistar, Inc., February 25, 2020.

Before the Illinois Commerce Commission, *Rebuttal Testimony and Exhibit of David Harrison, Jr.* on behalf of Dakota Access, LLC, and Energy Transfer Crude Oil Company, LLC, October 22, 2019.

Before the Public Utilities Commission of Nevada, *Third Amendment to 2018 Joint Triennial Integrated Resource Plan, Prepared Direct Testimony of David Harrison, Jr.* on behalf of Nevada Power Company d/b/a/ NV Energy and Sierra Pacific Power Company d/b/a/ NV Energy, June 24, 2019.

Before the Department of Public Utilities of Massachusetts, *Direct Testimony of David Harrison, Jr.* on behalf of Cumberland Farms, Inc., Global Partners LP, The New England Convenience Store and Energy Marketers Association, the Society of Independent Gasoline Marketers or America, and The National Associations of Convenience Stores, March 22, 2019.

Declaration of David Harrison in Support of Chevron U.S.A. 's Motion for a Preliminary Injunction, Chevron U.S.A., Inc., et al. v. Oregon Department of Environmental Quality et al., Circuit Court of the State of Oregon for the County of Marion, December 10, 2018.

Before the Public Utilities Commission of Nevada, *2018 Integrated Resource Plan, Prepared Direct Testimony of David Harrison, Jr.* on behalf of Nevada Power Company d/b/a NV Energy, June 1, 2018.

Before the Public Utilities Commission of Nevada, *Prepared Direct Testimony of David Harrison, Jr. in Response to Procedural Order 1*, on behalf of Sierra Pacific Power Company d/b/a NV Energy, Wednesday, November 30, 2016.

Before the Public Utilities Commission of Nevada, *2016 General Rate Case, Prepared Rebuttal Testimony of David Harrison, Jr.* on behalf of Sierra Pacific Power Company d/b/a NV Energy, November 14, 2016.

Before the Public Utilities Commission of Nevada, *2016 Integrated Resource Plan, Prepared Direct Testimony of David Harrison, Jr.* on behalf of Nevada Power Company d/b/a NV Energy, October 24, 2016.

Before the Public Utilities Commission of Ohio, *Direct Testimony of David Harrison* on behalf of the Dayton Power and Light Company, February 22, 2016.

Before the State of New York Department of Environmental Conservation, *Combined Prefiled Rebuttal of David Harrison, Jr., Ph.D., and Eugene Meehan* on behalf of Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, and Entergy Nuclear Operations, Inc., August 10, 2015.

Before the State of New York Department of Environmental Conservation, *Combined Pre-filed Testimony of David Harrison, Jr., Ph.D., and Eugene Meehan* on behalf of Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, and Entergy Nuclear Operations, Inc., June 26, 2015.

Before the Public Utilities Commission of Nevada, *2015 Integrated Resource Plan, Prepared Direct Testimony of David Harrison, Jr.* on behalf of Nevada Power Company d/b/a NV Energy, June 23, 2015.

Declaration of David Harrison, Jr., Regarding the Likely Impacts of Retiring SO₂ Allowances under the Cross-State Air Pollution Rule, prepared on behalf of Westvaco Corporation, June 12, 2015.

Before the United States House of Representatives, Committee on Oversight and Government Reform, *Prepared Statement of David Harrison, Jr.* at a Hearing on Impacts of U.S. Environmental Protection Agency Regulations, Washington, DC, February 26, 2015.

Before the Public Utilities Commission of Nevada, *2014 Emissions Reduction and Capacity Replacement Plan, Prepared Direct Rebuttal of David Harrison, Jr.* on behalf of Nevada Power Company d/b/a NV Energy, September 6, 2014.

Before the New Hampshire Public Utilities Commission, *Prepared Direct Testimony of David Harrison Jr. and Noah Kaufman*, Docket No. DE 11-250. Public Service Company of New Hampshire. Investigation of Merrimack Station Scrubber Project and Cost Recovery. Submitted on behalf of Public Service of New Hampshire, July 11, 2014.

Before the Public Utilities Commission of Nevada, *2014 Emissions Reduction and Capacity Replacement Plan, Prepared Direct Testimony of David Harrison, Jr.* on behalf of Nevada Power Company d/b/a NV Energy, May 1, 2014.

Before the State of New York Department of Environmental Conservation, *Rebuttal Testimony of David Harrison, Jr.* on behalf of Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, and Entergy Nuclear Operations, Inc., March 28, 2014.

Before the State of New York Department of Environmental Conservation, *Pre-filed Testimony of David Harrison, Jr.* on behalf of Entergy Nuclear Indian Point 2, LLC, Entergy Nuclear Indian Point 3, LLC, and Entergy Nuclear Operations, Inc., February 28, 2014.

Before the Public Utilities Commission of Nevada, 2nd Amendment to the 2010 Integrated Resource Plan, *Pre-filed Direct Testimony of David Harrison, Jr.* on behalf of Sierra Pacific Power Company, August 7, 2012.

Before the Public Utilities Commission of Nevada, *2013-2032 Integrated Resource Plan, Pre-filed Direct Testimony of David Harrison, Jr.* on behalf of Nevada Power Company, June 21, 2012.

Before the United States of America Nuclear Regulatory Commission, before the Atomic Safety and Licensing Board, Testimony of David Harrison Jr. on Contention NYS-37 on behalf of Entergy Nuclear Operations, Inc., March 30, 2012.

Before the Public Utilities Commission of Nevada, *Eleventh Amendment to its 2010-2029 Integrated Resource Plan, Pre-filed Direct Testimony of David Harrison, Jr.* on behalf of Nevada Power Company, February 1, 2010.

Before the Public Utilities Commission of Nevada, *Eleventh Amendment to its 2007-2026 Integrated Resource Plan, Pre-filed Direct Testimony of David Harrison, Jr.* on behalf of Nevada Power Company, March 3, 2009.

Before the Public Utilities Commission of Nevada, *Eighth Amendment to the 2006 - 2025 Integrated Resource Plan, Pre-filed Rebuttal Testimony of David Harrison, Jr.* on behalf of Nevada Power Company, August 26, 2008.

Brief of Amicus Curiae the AEI Center for Regulatory and Market Studies and 33 Individual Economists in Support of Petitioners, submitted to the Supreme Court of the United States. Entergy Corp, PSEG Fossil LLC and PSEG Nuclear LLC, and the Utility Water Act Group, petitioners, v. Riverkeeper Inc. et al., respondents, on writs of certiorari to the United States Court of Appeals for the Second Circuit. July 21, 2008.

Affidavit of David Harrison, Jr., Ph.D., on behalf of AES and Dynegy, Regarding New York State Department of Environmental Conservation's Proposed 6 NYCRR Part 242, CO₂ Budget Trading Program, Revisions To 6 NYCRR Part 200, June 16, 2008.

Before the Public Utilities Commission of Nevada, *Eighth Amendment to the 2007 - 2026 Integrated Resource Plan, Pre-filed Direct Testimony of David Harrison, Jr.* on behalf of Nevada Power Company, May 16, 2008.

Before the Public Utilities Commission of Nevada, *Seventh Amendment to the 2006 Integrated Resource Plan, Pre-filed Direct Testimony of David Harrison, Jr.* on behalf of Nevada Power Company, March 15, 2008.

Affidavit of David Harrison, Jr., Ph.D. in support of Public Service Company of New Hampshire's comments on Department of Environmental Service's Preliminary Responses to Requests for Bonus Carbon Dioxide and Nitrogen Oxides Allowances Pursuant to RSA 125-O and Env-A, September 12, 2007.

Prefiled Testimony of David Harrison, Jr., Ph.D. in support of Entergy Nuclear Vermont Yankee, LLC, on behalf of Entergy Nuclear Vermont Yankee LLC, June 22, 2007.

Before the Public Utilities Commission of Nevada, *Application for Approval of the 2008 – 2027 Integrated Resource Plan*, Pre-filed Direct Testimony of David Harrison, Jr. on behalf of Sierra Pacific Power Company, June 20, 2007.

Direct Testimony of David Harrison, Jr., Ph.D., in the Matter of Green Mountain Chrysler Plymouth Dodge Jeep, et al v. Thomas W. Torti, et al (Case No. 05-cv-302), on behalf of Plaintiffs, April 19, 2007, before Hon. William K. Sessions III, Vermont District Court, Burlington, VT.

Affidavit of David Harrison, Jr., Ph.D. in support of Entergy Nuclear Vermont Yankee, LLC's Opposition to Motions to Renew Stay, on behalf of Entergy Nuclear Vermont Yankee LLC, February 27, 2007.

Rebuttal Testimony of David Harrison, Jr., Ph.D., in the Matter of Green Mountain Chrysler Plymouth Dodge Jeep, et al v. Thomas W. Torti, et al (Case No. 05-cv-302), on behalf of Plaintiffs, October 9, 2006.

Supplemental Testimony of David Harrison, Jr., Ph.D., in the Matter of Central Valley Chrysler Jeep, Inc. et al. v. Witherspoon, on behalf of Plaintiffs, October 9, 2006.

Before the Public Utilities Commission of Nevada, *Application for Approval of the Thirteenth Amendment to the 2005 – 2024 Integrated Resource Plan, Environmental Costs and Economic Benefits of Proposed Expansion Plans*, Direct Testimony of David Harrison, Jr. on behalf of Nevada Power Company and Sierra Pacific Power Company, October 3, 2006.

Before the Public Utilities Commission of Nevada, *Application for Approval of the 2007-2026 Integrated Resource Plan, Rebuttal Testimony of David Harrison, Jr.* on behalf of Nevada Power Company, Sept 20, 2006.

