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FILED WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA - 5/6/2026

# BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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|---|---|
| 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 2027-2046 integrated resource plan, 2027-2029 Action Plan and 2027-2029 Energy Supply Plan. | Docket No. 26-05___ |

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## SUMMARY


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# SUMMARY

## SECTION I – EXECUTIVE SUMMARY

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 either the "Companies" or "NV Energy") submit this 2026 Joint Integrated Resource Plan (the "2026 Joint IRP").

NV Energy makes this 2026 Joint IRP filing at a pivotal time. According to the North American Electric Reliability Corporation ("NERC"), the industry is "entering a period of load growth unprecedented in recent memory, driven by data centers [(*e.g.*, artificial intelligence and computational load)] that support" daily life and "advance North America's leadership in the deployment of artificial intelligence."[1] Nevada is experiencing this same data-center-driven load growth dynamic.

Nevada—and northern Nevada in particular—is a sought-after location for data centers due to the expanse of developable land, a favorable climate for efficient cooling, and robust fiber connectivity. NV Energy has received approximately 22,000 megawatts ("MW") or 22 gigawatts ("GW") of interest inquiries from data centers and has executed approximately 6 GW of signed Rule 9 agreements (generally consisting of master planned community ("MPC") umbrella agreements, substation high voltage distribution ("SHVD") agreements, and high voltage distribution ("HVD") agreements) to facilitate the transmission, substation, and high voltage distribution infrastructure needed to interconnect these large loads. These agreements do not address generation and electric supply. As

[1] Correspondence from NERC, dated March 20, 2026, to the Federal Energy Regulatory Commission ("FERC") ("NERC March 20, 2026, Letter"). Between 2005 and 2020, U.S. electricity sales were largely stagnated, with U.S. retail electricity sales peaking around 2007, according to the U.S. Energy Information Administration ("EIA") data. The EIA projects material acceleration in electric sales and demand, as to most organized U.S. markets. U.S. Energy Information Administration, *Today in Energy*, "After more than a decade of little change, U.S. electricity consumption is rising again" (May 13, 2025); *see also* U.S. Energy Information Administration, *Annual Energy Outlook 2026* (April 2026) (finding that after approximately 15 years of nearly flat electricity consumption, U.S. electricity demand has accelerated, with average growth of approximately 2.1% per year over the past five years and predicting that growth will continue with data center server energy use as a major factor).

### KEY ELEMENTS OF NV ENERGY'S 2026 INTEGRATED RESOURCE PLAN

The 2026 Joint IRP proposes a planning and service framework for large load customers, which ensures that households, small businesses, and existing commercial and industrial customers are not asked to bear costs driven primarily by new large-load service requests.

The Preferred Plan in the 2026 Joint IRP proposes to add 4,370 megawatts ("MW") of new solar generating projects, 5,405 MW of battery energy storage system ("BESS") projects, 180 MW of geothermal generation projects, and 1,223 MW of peaking turbines, in an integrated approach that reduces stranded-asset risk, supports timely and reliable service to new customers, and protects affordability and reliability for existing customers.

The Preferred Plan also proposes a $238 million three-year energy efficiency and demand reduction budget. The suite of energy efficiency and demand reduction programs improve customer opportunities to reduce energy consumption. Finally, the distributed resources plan proposes non-wires solutions to alleviate grid constraints.

interconnecting load is typically heavily discounted in IRP load forecasts, the Companies must plan prudently for the potential that these loads materialize. This planning is particularly critical given that approximately 84 percent (almost 5 GW) of the signed agreements are with large-load customers in northern Nevada—Sierra's load forecast projects kilowatt-hour ("kWh") sales will double by 2029. Putting it in perspective, Nevada Power's peak load for 2025 was 6,168 MW and Sierra's peak load for 2025 was 2,073 MW.

Projected load growth represents a step-change with unique risks and opportunities. On the risk side of the scale, growth is concentrated in large loads, with individual load interconnection requests commonly in the hundreds of MW. Utilities responding to this step-change in load need to make "significant investment in" generation and transmission infrastructure to meet rapidly evolving energy needs.[2] On the opportunity side of the scale, large load additions have exhibited high load factors. Stated differently, data centers have historically used energy consistently from hour-to-hour, with minimal variation between low-load and high-load hours. This "flatter" load improves system utilization, potentially allowing fixed costs to be spread across more sales.

As NERC notes, responding to large load requests presents new and distinct challenges, requiring utilities like NV Energy to remain laser-focused on reliability, risk and affordability. Recently, large loads have responded to, and amplified, grid instability.[3] If unmanaged, large load additions unquestionably present reliability risks. While NERC's letter focuses on reliability rather than rates, its warning that unprecedented large-load growth requires significant new infrastructure investment implicitly underscores the financial and cost-allocation risks public policy makers, regulators and utilities face if such growth is not planned for deliberately and responsibly. Comparing the investment required for the Base Load Forecast to that required without the large data center load growth,[4] large load additions can be seen to accelerate and increase the need for generation and transmission infrastructure. Without risk mitigation controls, these investments could create upward pressure on rates.

NV Energy responded to these planning challenges through a deliberate, risk-aware planning framework anchored by the Large Load Electric Service Agreements ("LLESA") and a flexibility-focused Preferred Plan. The Companies employ resource planning analysis for both a Base Load Forecast and a reduced Base Minus Load Forecast to isolate the incremental generation and transmission needs—and associated costs—that NV Energy would not incur but for large-load service requests. The LLESA contains several risk mitigation provisions designed to ensure that large load additions pay for the infrastructure needed to meet their service requests. These include

[2] *See* NERC March 20, 2026, Letter, available at https://www.nerc.com/globalassets/who-we-are/legal--regulatory/filings--orders/nerc-filings-to-ferc/2026/nerc_accelerated-ll-action-plan_rm26-4_signed.pdf.

[3] NERC, *Incident Review Considering Simultaneous Voltage-Sensitive Load Reductions* (Jan. 8, 2025), available at https://www.nerc.com/globalassets/ourwork/reports/event-reports/incident_review_large_load_loss.pdf.

[4] *See* Base Minus Informational Case in the Additional Studies and Information subsection of the Economic Analysis Section of the narrative.

customer-specific charges that operate as contributions in aid of construction to reduce the Companies' investment in generation and transmission additions, minimum demand and energy charges, security requirements, and termination payments. This approach, coupled with similar provisions in Rule 9 agreements, provides a transparent, fact-based foundation for aligning cost responsibility with cost causation and ensures that households, small businesses, and existing commercial and industrial customers are not asked to bear costs driven primarily by new large-load service.