Before the Public Utilities Commission of Nevada, *Application for Approval of the 2007-2026 Integrated Resource Plan, Supplemental Testimony of David Harrison, Jr.* on behalf of Nevada Power Company, Sept 8, 2006.

Before the Public Utilities Commission of Nevada, *Application for Approval of the Thirteenth Amendment to the 2005 – 2024 Integrated Resource Plan, Environmental Costs and Economic Benefits of Proposed Expansion Plans*, Pre-filed Direct Testimony of David Harrison, Jr. on behalf of Sierra Pacific Power Company, July 14, 2006.

Before the Public Utilities Commission of Nevada, *Application for Approval of the 2007 – 2026 Integrated Resource Plan, Environmental Costs and Economic Benefits of Proposed Expansion Plans*, Pre-filed Direct Testimony of David Harrison, Jr. on behalf of Nevada Power Company, Docket No. 06-06051, June 30, 2006.

Rebuttal Testimony of David Harrison, Jr., Ph.D., in the Matter of Central Valley Chrysler Jeep, Inc. et al. v. Witherspoon, on behalf of Plaintiffs, June 12, 2006.

Testimony of David Harrison, Jr., Ph.D., in the Matter of Green Mountain Chrysler Plymouth Dodge Jeep, et al v. Thomas W. Torti, et al (Case No. 05-cv-302), on behalf of Plaintiffs, May 18, 2006.

Testimony of David Harrison, Jr., Ph.D., in the Matter of Central Valley Chrysler Jeep, Inc. et al. v. Witherspoon, on behalf of Plaintiffs, May 2, 2006.

Rebuttal Testimony of David Harrison, Jr., Ph.D., in the Matter of the Renewal/Modification of the State Pollution Discharge Elimination System Permit of Dynegy Danskammer Generation Station, on behalf of Dynegy Northeast Generation, Inc., November 7, 2005.

Direct Testimony of David Harrison, Jr., Ph.D., in the Matter of the Renewal/Modification of the State Pollution Discharge Elimination System Permit of Dynegy Danskammer Generation Station, on behalf of Dynegy Northeast Generation, Inc., October 17, 2005.

Prepared Direct Testimony of David Harrison, Jr., Ph.D., on Behalf of the American Electric Power System. In the Matter of the American Electric Power Company, Inc.: File No. 3-11616. December 7, 2004.

Testimony of David Harrison, Jr., in the Matter of the Arbitration Between BASF Corp., Claimant, and Albaugh, Respondent, prepared on behalf of BASF, February 22, 2002.

Affidavit of David Harrison, Jr., on behalf of PSEG Power New York, Inc., Regarding an Application for a Certificate of Environmental Compatibility and Public Need to Construct and Operate a 750-Megawatt Natural Gas-Fired Combined Cycle, Combustion Turbine Generating Facility in the Town of Bethlehem, Albany County, November 30, 2001.

Second Declaration of David Harrison, Jr., in Response to Notice of Availability of Modified Text and Supporting Documents and Information Released on October 31, 2001, prepared on behalf of General Motors, November 2001.

Declaration of David Harrison, Jr., Regarding the Environmental Disbenefits of the California Zero Emission Vehicle Mandate, prepared on behalf of General Motors Corporation, January 2001.

Oral testimony on behalf of plaintiff Stewart Hutchings, et al vs. Connecticut Department of Economic and Community Development and Office of Policy and Management, Superior Court J. D. of Hartford, March 20, 2000.

Supplemental Report Relating to Damages Incurred to Investigate and Remediate the Bound Brook, New Jersey Site on behalf of Cyanamid Co., et al. V. The Aetna Casualty & Surety Co., et al., Civil Action No. PAS-L-8275-91 (NJ Super. Ct. Law Div), December 3, 1999.

Assessment of Economic Values Associated with Alternative Hydrocarbon Emissions Scenarios, prepared on behalf of Toyota Motor Corporation, in the Matter of the Accusation Against Toyota Motor Corporation (MY 1996-1998 Passenger Cars and Light-Duty Trucks with Evaporative Leak Check Diagnostic Systems) Before the California Air Resources Board, Case No. 519, August 30, 1999.

Affidavit of David Harrison, Jr. on behalf of Tecumseh Products Company regarding remedy proposed by EPA Region V for the Sheboygan River and Harbor Site, August 1999.

Reply Comments Submitted to DOT in Response to *Advance Notice of Proposed Policy Regarding Airport Rates and Charges*, Docket No. 29303, prepared on behalf of the Airport Council International-North America, March 1, 1999.

Airports and Competition: Comments Submitted to DOT Request for Comments on Policy Statement, prepared on behalf of the Airport Council International-North America in response to *Advance Notice of Proposed Policy Regarding Airport Rates and Charges*, Docket No. 29303, February 1, 1999.

Rebuttal Report of Plaintiff's Expert in *American Cyanamid Co. et al. v. The Aetna Casualty & Surety Co., et al.*, Civil Action No. PAS-L-8275-91 (N.J. Superior Court Law Division), "Relating to Damages Incurred to Investigate and Remediate the Piney River, Virginia Site," December 21, 1998.

Rebuttal Report of Plaintiff's Expert in *American Cyanamid Co. et al. v. The Aetna Casualty & Surety Co., et al.*, Civil Action No. PAS-L-8275-91 (N.J. Superior Court Law Division), "Relating to Damages Incurred to Investigate and Remediate the Nascolite Site, Cumberland County, New Jersey," December 21, 1998.

Report of Plaintiff's Expert in *American Cyanamid Co. et al. v. The Aetna Casualty & Surety Co., et al.*, Civil Action No. PAS-L-8275-91 (N.J. Superior Court Law Division), "Relating to Damages Incurred to Investigate and Remediate the Piney River, Virginia Site," October 28, 1998.

Report of Plaintiff's Expert in *American Cyanamid Co. et al. v. The Aetna Casualty & Surety Co., et al.*, Civil Action No. PAS-L-8275-91 (N.J. Superior Court Law Division), "Relating to Damages Incurred to Investigate and Remediate the Nascolite Site, Cumberland County, New Jersey," October 28, 1998.

Rebuttal Report of Plaintiff's Expert in *American Cyanamid Co. et al. v. The Aetna Casualty & Surety Co., et al.*, Civil Action No. PAS-L-8275-91 (N.J. Superior Court Law Division), "Relating to Damages Incurred to Investigate and Remediate the Wallingford, Connecticut Site," October 9, 1998.

Rebuttal Report of Plaintiff's Expert in *American Cyanamid Co. et al. v. The Aetna Casualty & Surety Co., et al.*, Civil Action No. PAS-L-8275-91 (N.J. Superior Court Law Division),

“Relating to Damages Incurred to Investigate and Remediate the Bound Brook, New Jersey Site,” September 16, 1998.

Report of Plaintiff’s Expert in *American Cyanamid Co. et al. v. The Aetna Casualty & Surety Co., et al.*, Civil Action No. PAS-L-8275-91 (N.J. Superior Court Law Division), “Relating to Damages Incurred to Investigate and Remediate the Wallingford, Connecticut Site,” August 4, 1998.

Report of Plaintiff’s Expert in *American Cyanamid Co. et al. v. The Aetna Casualty & Surety Co., et al.*, Civil Action No. PAS-L-8275-91 (N.J. Superior Court Law Division), “Relating to Damages Incurred to Investigate and Remediate the Bound Brook, New Jersey Site,” July 16, 1998.

Affidavit on Behalf of Briggs & Stratton Corporation, *Petition for Alternative Emission Standards for Small (0-25 hp) Gasoline Powered Engines*, submitted to the California Air Resources Board, July 1995.

Before the Minnesota Public Utilities Commission, *Considerations in the Development of Externality Values for Greenhouse Gas Emissions*, surrebuttal testimony prepared on behalf of Northern States Power Company In the Matter of the Establishment of Environmental Cost Values, Docket No. E-999/CI-93-583, April 1995.

Before the Minnesota Public Utilities Commission, *Considerations in the Development of Externality Values*, rebuttal testimony prepared on behalf of Northern States Power Company In the Matter of the Establishment of Environmental Cost Values, Docket No. E-999/CI-93-583, March 1995.

Before the Public Service Commission of Nevada, *Environmental Externality Cost Values*, prepared testimony on behalf of Nevada Power Company, Docket No. 94-7001, February 1995.

Before the Minnesota Public Utilities Commission, *Considerations in the Development of Externality Values*, direct testimony on behalf of Northern States Power Company In the Matter of the Establishment of Environmental Cost Values, Docket No. E-999/CI-93-583, November 1994.

Before the Public Utilities Commission of the State of California, *External Benefits from Increasing Electric Vehicles in the Southern California Edison Service Territory*, testimony prepared on behalf of Southern California Edison Company In the Matter of the Order Instituting Investigation and Order Instituting Rulemaking to Develop Rules, Procedures, and Policies Governing Utility Involvement in the Market for Low-Emissions Vehicles, October 1993.

Before the Public Utilities Commission of the State of California, *External Benefits from Increasing Electric Vehicles in the Pacific Gas & Electric Service Territory*, testimony prepared on behalf of Pacific Gas & Electric Company In the Matter of the Order Instituting Investigation

and Order Instituting Rulemaking to Develop Rules, Procedures, and Policies Governing Utility Involvement in the Market for Low-Emissions Vehicles, October 1993.

Before the Public Utilities Commission of the State of California, *External Benefits from Increasing Electric Vehicles in the San Diego Gas & Electric Service Territory*, testimony prepared on behalf of San Diego Gas & Electric Company In the Matter of the Order Instituting Investigation and Order Instituting Rulemaking to Develop Rules, Procedures, and Policies Governing Utility Involvement in the Market for Low-Emissions Vehicles, October 1993.