In parallel, the Companies' Preferred Plan—Obsidian—reflects a deliberate emphasis on flexibility and executability. NV Energy developed the renewable energy expansion plan, which seeks approval of 23 third-party power purchase agreements ("PPAs") adding approximately 4,550 MW of renewable generation and 5,405 MW of battery energy storage systems ("BESS") output capacity across the Nevada Power and Sierra systems to support Renewable Portfolio Standard ("RPS") compliance, load growth, and reliability needs. The plan was developed through the 2024 All-Source Request for Proposals ("RFP") using selection criteria recalibrated to emphasize deliverability and executability—prioritizing projects with lower federal permitting exposure, stronger tax-credit "safe harbor" positioning, and near-term commercial operation date ("COD") potential—while targeting resources that can help relieve emerging energy and capacity constraints in northern Nevada (including Sierra's import-constrained system).

Likewise, the thermal additions in the Obsidian Plan include 802 MW of aeroderivative peaking turbines (centered around 2030–2031) and 421 MW of frame peaking turbines in the early-2030s, providing fast-start, flexible capacity to support resource adequacy. They were selected because they minimize execution and supply-chain risk—particularly by avoiding heavy reliance on multiple frame combustion turbines with 2031 CODs—while also limiting near-term capital exposure and preserving planning flexibility amid large-load uncertainty. This design directly addresses uncertainty around the timing, magnitude, and geographic concentration of large-load growth, while preserving optionality.

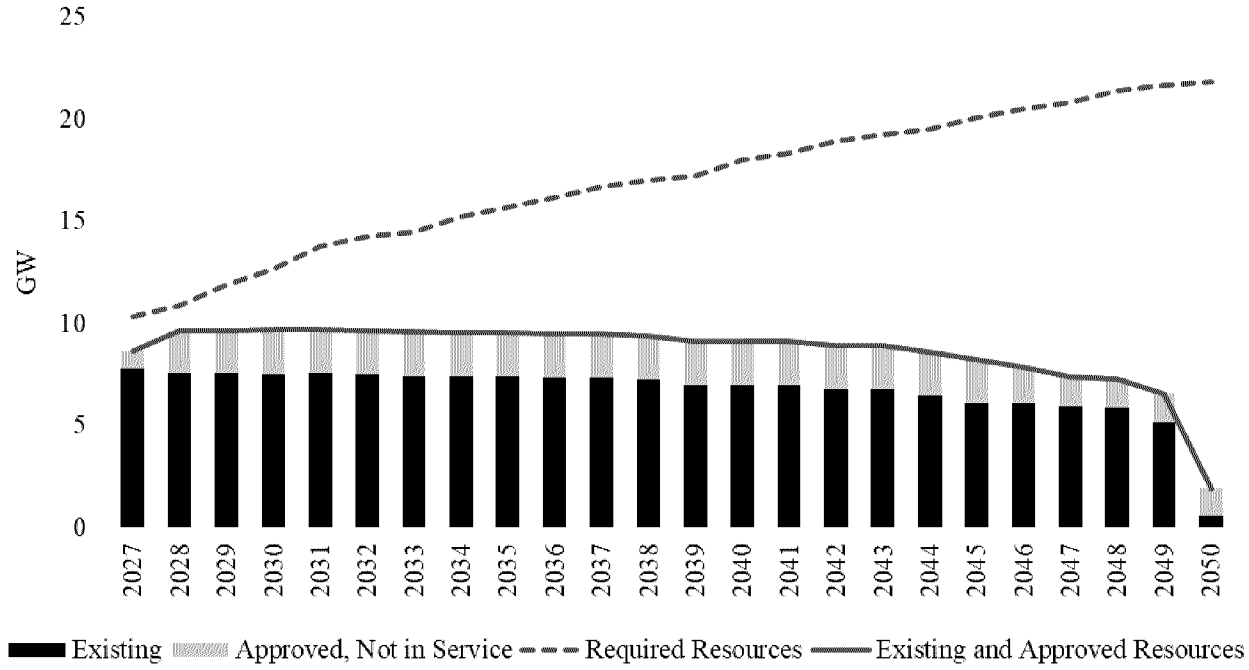
Taken together, the LLESA, the load-scenario framework, and the flexible resource portfolio translate emerging national reliability guidance and empirical load trends into concrete planning and contracting tools. This integrated approach reduces stranded-asset risk, supports timely and reliable service to new customers, and protects affordability and reliability for existing customers as Nevada's future load trajectory takes shape.

In conclusion, NV Energy's policy position is clear: the Companies plan to support data center development in Nevada, but only with prudent guardrails that protect reliability and ensure that costs caused by large-load additions are borne by those loads, not shifted to existing customers. Accordingly, NV Energy's planning and service framework prioritizes deliverable, flexible resources and infrastructure that can be timed and scaled to actual load realization, while

preserving optionality under evolving federal policy, permitting, and supply-chain conditions. The Companies seek approval of the Preferred Plan resources; however, the need for these resources is premised on the Base Load Forecast and the large new loads that underpin it. By expeditiously reviewing and approving the LLESA framework, the Commission will give much needed certainty to the Companies and the development community around the cost responsibility for the new generation and transmission needed to serve the large new loads. This certainty, in turn, would allow the Companies to firm up the load forecast. Consistent with these principles, a primary objective of this 2026 Joint IRP filing is to establish clear, durable planning and service rules to address step-change load growth that are just, reasonable, and in the public interest.

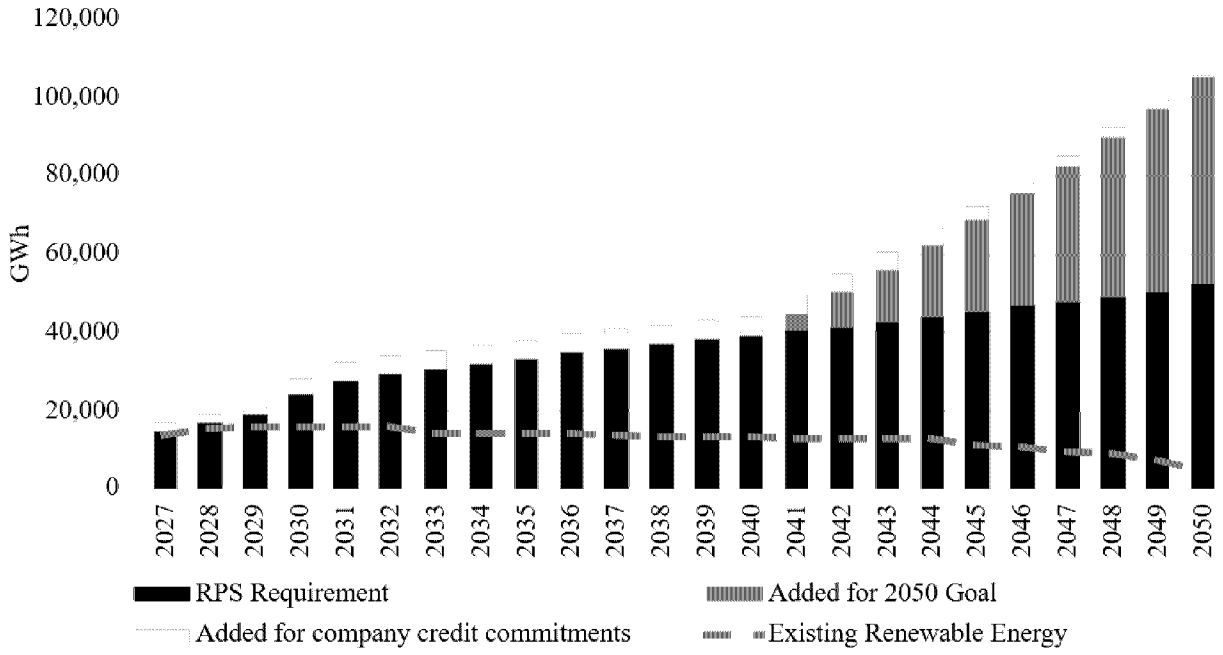
Figure S-1 illustrates the Companies' capacity position—their capacity needs—with the 2026 IRP Base Load Forecast described in Section III, Forecast of Growth. The figure shows the system capacity requirements (loads plus Planning Reserve Margin ("PRM") and reserves for Open Access Transmission Tariff customers) as updated in this 2026 Joint IRP, existing resources (owned resources and those under contract and in service), and resources approved but not yet in service. Thermal units are shown at their peak capacities derated for their historic average forced outage rate while renewable and storage units have been adjusted for their effective load carrying capability, consistent with the use of an unforced capacity PRM as in the 2024 Joint IRP. The difference between the required resources (top dashed line) and the existing and approved resources (solid lower line) represents the total capacity need for NV Energy.

**FIGURE S-1**
**NV ENERGY SYSTEMWIDE CAPACITY POSITION**



The Companies also consider the energy required to serve the growing load, as well as the proportion of this energy that would need to be supplied by renewable resources to meet the combined state RPS mandate and the Companies' credit commitments (NGR, ESA, and 704B obligations). While the Companies do not request even conditional approval of resources in this filing for this purpose, all plans in this filing target the Companies' proportionate share of the state's 2050 clean energy goal. Starting in 2041, the cases and plans in this filing commence a trajectory towards the Companies' proportionate share of the state's 2050 clean energy goal. Figure S-2 offers an approximation of the net renewable energy that the Companies may need in future years and is not as refined as the detailed calculations provided in the Renewables Section of the Supply Plan.

**FIGURE S-2**
**NV ENERGY NEED FOR ADDITIONAL RENEWABLE ENERGY**




## SECTION II – INTRODUCTION TO THE COMPANIES: NAC § 704.9215(2)(a)

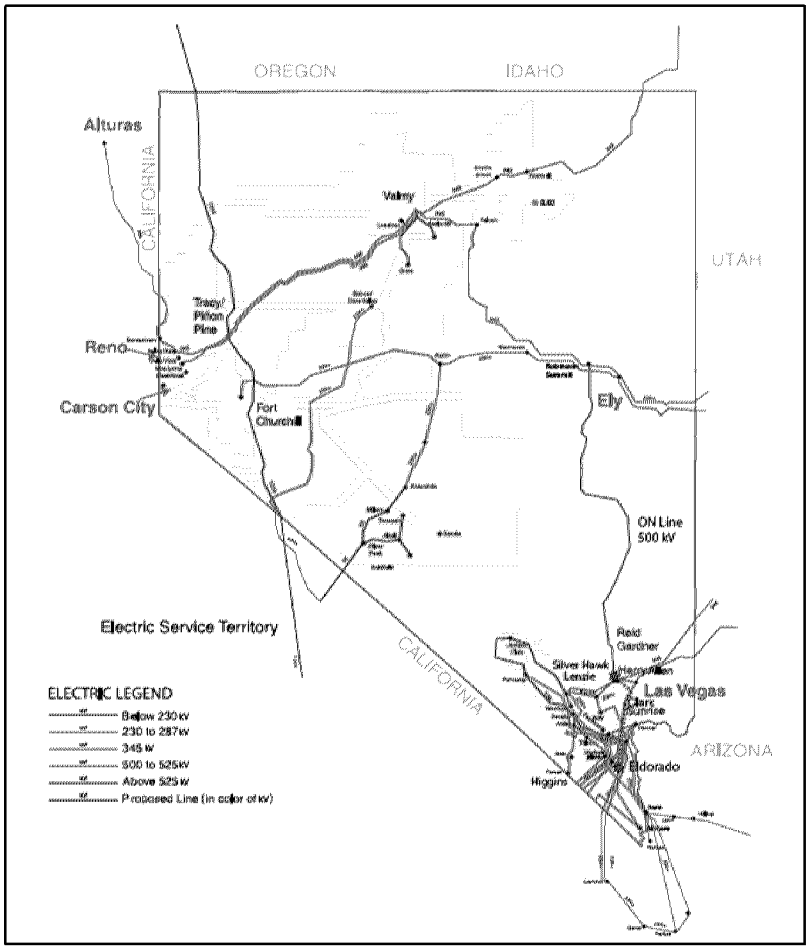
***Nevada Power and Sierra Described.*** Nevada Power and Sierra are fully regulated "public utilities," subject to the jurisdiction and oversight of the Commission and the Federal Energy Regulatory Commission ("FERC"). Jointly, Nevada Power and Sierra provide approximately 90 percent of Nevada's electrical power. Nevada Power and Sierra provide all-in electric service to residential, commercial, and industrial customers in northern and southern Nevada at rates and under terms and conditions reviewed and approved by the Commission. Nevada Power and Sierra also provide distribution-only service to very large commercial customers that have received

permission to procure their own energy through an alternative energy provider. Distribution-only service is provided to these large commercial customers at rates and under terms and conditions reviewed and approved by the Commission. Finally, Nevada Power and Sierra provide transmission service to customers who interconnect directly to the transmission system, or who use the transmission system to import or export energy into and out of Nevada. Transmission service is provided to transmission customers at rates and under terms and conditions reviewed and approved by the FERC.