Affidavit on the Economic Impacts of Chicago Area Airports on the Chicago Regional Economy, prepared on behalf of The City of Chicago in the *People of the State of Illinois et al. v. The City of Chicago et al.*, in the Circuit Court for the Eighteenth Judicial Circuit, DuPage County, Wheaton, Illinois, December 1992.

Before the Public Utilities Commission of the State of California, *Air Quality Issues and Disaggregation of LEV Benefits by Rate Class*, rebuttal testimony prepared on behalf of Southern California Edison Company in the Matter of the Order Instituting Investigation and Order Instituting Rulemaking to Develop Rules, Procedures, and Policies Governing Utility Involvement in the Market for Low-Emissions Vehicles, Docket Nos. I.91-10-029 and R.91-10-028, August 1992.

Before the California Energy Commission ER-92 Hearing on Valuing Air Quality Impacts of Energy Resources, *Revised Damage-Based Values for Residual Emissions Valuation*, (with M. B. Deming), testimony prepared on behalf of Southern California Edison Company, Sacramento, California, May 1992.

Before the State of California Energy Resources Conservation and Development Commission, *Valuing Air Quality Impacts of Alternative Energy Resources*, testimony prepared on behalf of Southern California Edison Company, Docket No. 90-ER-2, March 1992.

Before the California Energy Commission ER-92, *Group I Hearing Issues: Air Quality*, (with Southern California Edison), *1992 Electricity Report*, testimony prepared on behalf of Southern California Edison Company, Docket No. 90-ER-92, submitted by Southern California Edison, November 1991.

Affidavit on Landing Fees at Logan International Airport, prepared on behalf of the defendant in *New England Legal Foundation, et al. v. Massachusetts Port Authority and National Business Aircraft Association, Inc., et al.*, United States District Court, District of Massachusetts, June 1988. (Also submitted to the U.S. Department of Transportation.)

Defendant's Expert Witness Disclosure on Summary of Damages Claimed by the State of Michigan for Fish Killed by the Luddington Pumped Storage Plant, prepared on behalf of Consumers Power Company and The Detroit Edison Company in *Frank J. Kelley, ex rel Michigan Natural Resources Commission; Michigan Department of Natural Resources; and Gordon Guyer, Director of the Michigan Department of Natural Resources v. Consumers Power Company and*

The Detroit Edison Company, Case No. 86-57075-CE in the Circuit Court for the County of Ingham, June 1988.

IV. Presentations

A. Climate Change

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

“Learning from Experience: First Year of the European CO₂ Emissions Trading Scheme,” presented to New Prospects for Climate Change Regulation Panel organized by Harvard Law School, March 10, 2006.

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

“Beyond Cost: Carbon Markets, Electricity Prices and ‘Windfall Profits,’” presented to Electric Utilities Environmental Conference, Tucson, AZ, January 23, 2006.

“European CO₂ Emissions Trading Scheme: First Year Accomplishments and Implications,” presented at an International Emissions Trading Association side event at the 11th Conference of the Parties to the Kyoto Protocol, Montreal, December 5, 2005.

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

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

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

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

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

“How CEPCO Can Gain from CO₂ Trading,” presented to Chubu Electric Power Co., Inc., Nagoya, Japan, November 25, 2003.

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

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

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

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

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

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

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

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

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

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

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

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

“CO₂ Permit Allocations: Evaluation of Alternatives for the EC,” presented to the European Commission, Brussels, Belgium, March 5, 2001.

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

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

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

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

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

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

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

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

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

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

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

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

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

“Emission Trading: Alternative Approaches, Experience and Implications for CO₂,” prepared for the AAMA Climate Change Task Force, Washington, DC, September 27, 1996.

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

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

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

B. Economic Impact Assessments

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

C. Air Quality

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

“NO_x Trading Program to Implement EPA’s SIP Call,” presented to Indiana Department of Environmental Management, Indianapolis, Indiana, May 4, 1998.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

D. Water Quality and Natural Resources

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

AFFIRMATION

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

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

Date: May 31, 2024



DAVID HARRISON

MIKE BEHRENS

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

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

Prepared Direct Testimony of
Mike Behrens

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

A. My name is Mike Behrens. My current position is Vice President and Chief Financial Officer 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” or “NV Energy”). My business address is 6100 Neil Road in Reno, Nevada. I am filing testimony on behalf of the Companies.

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

A. After leaving Ernst & Young as an Audit Manager, I started my utility experience in 2014 with the Companies where I have held various positions. In 2014, I joined the Companies as the Manager of External Financial Reporting responsible for overseeing the preparation of external financial reports including required U.S. Securities and Exchange Commission (“SEC”) filings and Federal Energy Regulatory Commission filings. In 2017, I transitioned to the Manager of Accounting Policy and Special Projects for Berkshire Hathaway Energy Company (“BHE”). In that role, I oversaw the implementation of new accounting guidance

1 across the BHE companies along with assisting in various other projects, including
2 supporting SEC filings. In 2019, I transitioned back to the Companies as the
3 Controller where I was responsible for the general accounting functions,
4 maintenance of the accounting books and records, regulatory accounting
5 compliance, and managing the implementation of accounting guidance related to
6 regulatory issues. In March 2023, I became Vice President and Chief Financial
7 Officer. My statement of qualifications is attached as **Exhibit Behrens-Direct-1**.
8

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

11 A. As Vice President and Chief Financial Officer, my responsibilities include
12 leadership and oversight of the accounting, tax, financial planning, internal audit,
13 treasury, credit and risk related functions. With input from other members of the
14 Companies' leadership team, I direct the Companies' financial policies, including
15 their financing activities and capital structure strategies.
16

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

20 A. Yes. I have provided written testimony in many cases including the most recent
21 Sierra and Nevada Power general rate review proceedings, Docket Nos. 24-02026
22 and 23-06007, respectively. I also testified before this Commission in several other
23 cases including, but not limited to, the Companies' Integrated Resource Plans
24 ("IRP"), Joint Merger Application, Natural Disaster Protection Plans, Expanded
25 Solar Access Program, the ON Line Temporary Rider, and the Economic Recovery
26 Transportation Electrification Plan ("ERTEP").
27

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

A. I sponsor the Financial Plan narrative to the 2024 Joint IRP. In Section II of my direct testimony, I provide an overview of the Preferred and Alternate Plans' capital commitments. Section III of my direct testimony provides a more detailed discussion of the Companies' financial plans associated with the Preferred and Alternate Plans, including capital spending projections, funding requirements and credit metric impacts. I also address the affordability of the forecasted capital expenditures. My direct testimony and the Financial Plan address the financial impacts and customer rate impacts of the Preferred and Alternate Plans reflecting traditional rate making principles. In addition, I support the request for construction work in progress ("CWIP") in rate base for the Greenlink projects and discuss the modeling completed to demonstrate its benefit to customers.

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

A. I am sponsoring the following Exhibits:

Exhibit Behrens-Direct-1 Statement of Qualifications

Exhibit Behrens-Direct-2 (Confidential) Sierra Moody's Downgrade

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

A. Yes. Exhibit Behrens-Direct-2 is confidential because it is Moody's copyrighted material. Further, there are multiple figures in the Financial Plan narrative that are confidential. Specifically, the Companies request confidential treatment of Figures FP-3 and FP-4 in the External Financing Requirements section of the Financial Plan and Figures FP-11 through FP-18 in the Credit Quality section of the Financial Plan. Specific references throughout my direct testimony to forecasted financial

information, including those related to the direct testimony and exhibits of Chris Sarda are also confidential.

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

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

9. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF THE COMMISSION'S REGULATORY OPERATIONS STAFF ("STAFF") OR THE NEVADA ATTORNEY GENERAL'S BUREAU OF CONSUMER PROTECTION ("BCP") TO FULLY INVESTIGATE THE INFORMATION SET FORTH IN THIS FILING?

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

II. PREFERRED AND ALTERNATE PLANS

10. Q. PLEASE IDENTIFY THE INCREMENTAL CAPITAL PROJECTS PROPOSED IN THE COMPANIES' FILING.

A. The Companies' Preferred Plan primarily includes the following capital projects:

- 1) Sierra's construction of a 411 MW peaker plant addition at the Valmy generating facility; and
- 2) Various transmission additions and upgrades.

The Alternate Plan is similar to the Preferred Plan with the exception of the exclusion of the Valmy peaker facilities and its associated transmission projects.

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

A. For Nevada Power, the total incremental capital expenditures requested in this filing occur in years 2025 through 2028 and are estimated to be \$1.1 billion, in the Preferred and Alternate Plans. For Sierra, the total incremental capital expenditures requested in this filing occur in years 2025 through 2031 and are estimated to be \$1.8 billion and \$1.3 billion for the Preferred and Alternate Plans, respectively.

The capital requirements for the Preferred Plan for the entire 2025-2044 period total \$26.7 billion for Nevada Power and \$18.5 billion for Sierra (including Allowance for Funds Used During Construction ("AFUDC")). Over the next five years (2025-2029), capital projections for the Preferred Plan total \$6.4 billion for Nevada Power and \$6.6 billion for Sierra.

The capital requirements for the Alternate Plan for the entire 2025-2044 period total \$27.0 billion for Nevada Power and \$18.0 billion for Sierra (including AFUDC). Over the next five years (2025-2029), capital projections for the Alternate Plan total \$6.5 billion for Nevada Power and \$6.6 billion for Sierra.

The capital expenditures (including AFUDC) of the Preferred and Alternate Plans are shown below in **Figure Behrens-Direct-1** for Nevada Power and **Figure Behrens-Direct-2** for Sierra. These figures were constructed using the capital expense recovery ("CER") model.