The nearly 2,700 employees of Nevada Power and Sierra support the generation, transmission, and distribution of electric energy to over 1.4 million bundled customers statewide, covering more than 45,000 square miles. Together, Nevada Power and Sierra serve peak loads of 8,241 MW with capacity primarily sourced from a combination of a small fleet of Nevada-based modern, clean-burning natural gas facilities, more than 50 Nevada renewable resources, and market purchases. Between 2005 and today, the Companies have transitioned away from coal-fired generation entirely and dramatically increased the amount of renewable energy resources in their portfolio.

A map of Nevada Power's and Sierra's electric service territories, as well as the bulk transmission system that delivers energy into and out of Nevada is set forth below in Figure S-3.

**FIGURE S-3**
**NV ENERGY SERVICE TERRITORIES**




***Resource Planning Described.*** The Companies are required by statute to submit a joint IRP every three years, or more often if necessary, and present a preferred plan for meeting the long-term needs of customers. Like IRPs prepared in the past, this 2026 Joint IRP begins with projections of customers' load requirements and the resources the Companies own or have under contract with which they can serve customers' load requirements. The Companies then prepared a long-term plan in which they lay out in detail their proposals for filling projected needs with programs that reduce energy consumption and requests to build new renewable, storage, and thermal resources to serve the growing customer load and transmission to access these new resources as well as meet customers' needs. As mentioned above, the Companies' Preferred Plan in this 2026 Joint IRP proposes to meet the shortfall between load and resources with 4,370 MW of solar photovoltaic ("PV") generation, 5,405 MW of BESS, 180 MW of geothermal generation, and 1,223 MW of natural gas combustion turbines.[5]

[5] While Nevada Power and Sierra are separate legal entities, with separate service territories and unique revenue requirements and costs of service, the Companies used a simplifying assumption to prepare the 2026 Joint IRP.

***IRP and Action Plan Period.*** This 2026 Joint IRP filing addresses the 20-year planning period between 2027 and 2046, with a full 24-year study period extending to 2050.[6] The Companies' Preferred Plan and alternative plans are formulated and compared to one another using advanced economic analysis techniques. This 2026 Joint IRP includes an "Action Plan," which details the steps that the Companies will take over the three-year period January 1, 2027, to December 31, 2029, to implement the Preferred Plan. The Action Plan filed with this 2026 Joint IRP, attached as Exhibit A to the Joint Application, includes a description of the costs, timeline, and planning activities for each recommended project. A more detailed description of each project is provided in detailed narratives that are included in the 2026 Joint IRP.

## SECTION III - FORECAST OF GROWTH: NAC § 704.9215(2)(b)

***Summary of Findings.*** The load forecast for the 2026 Joint IRP covers calendar years 2027 through 2046 ("2026 Joint IRP Load Forecast") and incorporates data updates and incremental changes to the load forecast last approved by the Commission in the 2024 Joint IRP First Amendment in Docket No. 25-10028. The projected system growth included in this load forecast update is driven by large customer service requests, mainly data centers. These projects are concentrated in the industrial growth areas at the Tahoe Regional Industrial Center ("TRIC") at Sierra and Apex area at Nevada Power. This growth continues at an unprecedented level requiring step changes in company resources to meet these higher load requirements.

For the 2026 Joint IRP's 20-year forecast period (2027 through 2046), the Compound Annual Growth Rate ("CAGR") of the annual retail energy for the Companies is 4.9 percent (3.2 percent at Nevada Power and 6.9 percent at Sierra). Annual energy consumption increases by approximately 59,200 GWh for the combined NV Energy system, with 20,900 GWh at Nevada Power and 38,200 GWh at Sierra. The CAGR of the Companies' combined system coincident peak is 3.7 percent (with non-coincident peak CAGR values of 2.6 percent at Nevada Power and 5.6 percent at Sierra). System Peak Demand is expected to increase approximately 9,000 MW for

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Specifically, the Companies assumed that costs associated with proposed and placeholder resources located in Nevada Power's service territory are reflected in Nevada Power's revenue requirement. Likewise, the Companies assumed that costs associated with proposed and placeholder resources located in Sierra's service territory are reflected in Sierra's revenue requirement. This simplifying assumption reflects the uncertainty inherent in the Companies' load forecast and the core principle of ***joint*** resource planning – *i.e.*, planning for the needs of a single, integrated electric system serving northern and southern Nevada. The Base Minus informational case, coupled with the LLESA, provides new tools to address load forecast uncertainty. The Companies request a separate procedural schedule for Commission decisions on the applicability and terms of the LLESA; this approach will facilitate more informed decision-making in this proceeding. It can provide an opportunity for large load customers to commit to the terms of a Commission-approved planning and service framework, which will provide more certainty to the Companies' load forecast and allow for the appropriate allocation of interests in proposed resources.

[6] The Companies aligned the full study period with Nevada's policy goal for an amount of energy production from zero-carbon dioxide emission resources equal to the total amount of electricity sales in 2050.

the combined coincident system during this period, with non-coincident peaks of 4,300 MW at Nevada Power and 4,700 MW at Sierra. Sales growth outpaces growth in peak demand, indicating that the system-wide load shape is flattening as system utilization increases.

Below are several key highlights of the 2026 Joint IRP Load Forecast providing context for understanding their influence on the load forecast results. They include:

- The primary driver of growth in the 2026 Joint IRP Load Forecast is the continued unprecedented policy-driven load growth from the number and size of requests from large customer data center projects. The twenty-year, 2027-2046 period CAGR in the 2026 Joint IRP Load Forecast, based on peak values and reflecting these projects, is 2.6 percent at Nevada Power and 5.6 percent at Sierra. Without these projects, as presented in the alternate Base Minus scenario, the twenty-year, 2027-2046 period CAGR, based on peak values, is 1.7 percent at Nevada Power and 1.3 percent at Sierra.
- Data center projects have higher load factors, with relatively consistent energy use across all hours relative to peak demand. This load profile enables more efficient use of grid facilities, as data centers place greater pressure on overall energy requirements than on peak demand and increase utilization of fixed system resources. As a result, annual energy requirements are growing faster than peak demand, improving overall grid efficiency. The magnitude of this growth is significant, however, effectively requiring the Companies to serve loads roughly 2.5 times current levels by 2046.
- Data centers currently account for five percent of total NV Energy sales - three percent of total Nevada Power sales and 10 percent of total Sierra sales. By 2046, it is projected that data centers will account for 64 percent of total NV Energy sales - 42 percent at Nevada Power and 82 percent at Sierra.
- Projected electric vehicle adoption increases from 96,171 vehicles in 2025 to 703,577 vehicles by 2046. This equates to an increase from 3 percent of all vehicles in 2025 to 12 percent being electric vehicles by 2046.
- In this 2026 Joint IRP Load Forecast, an average of 1,177 Nevada Power and 170 Sierra Pacific residential customers become new solar, net energy metering ("NEM"), customers per month—until the solar adoption rate reaches 15 percent of total residential customers regionally (at which point, an annual reduction factor is applied to projected adoption rates). This equates to 395,136 total residential solar NEM customers in Nevada by 2046 with 3,000 MW of installed on-site generation.

The following table, Figure S-4, summarizes the forecasted annual energy gigawatt-hour ("GWh") sales and peak MW over the 2027–2046 period for the updated forecast. The combined

system peak is typically lower than the sum of the individual Nevada Power and Sierra peaks due to the peak hour occurring at different times between the two systems.

**FIGURE S-4**
**COMPANIES' ENERGY AND PEAK FORECAST SUMMARY**

| | Native Energy (GWh) | | | Peak (MW) | | |
|---|---|---|---|---|---|---|
| Year | NVE | NPC | Sierra | NVE | NPC | Sierra |
| 2027 | 39,896 | 25,038 | 14,858 | 9,114 | 6,705 | 2,598 |
| 2028 | 44,329 | 26,620 | 17,709 | 9,629 | 6,865 | 2,951 |
| 2029 | 49,402 | 28,859 | 20,543 | 10,511 | 7,369 | 3,242 |
| 2030 | 54,676 | 31,408 | 23,268 | 11,192 | 7,751 | 3,606 |
| 2031 | 62,196 | 32,542 | 29,654 | 12,183 | 7,993 | 4,375 |
| 2032 | 65,436 | 33,335 | 32,102 | 12,607 | 8,102 | 4,614 |
| 2033 | 68,221 | 34,000 | 34,221 | 12,798 | 8,227 | 4,951 |
| 2034 | 70,878 | 34,717 | 36,160 | 13,466 | 8,509 | 5,130 |
| 2035 | 73,644 | 35,438 | 38,205 | 13,897 | 8,628 | 5,355 |
| 2036 | 76,971 | 36,422 | 40,549 | 14,314 | 8,835 | 5,672 |
| 2037 | 79,268 | 37,440 | 41,828 | 14,790 | 9,052 | 5,829 |
| 2038 | 81,493 | 38,518 | 42,975 | 15,051 | 9,283 | 6,014 |
| 2039 | 83,720 | 39,535 | 44,184 | 15,237 | 9,389 | 6,218 |
| 2040 | 86,188 | 40,657 | 45,531 | 15,941 | 9,800 | 6,317 |
| 2041 | 88,347 | 41,713 | 46,634 | 16,253 | 9,968 | 6,480 |
| 2042 | 90,421 | 42,558 | 47,863 | 16,740 | 10,280 | 6,680 |
| 2043 | 92,497 | 43,356 | 49,141 | 17,049 | 10,344 | 6,786 |
| 2044 | 94,910 | 44,363 | 50,547 | 17,285 | 10,487 | 6,998 |
| 2045 | 96,850 | 45,113 | 51,736 | 17,782 | 10,820 | 7,145 |
| 2046 | 99,053 | 45,952 | 53,101 | 18,148 | 10,964 | 7,275 |
| CAGR | | | | | | |
| 2027-2029 | 11.3% | 7.4% | 17.6% | 7.4% | 4.8% | 11.7% |
| 2027-2036 | 7.6% | 4.3% | 11.8% | 5.1% | 3.1% | 9.1% |
| 2027-2046 | 4.9% | 3.2% | 6.9% | 3.7% | 2.6% | 5.6% |

***Population Growth.*** Both Companies' residential and Small C&I customer forecasts are driven by population. The 2026 Joint IRP Forecast is an extrapolation of historical population series using the annual growth rates using a blended average of growth rates from multiple sources.

Figure S-5 shows the population forecasts for Nevada Power and Sierra from 2027 through 2046. For the 20-year period from 2027 through 2046, the Nevada Power CAGR in the forecast is 0.9 percent. The Sierra CAGR in the forecast for that time period is 0.3 percent.

**FIGURE S-5**
**POPULATION FORECAST**

| | Population | | |
|---|---|---|---|
| Year | NVE | Nevada Power | Sierra |
| 2027 | 3,439,426 | 2,527,889 | 911,537 |
| 2028 | 3,480,247 | 2,563,650 | 916,598 |
| 2029 | 3,517,868 | 2,596,568 | 921,300 |
| 2030 | 3,553,407 | 2,627,542 | 925,865 |
| 2031 | 3,586,537 | 2,656,401 | 930,136 |
| 2032 | 3,617,697 | 2,683,602 | 934,095 |
| 2033 | 3,647,221 | 2,709,390 | 937,831 |
| 2034 | 3,675,230 | 2,733,942 | 941,288 |
| 2035 | 3,701,956 | 2,757,500 | 944,455 |
| 2036 | 3,727,457 | 2,780,120 | 947,337 |
| 2037 | 3,752,126 | 2,802,128 | 949,998 |
| 2038 | 3,775,881 | 2,823,396 | 952,485 |
| 2039 | 3,798,845 | 2,843,919 | 954,926 |
| 2040 | 3,821,024 | 2,863,778 | 957,246 |
| 2041 | 3,842,530 | 2,883,087 | 959,444 |
| 2042 | 3,863,500 | 2,901,926 | 961,574 |
| 2043 | 3,883,720 | 2,920,113 | 963,607 |
| 2044 | 3,904,208 | 2,938,580 | 965,628 |
| 2045 | 3,924,817 | 2,957,163 | 967,654 |
| 2046 | 3,945,548 | 2,975,864 | 969,684 |
| CAGR | | | |
| 2027-2029 | 1.1% | 1.3% | 0.5% |
| 2027-2036 | 0.9% | 1.1% | 0.4% |
| 2027-2046 | 0.7% | 0.9% | 0.3% |

***Employment and Output Trends.*** Population and real economic output drive the Small and Large C&I customer and sales forecasts. The state's economic growth is estimated to continue at 2.1 percent for Nevada Power and 1.5 percent at Sierra during the 2027 to 2036 period.