FIGURE BEHRENS-DIRECT-1
NEVADA POWER
CAPITAL EXPENDITURES (\$ - MILLIONS)

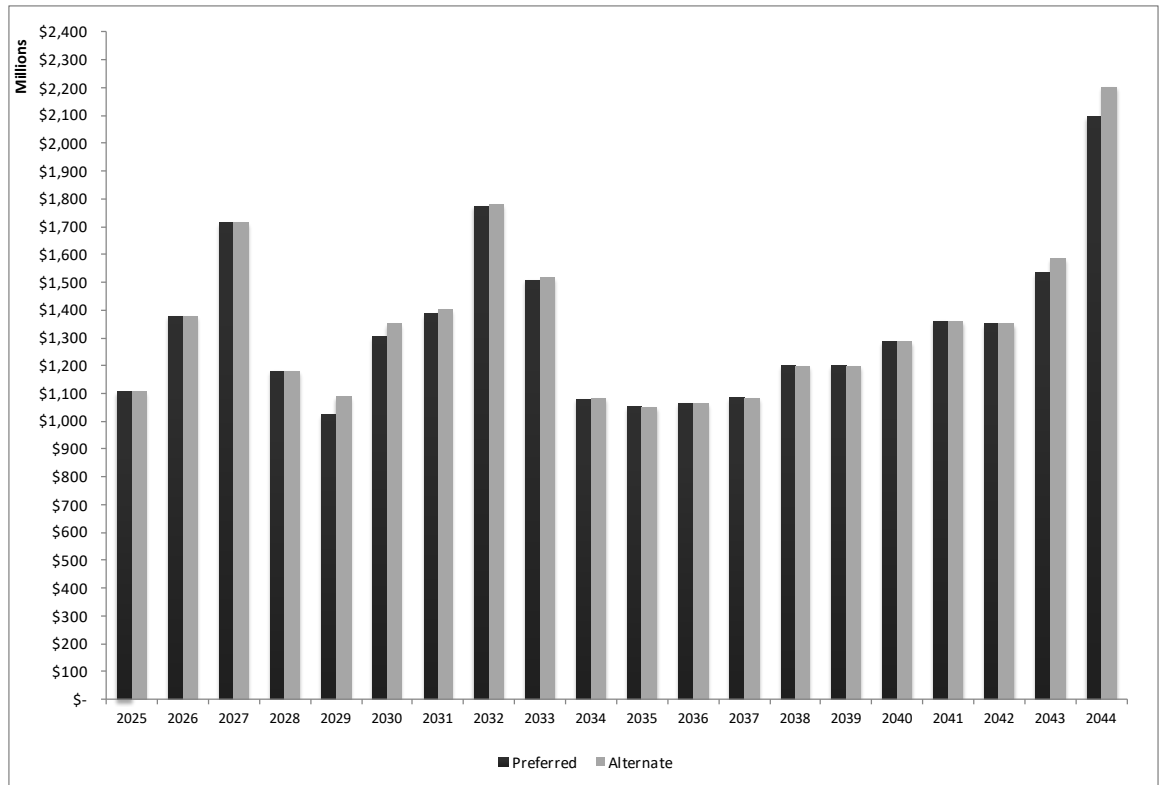
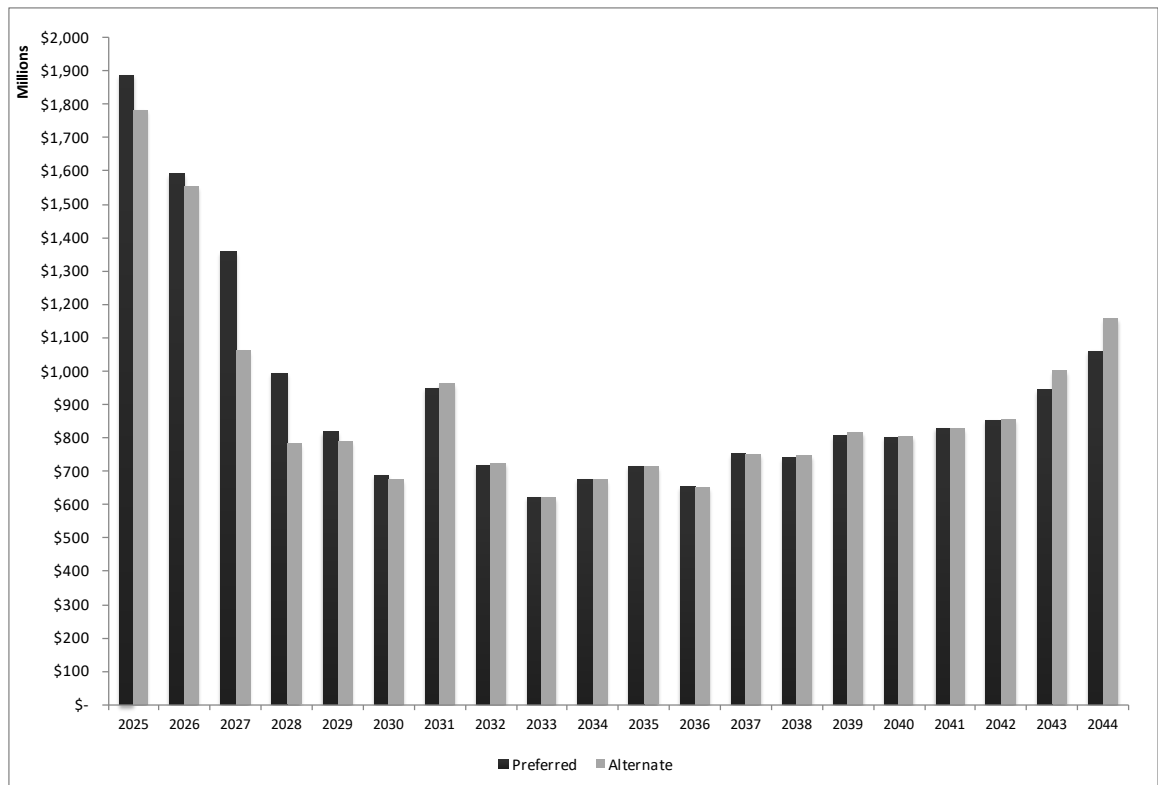


FIGURE BEHRENS-DIRECT-2
SIERRA
CAPITAL EXPENDITURES (\$ - MILLIONS)



III. FINANCIAL IMPACTS TO SIERRA AND NEVADA POWER

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

A. For both utilities, the Preferred and Alternate plans will require funding through a combination of equity and debt over this plan period. The Companies will need to operate the business at a higher equity ratio, especially during the large capital build phases, to maintain credit metrics. After the near-term capital build phase, the Companies plan to bring the equity ratio down to levels that would allow for the Companies to stay at or above the 18 percent funds from operations (“FFO”) to debt ratio required to maintain a Baa1 credit rating. This is currently the credit rating for Nevada Power but Sierra was recently downgraded, as explain in **Exhibit**

Behrens-Direct-2. It is the Companies' intent to operate Sierra to return to a long-term 18 percent FFO/debt ratio in order to get an upgrade as soon as feasible.

Common equity funding will come through internally generated funds, the curtailment of dividends and equity infusions from the parent company as needed. The Companies will, however, have a continued need to access external debt financing to fund the capital projects and to refinance maturing debt. Figures FP-3 and FP-4 in the Financial Plan show annual total external financing over the forecast horizon for the Preferred and Alternate plans for Nevada Power and Sierra, respectively. The external financing projections shown in these two figures reflect both incremental financing requirements for the Companies' projected total capital spending and the refinancing of debt maturities.

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

A. Yes. Both utilities have demonstrated the ability to successfully access the debt markets at competitive rates relative to industry peers with similar credit ratings and to receive additional common equity investments from their parent company NV Energy, Inc. However, maintaining access to external capital at favorable rates is critical to minimize impacts to customer rates. The Companies' ability to continue to attract common equity capital will be dependent on the shareholder having an opportunity to earn a fair return on invested equity capital. Nevada Power currently has issuer credit ratings of 'Baa1' and 'A' and senior secured ratings of 'A2' and 'A+' from Moody's Investors Service, Inc. ('Moody's') and Standard & Poor's Ratings Group, ("Standard & Poor's"), respectively. Sierra currently has

1 issuer credit ratings of ‘Baa2’ and ‘A’ and senior secured ratings of ‘A3’ and ‘A+’
2 from Moody’s and Standard & Poor’s, respectively.
3

4 **14. Q. HAS SIERRA’S CREDIT RATING RECENTLY CHANGED?**

5 A. Yes. In May 2024, Moody’s downgraded Sierra from Baa1 to Baa2 and senior
6 secured rating of A3 from A2. See **Exhibit Behrens-Direct-2** for more details.
7

8 **15. Q. WHAT WAS ONE OF THE MAIN DRIVERS MOODY’S MENTIONED IN**
9 **THE DOWNGRADE REPORT?**

10 A. Moody’s stated that one driver of the downgrade was the Commission’s approval
11 of the Sierra Solar project without any additional regulatory support of its cash
12 flows during the construction phase. Sierra is currently evaluating options to make
13 sure it can secure a credit upgrade as soon as possible. To upgrade, Sierra needs to
14 generate more cash. One option to achieve this is through CWIP in rate base, and
15 the Companies are requesting this accounting treatment for the Greenlink projects
16 in this filing. Section III below provides more details on this request.
17

18 **16. Q. PLEASE ADDRESS THE FINANCIAL ASSUMPTIONS USED FOR THE**
19 **FINANCIAL PROJECTIONS IN THIS FILING.**

20 A. Key financial assumptions are detailed in Section F of the Financial Plan; however,
21 I will highlight a few of the assumptions. The Companies’ financial forecast
22 assumes:

- 23 1) For the purposes of calculating a revenue requirement, a regulatory capital
24 structure for Sierra will be a non-imputed equity ratio in line with its recent
25 Sierra general rate case of 55.19 percent common equity ratio for 2025,
26 2026 and 2027 and be adjusted at each Sierra general rate case thereafter to
27

the actual equity level, which is an average of 52.3 percent over the period of 2028 to 2044.