***Large customer assumptions.*** Large load customer growth in the 2026 Joint IRP Forecast reflects the continued unprecedented load growth expected from 50 bundled-service projects considered for this forecast. These projects are located primarily within the TRIC area at Sierra and the Apex area at Nevada Power. In total, these customers requested approximately 16,930 MW of capacity additions, with 11,710 MW at Sierra and 5,220 MW at Nevada Power. Thirty-nine of these projects are bundled-service high load factor data centers that have requested 16,530 MW of capacity and energy alone. Consistent with past practice, these requests are scaled down in the retail load

forecast. The loads of projects in the study phase saw an average overall reduction of 83 percent; the loads of projects with signed Rule 9 agreements were reduced by 38 percent.[7]

***Normal Weather***. Pursuant to NAC § 704.9281(1)(b), sales have been weather normalized for the 2026 Joint IRP Forecast. In this filing, the Companies adjusted hourly sales using calculated daily normal values for each month. The daily average temperature is used to calculate Cooling Degree Days ("CDD") and Heating Degree Days ("HDD") measurements for use in the modelling process. CDDs and HDDs are simply the number of degrees that the average daily temperature is above (for CDD) or below (for HDD) a set threshold, with the threshold determined statistically for each customer class. Those days when the average daily temperature is greater than the threshold are considered days when customers will increase cooling usage, while those days under the threshold will show increases related to heating usage. Calendar HDDs and CDDs are generated by summing the daily degree-days over the calendar month. Weather normalization for the 2026 Joint IRP Forecast utilized the monthly 20-year historical trended normal calculations for the determination of these normal weather assumptions over the 2004 to 2024 period.

***Distribution-Only Service.*** Very large commercial customers authorized to procure their own energy receive "wires only" service from Nevada Power and Sierra and are termed DOS customers. Because they have elected to procure their own energy, DOS customers must be separately accounted for in the Companies' load forecast. The 2026 Joint IRP Forecast has not removed any large customers who have moved to DOS as part of this update.

***Demand Side Management ("DSM") and Demand Reduction.*** For this 2026 Joint IRP forecast, the level of DSM program kWh savings incorporate those approved in the 2024 Joint IRP proceeding into the base forecast.

Figure S-6 summarizes the base forecast DSM savings by program for Nevada Power from years in the 2027-2046 range. Figure S-7 provides the same information for Sierra.

**FIGURE S-6**

| | 2027 | 2028 | 2029 | 2030 | 2035 | 2040 | 2045 | 2046 |
|---|---|---|---|---|---|---|---|---|
| Residential Portfolio | | | | | | | | |
| Residential DR Build (EE savings) | 5,000 | 5,000 | 5,000 | 5,000 | 5,000 | 5,000 | 5,000 | 5,000 |
| Residential DR Manage (EE savings) | 31,000 | 32,250 | 33,500 | 34,750 | 41,000 | 47,250 | 53,500 | 54,750 |
| Total Residential Portfolio | 36,000 | 37,250 | 38,500 | 39,750 | 46,000 | 52,250 | 58,500 | 59,750 |
| | | | | | | | | |
| Commercial Portfolio | | | | | | | | |
| Commercial DR Build (EE savings) | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 |
| Commercial DR Manage (EE savings) | 6,200 | 6,450 | 6,700 | 6,950 | 8,200 | 9,450 | 10,700 | 10,950 |
| Total Commercial Portfolio | 7,200 | 7,450 | 7,700 | 7,950 | 9,200 | 10,450 | 11,700 | 11,950 |
| | | | | | | | | |
| Total Residential and Commercial | 43,200 | 44,700 | 46,200 | 47,700 | 55,200 | 62,700 | 70,200 | 71,700 |

[7] The adjustment percentages will vary by individual project and year. The overall percentages include one customer who signed a letter of intent and is included at 100 percent of their request. Excluding this customer, the overall average reduction percentage for projects with a signed agreement is approximately 43 percent in this load forecast update.

## NEVADA POWER DSM SAVINGS BY PROGRAM

### FIGURE S-7
### SIERRA DSM SAVINGS BY PROGRAM

| | 2027 | 2028 | 2029 | 2030 | 2035 | 2040 | 2045 | 2046 |
|---|---|---|---|---|---|---|---|---|
| Residential Portfolio | | | | | | | | |
| Residential DR Build (EE savings) | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 |
| Residential DR Manage (EE savings) | 3,800 | 4,050 | 4,300 | 4,550 | 5,800 | 7,050 | 8,300 | 8,550 |
| Total Residential Portfolio | 4,800 | 5,050 | 5,300 | 5,550 | 6,800 | 8,050 | 9,300 | 9,550 |
| | | | | | | | | |
| Commercial Portfolio | | | | | | | | |
| Commercial DR Build (EE savings) | 115 | 115 | 115 | 115 | 115 | 115 | 115 | 115 |
| Commercial DR Manage (EE savings) | 1,900 | 1,929 | 1,958 | 1,986 | 2,130 | 2,274 | 2,418 | 2,446 |
| Total Commercial Portfolio | 2,015 | 2,044 | 2,073 | 2,101 | 2,245 | 2,389 | 2,533 | 2,561 |
| | | | | | | | | |
| Total Residential and Commercial | 6,815 | 7,094 | 7,373 | 7,651 | 9,045 | 10,439 | 11,833 | 12,111 |

***Net-Energy Metering.*** The Companies include a separate NEM customer-owned generation forecast for rooftop solar customers in this filing. In this update, similar to in the 2024 Joint IRP 1st Amendment Load Forecast, recent historical trends are used to forecast NEM customer and sales growth, and the shift from full-requirement to partial-requirement customers is reflected in the overall sales forecast. Based on projected installed capacities of 1,246 MW for Nevada Power and 129 MW for Sierra, incremental peak reductions of 12 MW and 9 MW, respectively, are expected by 2027.

Consistent with the 2024 Joint IRP 1st Amendment Load Forecast methodology, no separate adjustments are made for behind-the-meter energy storage due to limited data on customer operating characteristics. Storage impacts will be incorporated in future forecasts once sufficient hourly operating data are available to demonstrate materially different usage patterns relative to the broader NEM customer base.

***Low, Base Minus, Base, Base Plus, and High Scenarios.*** Consistent with prior practice (and Commission regulations), high and low load forecast scenarios were developed for the 2026 Joint IRP Forecast. The high and low load forecast scenarios are based on different assumptions of economic, demographic, NEM adoption, electric vehicle ("EV") loads, and large customer growth than the base forecast. In addition to those scenarios, NV Energy developed two more scenarios, Base Minus and Base Plus. The Base Minus forecast begins with NV Energy's Base Load Forecast then removes 39 large load service requests associated with the related artificial intelligence ("AI") boom in infrastructure development. All other variables that drive the load forecast model – *e.g.*, macroeconomic and demographic inputs – were held constant between the Base Load Forecast and the Base Minus case. This approach is designed to isolate the impact of large load service requests on the supply side expansion plan. Similarly, the Base Plus scenario considers the impact

of unmitigated requested levels of Large Customer Major Project load for those projects with signed agreements.

***704B Annual Limits.*** The 2026 Joint IRP Forecast includes the calculation of annual limits for both Nevada Power and Sierra Large Commercial and Industrial ("C&I") customers who are eligible to choose to exit bundled service and purchase energy from a third-party provider pursuant to NRS Chapter 704B. In this proceeding, the annual limits proposed are 58,133 MWh at Nevada Power and 0 MWh at Sierra, due to current transmission system import capacity constraints.

***Required Figures.*** The regulations governing resource planning require that certain figures are included in the IRP Summary. Figures S-8 and S-9 show the forecast of peak demand and energy sales for each of the 20 years in the planning period, under the low, base minus, base, base plus, and high scenarios, with and without DSM, for Nevada Power and Sierra respectively. Solar PV is not classified as DSM and is, therefore, included in both, with and without DSM, scenarios.

## FIGURE S-8
## NEVADA POWER LOW, BASE MINUS, BASE, BASE PLUS, AND HIGH PEAK DEMAND AND SALES SCENARIOS WITH AND WITHOUT DSM

| | Peak Demand (MW) With DSM/EE | | | | | Peak Demand (MW) Without DSM/EE | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | Low | Base Minus | Base | Base Plus | High | Low | Base Minus | Base | Base Plus | High |
| 2027 | 6,296 | 6,382 | 6,705 | 6,836 | 6,956 | 6,451 | 6,538 | 6,862 | 6,994 | 7,118 |
| 2028 | 6,260 | 6,369 | 6,865 | 7,051 | 7,192 | 6,487 | 6,601 | 7,082 | 7,274 | 7,395 |
| 2029 | 6,487 | 6,619 | 7,369 | 7,761 | 7,916 | 6,732 | 6,865 | 7,612 | 8,003 | 8,152 |
| 2030 | 6,609 | 6,740 | 7,751 | 8,162 | 8,325 | 6,878 | 7,002 | 8,009 | 8,420 | 8,590 |
| 2031 | 6,750 | 6,883 | 7,993 | 8,345 | 8,510 | 6,988 | 7,120 | 8,231 | 8,583 | 8,747 |
| 2032 | 6,796 | 6,923 | 8,102 | 8,432 | 8,625 | 7,133 | 7,260 | 8,435 | 8,764 | 8,949 |
| 2033 | 6,877 | 6,987 | 8,227 | 8,530 | 8,745 | 7,255 | 7,365 | 8,601 | 8,903 | 9,109 |
| 2034 | 7,055 | 7,192 | 8,509 | 8,788 | 9,004 | 7,450 | 7,586 | 8,900 | 9,178 | 9,385 |
| 2035 | 7,101 | 7,240 | 8,628 | 8,877 | 9,111 | 7,544 | 7,684 | 9,068 | 9,316 | 9,540 |
| 2036 | 7,235 | 7,392 | 8,835 | 9,050 | 9,289 | 7,677 | 7,834 | 9,273 | 9,487 | 9,716 |
| 2037 | 7,352 | 7,526 | 9,052 | 9,235 | 9,497 | 7,818 | 7,992 | 9,513 | 9,695 | 9,945 |
| 2038 | 7,528 | 7,693 | 9,283 | 9,431 | 9,685 | 7,868 | 8,033 | 9,623 | 9,772 | 10,025 |
| 2039 | 7,546 | 7,719 | 9,389 | 9,507 | 9,789 | 8,034 | 8,207 | 9,877 | 9,995 | 10,270 |
| 2040 | 7,785 | 8,023 | 9,800 | 9,885 | 10,204 | 8,270 | 8,507 | 10,279 | 10,364 | 10,670 |
| 2041 | 7,894 | 8,120 | 9,968 | 10,008 | 10,337 | 8,390 | 8,604 | 10,456 | 10,496 | 10,819 |
| 2042 | 8,117 | 8,395 | 10,280 | 10,317 | 10,644 | 8,461 | 8,739 | 10,624 | 10,661 | 10,988 |
| 2043 | 8,114 | 8,406 | 10,344 | 10,384 | 10,751 | 8,618 | 8,911 | 10,848 | 10,889 | 11,243 |
| 2044 | 8,208 | 8,511 | 10,487 | 10,533 | 10,901 | 8,570 | 8,873 | 10,849 | 10,895 | 11,262 |
| 2045 | 8,416 | 8,750 | 10,820 | 10,867 | 11,274 | 8,927 | 9,262 | 11,329 | 11,376 | 11,768 |
| 2046 | 8,482 | 8,837 | 10,964 | 11,011 | 11,436 | 9,000 | 9,355 | 11,482 | 11,529 | 11,953 |