- 2) For Nevada Power, the common equity ratio as approved in its last approved general rate case of 52.7 percent. The Financial Plan assumes Nevada Power will file its next rate case in 2025 for rate effective 2026 and it will achieve its actual equity ratio of approximately 55 percent and then its actual equity ratio as calculated for each of it following assumed general rate cases. The average equity ratio for Nevada Power from 2028 to 2044 is 54.4 percent.
- 3) Currently approved 9.5 percent allowed return on equity for purposes of calculating Sierra's and Nevada Power's revenue requirements over the forecast period (this does not reflect the need for higher return on equities that might be filed for currently or in the future; this was used as a conservative view on what is approved today).
- 4) In general, a general rate case filing will occur in most years by either Sierra or Nevada Power, which was determined by evaluating when and where major projects will be going in service, with also making sure each company files at least once every three years.
- 5) Current interest rate projections that are in line with today's market which yields higher borrowing costs.
- 6) Obtaining a natural disaster protection plan recovery strategy that transitions to a real-time recovery, such as an approved budget for each year embedded in rates with a balancing account and the ability to catch-up on recovery of the current regulatory asset.

It is important to prepare and present financial forecasts that reflect these assumptions for purposes of understanding the impact of these financial outcomes.

Mr. Sarda is sponsoring the financial forecast modeling utilized in this filing.

17. Q. PLEASE ELABORATE ON THE FINANCIAL IMPACTS USING THESE ASSUMPTIONS.

A. The capital projects proposed in this filing, as well as approved projects from prior filings, may create some temporary pressures on the Companies' credit metrics and credit ratings. **Figures Behrens-Direct-3** and **Behrens-Direct-4** below provide the forecasted credit metrics as calculated by Moody's that are based on cash from operations pre-working capital to debt ratio credit metrics for Nevada Power and Sierra, respectively, which are reflective of using the assumptions listed above and the capital associated with the corresponding plans. These figures illustrate some lower credit metrics during the early years of higher capital expenditure costs and also issuing more debt at Sierra to step down its equity ratio. The Companies will work to support favorable credit metrics above the recommended threshold of 18 percent, however, additional favorable regulatory treatment to ensure financial strength is crucial to provide appropriate financial support during this build phase to return to or maintain above the 18 percent threshold. In addition to the items mentioned above, the Companies will seek more favorable regulatory treatments. These favorable treatments may include critical facility designation, as requested in this case for the Greenlink West and Common Ties projects (already approved for Greenlink North), approval of the actual equity ratios and higher returns on equity ("ROEs") in general rate cases during these large projects construction periods. These requests are imperative to provide appropriate financial regulatory support to help avoid any further credit downgrades and ensure Sierra is upgraded back to Baa1 in the near future by ensuring it can consistently operate at or above the 18 percent FFO to debt credit metric ratio.

**(REDACTED) FIGURE BEHRENS-DIRECT-3
NEVADA POWER
CREDIT METRICS**



**(REDACTED) FIGURE BEHRENS-DIRECT-4
SIERRA
CREDIT METRICS**



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

18. Q. IS THE CREDIT DISCUSSION ABOVE A REASON TO REJECT ANY OF
THE PROJECTS PRESENTED?

A. No, in fact, these credit challenges support the approval request, as demonstrated by the continued improvement in Sierra's credit metric in **Figure Behrens-Direct-4**. The figure shows continued improvement in the credit metrics over time for both the Preferred and Alternate Plans. The proposed projects should be approved for a variety of operational reasons, including resource adequacy, the Companies' obligation to serve, and reliability, as addressed by other witnesses. However, the Commission should also evaluate the projects based on the helpful economics of these projects. Though my testimony and the Financial Plan demonstrate financial stability and strength as well as a plan to afford the necessary investments, additional regulatory support is critical. It is important to note that the Companies have demonstrated in the modeling the ability to take on more debt, curtail dividends or obtain equity infusions, while also stabilizing their equity ratios and still maintaining reasonable credit metrics with reasonable regulatory assumptions to be able to execute on the operational needs requested in this filing. CWIP in rate base incentive is necessary to ensure continued financial strength and helps prevent any future downgrade that could happen if there is an unforeseen financial event. It is good business practice to be prepared in the event of adversity, versus reacting when it might be too late.

CRITICAL FACILITY DESIGNATION

19. Q. WHAT IS A "CRITICAL FACILITY"?

A. NAC 704.9484 describes a "critical facility" as a facility that meets any one or a combination of the following criteria:

- Protects reliability;

- Promotes diversity of supply and demand side resources;
- Develops renewable energy resources;
- Fulfills statutory mandates; and/or
- Promotes retail price stability.

20. Q. HAVE THE GREENLINK PROJECTS BEEN APPROVED AS CRITICAL FACILITIES IN PRIOR FILINGS?

A. Partially. The Greenlink West project was approved in Docket No. 20-07023 but was not granted critical facility designation. The Commission has already designated Greenlink North and the Harry Allen to Northwest 525 kV project as critical facilities.¹ The Companies are requesting critical facility designation for Greenlink West and the Common Ties so that there is consistent treatment on the overall project and the Companies can utilize these incentives to support the Companies' financial strength. Testimony of the Companies' witness Charles Pottey provides further support for the Greenlink West and affiliated projects critical facility designation.

21. Q. WHAT INCENTIVES ARE AVAILABLE FOR "CRITICAL FACILITIES" UNDER THE REGULATIONS?

A. Subsection 3 of NAC 704.9484 discusses incentives and states that the incentives may include, without limitation:

- (a) Earning an enhanced return on equity on the designated critical facility over the life of the facility;
- (b) The inclusion in the rates of construction work in progress (CWIP) associated with the designated facility; and

¹ Docket No. 21-06001, November 26, 2022, Order at 9-10.

(c) Designating costs incurred to construct the designated critical facility as a regulatory asset eligible for recovery under NAC 704.9523.

22. Q. WHAT INCENTIVES ARE THE COMPANIES REQUESTING?

A. The Companies request the CWIP in rate base incentive as well as a simplified version of regulatory asset treatment for the cost recovery mechanism for Greenlink West, North and Common ties. If authorized by the Commission, the Companies would:

- Include the CWIP balances from the Greenlink projects in rate base for general rate cases (or any other recovery mechanism or filing that would allow the Companies to update the CWIP balance in rate base, which may or may not be in place today, such as a capital recovery mechanism that the Companies are continuing to evaluate and may file in the future) prior to the projects being placed into service; and
- Include the Greenlink depreciation expense after the in-service date and until included in rates, in a regulatory asset with no carry charges. The depreciation expense represents the recovery of the Companies costs to construct the project and to receive recovery of all its costs to construct. The Greenlink projects are different than most other projects because of the significant cost to construct. In addition, Nevada Power and Sierra's inability to file a rate case at the same time creates additional regulatory lag and barriers to cost recovery given the fact the project costs are split between the two Companies (70 percent to Nevada Power and 30 percent to Sierra). One company can file a general rate case to try to decrease the lag, but the other company will have to wait almost another year before being able to file a general rate case to start recovering the same expenditures. This can create

at least two years of depreciation expense, the recovery of the asset, that the Companies will not recover without this incentive being approved.

23. Q. HOW DOES THE COMPANIES' REQUEST FOR CRITICAL FACILITY DESIGNATION COMPARE TO THE CRITICAL FACILITY TREATMENTS PREVIOUSLY GRANTED BY THE COMMISSION?

A. Similar requests have been granted in past cases. In Docket No. 04-6030, Nevada Power was granted a two percent incentive return above Nevada Power's authorized ROE for costs associated with construction of the Lenzie Facility (Moapa Energy Facility) and CWIP with a carrying charge.² Lenzie was also allowed regulatory asset treatment for depreciation and carrying charges associated with the project's investment.³

In Docket No. 05-8004, the Commission granted Sierra 1.5 percent ROE adder for Tracy 514 MW combined cycle plant and allowed inclusion of CWIP balances in rate base.⁴

In this case, the Companies request only the inclusion of CWIP in rate base, which benefits customers as shown in Chris Sarda's testimony, and regulatory asset treatment similar to the incentives authorized by the Commission in the Lenzie and Tracy Dockets. The Companies are not requesting an ROE adder.

24. Q. WHY HAVE THE COMPANIES REQUESTED CWIP IN RATE BASE FOR THE GREENLINK PROJECTS AND REGULATORY ASSET TREATMENT?

² September 21, 2004, Order at 22-23.

³ *Id.*

⁴ December 14, 2005, Order at 53-54.

A. The primary purpose for requesting these recovery mechanisms is to generate more cash flow during the construction phase to support credit metrics. As stated in Moody's report where Sierra was downgraded, see **Exhibit Behrens-Direct-2**, Sierra was downgraded in part because it did not receive regulatory support during the Sierra Solar's construction phase as needed to support credit metrics. In evaluating incentive approaches, several key factors were considered, including:

- Effect of an incentive on customer rates over time;
- Timing of general rate case filings and decisions as compared to anticipated pattern of the construction expenditures;
- Effect of an incentive on key financial statistics that are monitored by credit rating agencies such as Moody's and Standard & Poor's; and
- How an incentive is likely to be viewed by the investment community.

The Greenlink projects involve significant construction expenditures and, without CWIP in rate base or favorable cost recovery until the project is in rate base, these projects will put additional pressure on the Companies' credit metrics. These large expenditures without contemporaneous cost recovery can negatively impact the Companies' financial condition, especially as other events can unexpectedly put additional financial pressures on the Companies. For example, since the Companies are subject to seasonal weather conditions, something as simple as a year or two of mild weather, can add significant pressure to the Companies' cash flows and impact credit metrics. Sierra has already been downgraded, and it is critical to ensure Nevada Power does not follow suit, or that Sierra does not get downgraded further. CWIP in rate base treatment has traditionally been a solution for this circumstance.

In the past, the Commission has allowed a utility to place CWIP into rate base because significant construction costs may be detrimental

to the utility's financial situation. CWIP in rate base aids in offsetting the negative effects of regulatory lag by increasing the utility's cash flow and mitigating the impact of the financial requirements of the 514 MW [Tracy unit] addition. CWIP in rate base will also mitigate the impact of the 514 MW on the company's credit rating.⁵

In addition, while CWIP in rate base will flow through rates sooner than regulatory asset treatment, it will moderate the impact on customer rates and support the Companies' liquidity and credit metrics by allowing for cash to be collected early on during the project build phase. CWIP in rate base would also have AFUDC shut off for the CWIP portion in rates and allow the Companies to begin recovery and keep the asset value down which, in the long run, saves customers money from a lower rate base. The Companies' witness Chris Sarda provides the supporting calculations in his testimony.

Including CWIP in rate base is another avenue to help smooth the transition of these costs into rates and avoid rate shock. A first level of return gets layered in during the construction phase and then, when the project is in service, the recovery of the asset is then layered into rates which helps avoid any rate shock.

25. Q. WILL NEVADA POWER AND SIERRA'S CUSTOMERS BENEFIT FROM A FINDING THAT THIS PROJECT IS "CRITICAL" AND ELIGIBLE FOR ENHANCED COST RECOVERY?

A. Yes. The cost of the enhanced ratemaking treatment is minimal when compared to the reliability improvements, increased renewable development, and the long-term benefits that the customers will gain by improved system reliability and reduced exposure to price volatility. In addition, investor reaction to a Commission

⁵ See, e.g., Docket No. 05-8004, December 14, 2005, Order at 53.

endorsement of this type of ratemaking treatment will continue to improve the Companies' long-term financial outlook.

26. Q. HAVE THE COMPANIES CREATED A CWIP IN RATE BASE MODEL TO DEMONSTRATE THE BENEFIT TO CUSTOMERS OVER THE LIFE OF THE PROJECT?

A. Yes. The Companies created a model that demonstrates that over the life of the Greenlink projects, CWIP in rate base is a benefit to customers. However, since the model does not include higher interest costs if the Companies were to be downgraded from their current ratings, there could be even more benefits beyond those modeled in this case. The analysis was modeled to show that even in the current conditions, there is a benefit to customers. Please refer to the testimony of Mr. Sarda for more details on the CWIP in rate base model.

27. Q. IN THE FIFTH AMENDMENT TO THE 2021 JOINT IRP, BCP ARGUED THAT CWIP IN RATE BASE TRANSFERS THE RISK FROM THE COMPANIES TO THE CUSTOMER. DO YOU AGREE?

A. No. It is still the Companies' responsibility to prudently incur costs while the project is being built, with or without CWIP, and the Commission reviews projects for prudence, with or without CWIP. If the Commission was to find anything imprudent, it would be able to issue an order to adjust recovery as needed in the future to prevent recovery of imprudently incurred costs when the Companies bring the project forward to be included in rates. That CWIP is allowed does not change this review and, therefore, the risk does not shift to the customers.

28. Q. HAVE THE COMPANIES BEEN GRANTED APPROVAL FOR CWIP IN RATE BASE AT THE FERC JURISDICTION?

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

A. Yes. It was approved in FERC Docket No. EL22-73.

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

A. Yes.

EXHIBIT BEHRENS-DIRECT-1

MIKE BEHRENS, CPA
VICE PRESIDENT & CHIEF FINANCIAL OFFICER
NV Energy, Inc.
6100 Neil Road
Reno, NV 89511

Mr. Behrens has been the Vice President & Chief Financial Officer of NV Energy, Inc. (“NVE”), since January 2023. He was Controller of NVE from May 2019 to March 2023. Including his time at NVE, he has over 15 years of experience in accounting and finance of which 8 years were in the regulated energy industry. Mr. Behrens has extensive knowledge of the application of Generally Accepted Accounting Principles and Federal Energy Regulatory Commission (“FERC”) accounting compliance. Mr. Behrens has prepared and/or directed the preparation of various reports, analyses, and financial statements submitted to state jurisdictions, FERC and the Securities and Exchange Commission (“SEC”). Mr. Behrens directly testified in various regulatory proceedings and has assisted in supporting testimony and data requests in a number of prior filings before the Public Utilities Commission of Nevada.

Employment History

NV Energy, Inc.

January 2023 to present

Vice President & Chief Financial Officer

(Interim Chief Financial Officer January 2023 to March 2023)

Responsibilities include leadership and oversight of the accounting, tax, financial planning, internal audit, treasury, credit, and risk related functions. With input from other members of NVE’s leadership team, I direct the Company’s financial policies, including its financing activities and capital structure strategies.

May 2019 to March 2023

Controller

Responsible for the general accounting functions, maintenance of the accounting books and records, regulatory accounting compliance and managing the implementation of accounting guidance related to regulatory issues. Responsibilities include compliance with the FERC Uniform System of Accounts, the SEC requirements and the requirements of other federal and state regulatory agencies.

Berkshire Hathaway Energy

June 2017 to May 2019

Manager of Accounting Policy and Special Projects

NV Energy, Inc.

May 2014 to June 2017

Manager of External Financial Reporting

Conagra Brands, Inc.

July 2013 to May 2014

Senior Financial Analyst – Internal Audit

Ernst & Young

September 2007 to June 2013

Audit Manager

September 2012 to June 2013

Audit Senior/Staff

September 2007 to September 2012

Education

University of Iowa, Iowa City, IA

Bachelor of Science in Business, Accounting & Finance Majors, May 2007

Certification

Iowa Certified Public Accountant, issued 2009, active status

EXHIBIT BEHRENS-DIRECT-2

CONFIDENTIAL
FILED UNDER SEAL

AFFIRMATION

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

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

Date: May 31, 2024


MICHAEL BEHRENS

CHRISTOPHER SARDA

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

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

Prepared Direct Testimony of

Christopher Sarda

**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 Planning & Analysis Capital Support Services Director for Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, the “Companies”). My business address is 6226 West Sahara Avenue in Las Vegas, Nevada. I am testifying on behalf of the Companies.

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

A. I have been employed by the Companies since April 2021. My prior experience includes various financial and operational analysis roles across various industries. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Sarda-Direct-1**.

**3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES IN YOUR CURRENT
ROLE.**

1 A. My responsibilities include forecasting and long-range planning, scenario and
2 sensitivity analysis for the Companies. I am responsible for ensuring the accuracy
3 of financial reporting and financial plans including integration with regulatory
4 models and maintaining the integrity of internal controls for the Companies. I
5 provide modeling support for the development of the Companies' long-range
6 financial planning models, including the 10-year plan.
7

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

9 A. Yes. Most recently, I testified before the Commission in the Nevada Power general
10 rate case, (Docket No. 23-06007).
11

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

14 A. I am sponsoring the financial forecast modeling and analysis used to support the
15 Financial Plan. The financial analysis was performed using the Companies'
16 financial forecasting model based on the Utilities International, Inc. ("UI"),
17 platform. Access to the model, calculations, and outputs are available for review at
18 the Companies' offices subject to a confidentiality agreement. In addition, I sponsor
19 the customer rate impact analysis appended to the Financial Plan and the analysis
20 for the construction work in process ("CWIP") in rate base incentive.
21

22 **6. Q. WHAT EXHIBITS ARE YOU SPONSORING?**

23 A. My statement of qualifications is attached as **Exhibit Sarda-Direct-1**.
24
25
26
27

7. **Q. PLEASE DESCRIBE THE FINANCIAL ANALYSIS PERFORMED.**

A. As has been the case in previous integrated resource plan filings, the financial model was used to estimate the forward-looking financial impacts of the Companies' Preferred and Alternate plans holistically, as incremental to the Companies' other financing plans and assumptions, to provide a more robust picture of the Companies' financial position including the proposed alternatives. The capital expenditures included for the Preferred and Alternate plans were constructed using the capital expense recovery ("CER") model. For Nevada Power, the total incremental capital expenditures requested in this filing occur in years 2025 through 2028 and are estimated to be \$1.1 billion, in the Preferred and Alternate Plans. For Sierra, the total incremental capital expenditures requested in this filing occur in years 2025 through 2031 and are estimated to be \$1.8 billion and \$1.3 billion for the Preferred and Alternate Plans, respectively.

8. **Q. A CUSTOMER RATE IMPACT ANALYSIS SECTION IS INCLUDED TO THE FINANCIAL PLAN NARRATIVE. WOULD YOU PLEASE DESCRIBE THIS SECTION?**

A. The Companies took a different approach to calculating the customer rate impact analysis for this filing. The Companies calculated the incremental base tariff general rate ("BTGR") and Base Tariff Energy Rate ("BTER") for four resource planning outputs: Preferred, Alternate, Low Carbon, and No Open Position plans, as calculated in the capital expense reports used in the economic analysis. Each of these outputs were compared to the Base Case resource plan that does not include any of the proposed projects. The Companies employed this method to expand the calculations and create a more holistic view of the rate impact of the alternative

resource options. Previous analysis only reflected BTGR costs and, thus, did not account for the power purchases and fuel purchases impacts.

9. **Q. PLEASE EXPLAIN THE MODELING THAT SUPPORTS THE COMPANIES' REQUEST FOR THE CWIP IN RATE BASE INCENTIVE.**

A. I was responsible for the representative modeling that supports the Companies' request for CWIP in rate base for the Greenlink project. The inputs to this model include available yearly budgets for Greenlink West, Greenlink North, and Greenlink Common Ties. The model compares the current accepted allowance for funds used during construction ("AFUDC") calculation against a scenario where the Companies receive the CWIP in rate base incentive annually. When the CWIP balance is included in rates, AFUDC compounding turns off. This results in the Companies receiving a return component earlier to support credit quality during the construction phase. The benefit to the customers of this return coming in earlier is a lower plant in service amount into rates over the life of the project. The model then compares a present worth rate of return to reflect the top down difference in costs to customers between the CWIP approach and the AFUDC approach. The model used 7.43 percent and 6.95 percent approved weighted average cost of capital ("WACC") for NPC and SPPC as discount rates throughout the analysis.

10. **Q. WHAT ARE THE MAJOR ASSUMPTIONS AND OUTCOMES FROM THE CWIP INCENTIVE ANALYSIS?**

A. As Sarda Table-1 below demonstrates, the analysis shows an average per year CWIP Return incentive of \$77 million for Nevada Power (ranges from \$57.7 million to \$106.8 million) and an average \$60 million a year CWIP Return incentive for Sierra (ranges from \$23.1 million to \$98.7 million) across the Greenlink projects in years 2026-2028. The total cost to customers across the life

of the projects is represented by the Present Worth of the Revenue Requirement ("PWRR"). The PWRR number includes the CWIP incentive return that begins in 2026.

For Nevada Power, the standard AFUDC approach yields a \$2.408 billion PWRR, while the CWIP approach produces a lower \$2.391 billion PWRR. Thus, the analysis shows \$16.2 million in savings in present value terms for Nevada Power customers under with CWIP. For Sierra, the analysis shows a \$2.7 million savings in present value terms under the CWIP approach. That is the difference between a \$1.999 billion PWRR with the AFUDC against a \$1.996 billion PWRR under the CWIP approach.

SARDA TABLE -1

CWIP IN RATE BASE MODELING SUMMARY

NPC Standard AFUDC Total			
Year	Cash Flow	AFUDC	CWIP Return
2024	311,495	22,524	-
2025	534,196	44,663	-
2026	505,155	86,593	-
2027	724,233	138,699	-
2028	302,956	71,043	-
2029	-	-	-
2030	-	-	-
Present Worth Rev Req		2,407,596	

NPC CIRB Totals			
Year	Cash Flow	AFUDC	CWIP Return
2024	311,495	22,524	-
2025	534,196	44,663	-
2026	505,155	18,767	67,827
2027	724,233	26,905	106,754
2028	302,956	11,255	57,745
2029	-	-	-
2030	-	-	-
Present Worth Rev Req		2,391,349	

SPPC Standard AFUDC Total			
Year	Cash Flow	AFUDC	CWIP Return
2024	277,477	17,426	-
2025	522,217	38,643	-
2026	534,406	78,046	-
2027	396,613	115,823	-
2028	129,838	28,353	-
2029	-	-	-
2030	-	-	-
Present Worth Rev Req		1,999,515	

SPPC CIRB Totals			
Year	Cash Flow	AFUDC	CWIP Return
2024	277,477	17,426	-
2025	522,217	38,643	-
2026	534,406	29,618	59,476
2027	396,613	16,779	98,675
2028	129,838	4,512	23,080
2029	-	-	-
2030	-	-	-
Present Worth Rev Req		1,996,793	

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

A. Yes, it does.

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, Director Capital Services

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: May 31, 2024


CHRISTOPHER SARDA

JANET WELLS

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

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

Prepared Direct Testimony of

Janet Wells

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

A. My name is Janet Wells. My current position is Vice President of Regulatory 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 primary business address is 6100 Neil Road, Reno, Nevada. I am filing testimony on behalf of the Companies.

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

A. I hold a Bachelor of Arts Degree in Geography and a Master of Science Degree in Applied Economics and Statistics. I have more than 15 years of utility experience within the Rates and Regulatory Affairs department. Prior to joining the Companies, and during an absence from the Companies, I worked in economic consulting and research. The details of my background and experience are provided in **Exhibit Wells-Direct-1.**

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

3 A. As Vice President of Regulatory, my responsibilities include overseeing the
4 preparation of regulatory filings before the Public Utilities Commission of Nevada
5 (“Commission”), and specifically, the work performed by the Load Research and
6 Forecasting, Pricing, and Regulatory Affairs technical teams.
7

8 4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY
9 WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA
10 (“COMMISSION”)?

11 A. Yes, most recently in Docket Nos. 24-05022 and 24-05023, the Companies Clean
12 Transition Tariff Advice Letter Applications. **Exhibit Wells-Direct-1** provides a
13 full list of proceedings in which I have testified before the Commission.
14

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

16 A. The purpose of my testimony is to provide support for the Companies’ exemplar
17 base pricing model framework (the “Model”) for the Large Customer Market Price
18 Energy Tariff, Schedule No. LCMPE (“LCMPE”) in compliance with directives 5
19 and 6 on page 40 of the Commission Order dated November 1, 2023, in Docket
20 Nos. 23-02010 and 23-02011. In addition, I support the presentation of anticipated
21 Energy Supply Agreements (“ESA”) to be filed concurrently with the Joint
22 Integrated Resource Plan (“IRP”).
23

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

25 A. Yes. I am sponsoring the following Exhibits:

26 Exhibit Wells-Direct-1 Statement of Qualifications
27

28 Wells-DIRECT

Exhibit Wells-Direct-2 ESA Exemplar Pricing Model for Nevada Power
Exhibit Wells-Direct-3 ESA Exemplar Pricing Model for Sierra

7. Q. PLEASE DESCRIBE THE PRICING MODEL INCLUDING ANY UPDATES.

A. The Models presented build upon those that were filed in Docket Nos. 23-02010 and 23-02011. In general, the Models begin with an hourly load profile and resource information. The Companies used a representative large customer rate class for the hourly load profile and the general characteristics of the most recently approved solar and battery resource as exemplars. The Models continue to provide the calculation of the ESA rate, including rate components that apply in all hours but are collected through the ESA rate such as planning reserve margin. The Models also include other rate components applicable outside of resource hours such as the base tariff energy rate and deferred energy accounting adjustment. The Models provide both the ESA rate and the resulting overall fully bundled effective rate and compares that to the customer's otherwise applicable rate class. While the Models show the comparison to the otherwise applicable rate class for transparency, at the time of filing an ESA, the Companies will provide the applicable comparison of the ESA rate to the distribution-only rate, the most appropriate otherwise applicable rate class for an eligible LCMPE customer.

The updates to the Models include replacing the one-year representative capacity portion of the long term avoided cost ("LTAC") with a 25-year average of the forecasted LTAC to represent the forecasted rates over the term of the ESA. This average capacity price is added to any hour that the load is not being served by the resource.

The Companies also removed the shorter term ESA model that provided pricing based on a time frame that was shorter than the life of the resource. While that option remains available for customers, it would be built out of the same foundation as provided in the Models with the addition of a forward price protection if a shorter term is requested. The Companies have thus far not received much interest from customers for a shorter term, rather more often the request is in alignment with the life of the resource.

For illustrative purposes, the Models show overall effective rates using both the most recent base tariff energy rate ("BTER") and deferred energy accounting adjustment ("DEAA") rate as well as the forecasted rate for the next quarter to show how the pricing changes with that input.

8. Q. HAVE THE COMPANIES FILED ADVICE LETTERS REQUESTING APPROVAL OF AN ADDITIONAL TARIFF THAT EMPLOYS AN ESA?

A. Yes. On May 21, 2024, the Companies filed a request for Commission approval of the proposed Clean Transition Tariff ("CTT"). An ESA under the CTT begins with the same Models as are presented here for the LCMPE. The CTT is applicable for existing fully bundled customers and therefore requires a different rate comparison because the otherwise applicable class is the fully bundled rate.

9. Q. DO THE COMPANIES ANTICIPATE FILING ANY ESA APPLICATIONS CONTEMPORANEOUS WITH THIS IRP?

A. Yes. The Companies anticipate filing three ESAs in partnership with Callisto Enterprises LLC (a subsidiary of Google), Coeur Rochester Inc., and the Las Vegas Convention and Visitor's Authority. All ESAs are filed pursuant to the pending

CTT Advice Letter filings and are contingent upon approval of the CTT. The ESA with Callisto Enterprises LLC is supported entirely by a dedicated geothermal resource and uses the entire output of that PPA. The remaining ESAs use a weighted average of the three solar and battery purchased power agreements (“PPAs”) requested for approval. Each application will be filed contemporaneous with or shortly after the IRP has been filed, using the Models provided here with updates to include necessary pricing adjustments to reflect the CTT. Each application will reflect the resource used to develop the pricing and reflect the customer specific hourly loads. Finally, each application will include the customer specific ESA contract.

10. **Q. ARE THE COMPANIES REQUESTING APPROVAL OF THE LCMPE MODELS PROVIDED WITH THIS FILING?**

A. Yes. The Companies request the Commission approve the Models as filed for use as a baseline in future ESAs filed under the LCMPE tariff.

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

A. Yes.

EXHIBIT WELLS-DIRECT-1

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

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

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

Employment History

NV Energy

October 2011 to Present

December 2000 to August 2005

Vice President of Regulatory

May 2022 to Present

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

Regulatory Policy Director, Rates and Regulatory Affairs

March 2020 to April 2022

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

Manager, Load Research, Rates and Regulatory Affairs

April 2017 to February 2020

Supervisor, Load Research, Rates and Regulatory Affairs

July 2012 to March 2017

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

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

Senior Economist, Advanced Service Delivery Project

October 2011 to July 2012

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

Staff Economist, Rates and Regulatory Affairs

October 2001 to August 2005

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

Senior Economist, Rates and Regulatory Affairs

December 2000 to October 2001

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

Other Related Employment

University of Nevada, Reno

May 2005 to August 2006

Research Associate

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

Triangle Economic Research, Durham, NC

July 1997 to December 2000

Senior Economist, March 2000-December 2000

Economist, July 1997-March 2000

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

Prior Testimony Before Public Utilities Commissions

PUCN Docket Nos.: 15-07041, 15-07042, 16-06006, 17-06003, 17-06014, 17-06015, 18-08007, 18-10034, 19-02002, 19-04002, 19-06002, 20-06003, 21-09031, 21-09032, 22-06014, 22-09002, 22-09006, 22-11032, 23-02010, 23-02011, 23-06007, 23-08019, 24-02026, 24-02027, 24-05022, and 24-05023.

Education

University of Nevada, Reno

Master of Applied Economics and Statistics, August 1996

University of Manitoba, Winnipeg, Manitoba

Bachelor of Arts in Geography, June 1992

Continuing Education

NERA Marginal Cost Methodology for Electric Utilities

SAS Programming I and II

CORE Leadership Training

Six Sigma Green Belt Certification

EXHIBIT WELLS-DIRECT-2

NEVADA POWER COMPANY - d/b/a NV ENERGY

ESA PRICING MODEL FOR XX

Energy Supply Agreement Pricing Model

Docket No. XX-XXXXX Direct Filing

PREPARED BY THE

REGULATORY PRICING AND ECONOMIC ANALYSIS DEPARTMENT

Date

THIS ESA PRICING MODEL WAS PREPARED TO SERVE AS THE
BASIS FOR THE FIXED ENERGY RATE IN DOCKET NO. XX-XXXXX

Table 1: ESA Pricing

Line No.	Cost Components	Costs (\$)	Line No.
1			1
2	PV Cost	\$35,116,730	2
3	Battery Cost	\$28,139,726	3
4	Grid Hour Capacity Cost	\$913,693	4
5	Planning Reserve Margin Cost	\$9,458,969	5
6	Placeholder Forward Price Protection	\$0	6
7	Total Annual Cost	\$73,629,118	7
8			8
9	Forecast Annual Energy (MWh)	881,635	9
10			10
11	Cost Components	Costs (\$/MWh)	11
12	PV Cost	\$39.83	12
13	Battery Cost	\$31.92	13
14	Grid Hour Capacity Cost	\$1.04	14
15	Planning Reserve Margin Cost	\$10.73	15
16	Placeholder Forward Price Protection	\$0.00	16
17	ESA Offer Price >>	\$83.51	17
18			18
19			19
20			20

Table 2: ESA Pricing Cost Components

Line No.		Rate Component Calculation	Costs (\$)	Line No.
1	Component 1 PV Cost	Total PV + BESS (MWh)	924,124	1
2		PV Price (\$/MWh)	\$38.00	2
3		Annual PV + BESS Energy Cost	\$35,116,730	3
4				4
5	Component 2 Battery Cost	Annual Storage Demand (MW)	253,605	5
6		Battery Capacity Price (\$/MW)	\$111	6
7		Annual Storage Capacity Cost	\$28,139,726	7
8				8
9	Component 3 Grid Hour Capacity Cost	Grid Hour Delivered (MWh)	578,083	9
10		Grid Hour Capacity Cost (\$/MWh)	\$1.58	10
11		Annual Grid Hour Capacity Cost	\$913,693	11
12				12
13	Component 4 Planning Reserve Margin	Planning Reserve Margin Energy (MWh)	1,459,717	13
14		Planning Reserve Margin Price (\$/MWh)	\$6.48	14
15		Annual Planning Reserve Margin Cost	\$9,458,969	15
16				16
17	Component 5 Placeholder Forward Price Protection	FPP Energy (MWh)	881,635	17
18		Placeholder Forward Price Protection (\$/MWh)	\$0.00	18
19		Total Placeholder Forward Price Protection	\$0	19
20				20
21		Total Annual Cost	\$73,629,118	21
22				22
23				23
24				24

Table 3: Billing Determinants and Pricing

Line No.			Line No.
1			1
2	Customer Profile	MWh	2
3	Energy Served by Dedicated Resource - Includes Battery Charging w/ Losses	924,124	3
4	Round Trip Battery Charging Losses	-42,490	4
5	Grid Energy (MWh)	578,083	5
6	Planning Reserve Margin Energy	1,459,717	6
7			7
8	BESS Facility Characteristics	MW	8
9	Annual Storage Demand	253,605	9
10			10
11	Pricing		11
12	PV Price (\$/MWh)	\$38.00	12
13	Battery Capacity Price (\$/MW)	\$110.96	13
14	Grid Hour Capacity Cost (\$/MWh)	\$1.58	14
15	Planning Reserve Margin Price (\$/MWh)	\$6.48	15
16	Placeholder Forward Price Protection (\$/MWh)	\$0.00	16
17			17
18	Battery Capacity Price Calculation		18
19	Monthly Battery Capacity Cost (\$/MW-Month)	\$13,500.00	19
20			20
21	Annual Battery Capacity Cost (\$/MW-Year)	\$162,000.00	21
22	Annual Charging Hours (Hours)	1,460	22
23	Hourly Battery Capacity Cost (\$/MW-Hour)	\$110.96	23
24			24

EXHIBIT WELLS-DIRECT-3

SIERRA PACIFIC POWER COMPANY - d/b/a NV ENERGY

ESA PRICING MODEL FOR XX

Energy Supply Agreement Pricing Model

Docket No. XX-XXXXX Direct Filing

PREPARED BY THE

REGULATORY PRICING AND ECONOMIC ANALYSIS DEPARTMENT

Date

THIS ESA PRICING MODEL WAS PREPARED TO SERVE AS THE
BASIS FOR THE FIXED ENERGY RATE IN DOCKET NO. XX-XXXXX

Table 1: ESA Pricing

Line No.	Cost Components	Costs (\$)	Line No.
1			1
2	PV Cost	\$11,348,133	2
3	Battery Cost	\$9,033,798	3
4	Grid Hour Capacity Cost	\$294,064	4
5	Planning Reserve Margin Cost	\$2,422,174	5
6	Placeholder Forward Price Protection	\$0	6
7	Total Annual Cost	\$23,098,168	7
8			8
9	Forecast Annual Energy (MWh)	284,994	9
10			10
11	Cost Components	Costs (\$/MWh)	11
12	PV Cost	\$39.82	12
13	Battery Cost	\$31.70	13
14	Grid Hour Capacity Cost	\$1.03	14
15	Planning Reserve Margin Cost	\$8.50	15
16	Placeholder Forward Price Protection	\$0.00	16
17	ESA Offer Price >>	\$81.05	17
18			18
19			19
20			20

Table 2: ESA Pricing Cost Components

Line No.		Rate Component Calculation	Costs (\$)	Line No.
1	Component 1 PV Cost	Total PV + BESS (MWh)	298,635	1
2		PV Price (\$/MWh)	\$38.00	2
3		Annual PV + BESS Energy Cost	\$11,348,133	3
4				4
5	Component 2 Battery Cost	Annual Storage Demand (MW)	81,416	5
6		Battery Capacity Price (\$/MW)	\$111	6
7		Annual Storage Capacity Cost	\$9,033,798	7
8				8
9	Component 3 Grid Hour Capacity Cost	Grid Energy (MWh)	196,551	9
10		Non-Solar Capacity Price (\$/MWh)	\$1.50	10
11		Annual Non Solar Capacity Cost	\$294,064	11
12				12
13	Component 4 Planning Reserve Margin	Planning Reserve Margin Energy (MWh)	481,545	13
14		Planning Reserve Margin Price (\$/MWh)	\$5.03	14
15		Annual Planning Reserve Margin Cost	\$2,422,174	15
16				16
17	Component 5 Placeholder Forward Price Protection	FPP Energy (MWh)	284,994	17
18		Placeholder Forward Price Protection (\$/MWh)	\$0.00	18
19		Total Placeholder Forward Price Protection	\$0	19
20				20
21		Total Annual Cost	\$23,098,168	21
22				22
23				23
24				24

Table 3: Billing Determinants and Pricing

Line No.			Line No.
1			1
2	Customer Profile	MWh	2
3	Energy Served by Dedicated Resource - Includes Battery Charging w/ Losses	298,635	3
4	Round Trip Battery Charging Losses	-13,641	4
5	Grid Energy (MWh)	196,551	5
6	Planning Reserve Margin Energy	481,545	6
7			7
8	BESS Facility Characteristics	MW	8
9	Annual Storage Demand	81,416	9
10			10
11	Pricing		11
12	PV Price (\$/MWh)	\$38.00	12
13	Battery Capacity Price (\$/MW)	\$110.96	13
14	Non-Solar Capacity Price (\$/MWh)	\$1.50	14
15	Planning Reserve Margin Price (\$/MWh)	\$5.03	15
16	Placeholder Forward Price Protection (\$/MWh)	\$0.00	16
17			17
18	Battery Capacity Price Calculation		18
19	Monthly Battery Capacity Cost (\$/MW-Month)	\$13,500.00	19
20			20
21	Annual Battery Capacity Cost (\$/MW-Year)	\$162,000.00	21
22	Annual Charging Hours (Hours)	1,460	22
23	Hourly Battery Capacity Cost (\$/MW-Hour)	\$110.96	23
24			24

AFFIRMATION

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

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

Date: May 31, 2024


JANET WELLS