| | Annual Usage (GWH) With DSM/EE | | | | | Annual Usage (GWH) Without DSM/EE | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | Low | Base Minus | Base | Base Plus | High | Low | Base Minus | Base | Base Plus | High |
| 2027 | 22,103 | 22,271 | 25,038 | 26,202 | 26,569 | 23,724 | 23,893 | 26,659 | 27,824 | 28,191 |
| 2028 | 22,223 | 22,442 | 26,620 | 28,230 | 28,702 | 24,108 | 24,328 | 28,505 | 30,116 | 30,587 |
| 2029 | 22,363 | 22,595 | 28,859 | 32,254 | 32,791 | 24,462 | 24,694 | 30,958 | 34,353 | 34,889 |
| 2030 | 22,617 | 22,796 | 31,408 | 34,969 | 35,544 | 24,933 | 25,113 | 33,725 | 37,286 | 37,859 |
| 2031 | 22,831 | 22,985 | 32,542 | 35,585 | 36,227 | 25,361 | 25,516 | 35,073 | 38,116 | 38,756 |
| 2032 | 23,116 | 23,228 | 33,335 | 36,179 | 36,906 | 25,857 | 25,970 | 36,077 | 38,921 | 39,645 |
| 2033 | 23,288 | 23,396 | 34,000 | 36,609 | 37,373 | 26,224 | 26,334 | 36,938 | 39,547 | 40,306 |
| 2034 | 23,446 | 23,573 | 34,717 | 37,087 | 37,873 | 26,583 | 26,712 | 37,856 | 40,225 | 41,006 |
| 2035 | 23,625 | 23,709 | 35,438 | 37,557 | 38,444 | 26,960 | 27,045 | 38,774 | 40,893 | 41,772 |
| 2036 | 23,904 | 24,049 | 36,422 | 38,279 | 39,185 | 27,409 | 27,556 | 39,928 | 41,785 | 42,683 |
| 2037 | 24,195 | 24,403 | 37,440 | 39,011 | 39,970 | 27,758 | 27,967 | 41,004 | 42,575 | 43,525 |
| 2038 | 24,540 | 24,795 | 38,518 | 39,812 | 40,862 | 28,167 | 28,424 | 42,146 | 43,441 | 44,480 |
| 2039 | 24,882 | 25,176 | 39,535 | 40,560 | 41,704 | 28,570 | 28,865 | 43,224 | 44,249 | 45,382 |
| 2040 | 25,224 | 25,597 | 40,657 | 41,396 | 42,634 | 28,977 | 29,350 | 44,411 | 45,149 | 46,375 |
| 2041 | 25,498 | 25,920 | 41,713 | 42,061 | 43,423 | 29,294 | 29,717 | 45,510 | 45,858 | 47,207 |
| 2042 | 25,822 | 26,330 | 42,558 | 42,876 | 44,326 | 29,672 | 30,179 | 46,408 | 46,725 | 48,161 |
| 2043 | 26,155 | 26,734 | 43,356 | 43,705 | 45,281 | 30,052 | 30,631 | 47,253 | 47,602 | 49,162 |
| 2044 | 26,534 | 27,249 | 44,363 | 44,757 | 46,375 | 30,487 | 31,201 | 48,316 | 48,709 | 50,309 |
| 2045 | 26,745 | 27,576 | 45,113 | 45,507 | 47,186 | 30,732 | 31,563 | 49,100 | 49,494 | 51,154 |
| 2046 | 27,022 | 27,922 | 45,952 | 46,348 | 48,178 | 31,052 | 31,951 | 49,981 | 50,377 | 52,187 |

## FIGURE S-9
## SIERRA LOW, BASE MINUS, BASE, BASE PLUS, AND HIGH PEAK DEMAND AND SALES SCENARIOS WITH AND WITHOUT DSM

| | Peak Demand (MW) With DSM/EE | | | | | Peak Demand (MW) Without DSM/EE | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | Low | Base Minus | Base | Base Plus | High | Low | Base Minus | Base | Base Plus | High |
| 2027 | 2,238 | 2,253 | 2,598 | 3,309 | 3,321 | 2,271 | 2,286 | 2,630 | 3,342 | 3,354 |
| 2028 | 2,227 | 2,254 | 2,951 | 3,694 | 3,708 | 2,270 | 2,297 | 2,996 | 3,745 | 3,759 |
| 2029 | 2,261 | 2,288 | 3,242 | 4,043 | 4,062 | 2,301 | 2,328 | 3,284 | 4,091 | 4,110 |
| 2030 | 2,360 | 2,383 | 3,606 | 4,564 | 4,581 | 2,403 | 2,425 | 3,652 | 4,616 | 4,632 |
| 2031 | 2,402 | 2,424 | 4,375 | 5,509 | 5,529 | 2,447 | 2,468 | 4,423 | 5,564 | 5,584 |
| 2032 | 2,392 | 2,407 | 4,614 | 5,882 | 5,905 | 2,435 | 2,449 | 4,662 | 5,937 | 5,959 |
| 2033 | 2,454 | 2,474 | 4,951 | 6,349 | 6,375 | 2,501 | 2,521 | 5,006 | 6,411 | 6,437 |
| 2034 | 2,420 | 2,436 | 5,130 | 6,611 | 6,642 | 2,467 | 2,483 | 5,186 | 6,674 | 6,705 |
| 2035 | 2,457 | 2,471 | 5,355 | 7,031 | 7,069 | 2,509 | 2,522 | 5,414 | 7,097 | 7,136 |
| 2036 | 2,527 | 2,546 | 5,672 | 7,530 | 7,571 | 2,582 | 2,600 | 5,734 | 7,596 | 7,638 |
| 2037 | 2,528 | 2,549 | 5,829 | 7,660 | 7,704 | 2,585 | 2,605 | 5,886 | 7,724 | 7,768 |
| 2038 | 2,553 | 2,579 | 6,014 | 7,828 | 7,882 | 2,613 | 2,639 | 6,080 | 7,903 | 7,957 |
| 2039 | 2,632 | 2,663 | 6,218 | 7,988 | 8,046 | 2,692 | 2,723 | 6,283 | 8,061 | 8,119 |
| 2040 | 2,605 | 2,641 | 6,317 | 8,044 | 8,103 | 2,658 | 2,694 | 6,375 | 8,110 | 8,169 |
| 2041 | 2,694 | 2,735 | 6,480 | 8,151 | 8,221 | 2,752 | 2,793 | 6,538 | 8,214 | 8,286 |
| 2042 | 2,749 | 2,796 | 6,680 | 8,307 | 8,381 | 2,808 | 2,855 | 6,739 | 8,366 | 8,440 |
| 2043 | 2,738 | 2,786 | 6,786 | 8,355 | 8,436 | 2,798 | 2,846 | 6,845 | 8,415 | 8,496 |
| 2044 | 2,766 | 2,823 | 6,998 | 8,510 | 8,600 | 2,826 | 2,883 | 7,058 | 8,574 | 8,665 |
| 2045 | 2,770 | 2,833 | 7,145 | 8,592 | 8,673 | 2,824 | 2,888 | 7,199 | 8,651 | 8,732 |
| 2046 | 2,806 | 2,881 | 7,275 | 8,638 | 8,732 | 2,867 | 2,942 | 7,336 | 8,698 | 8,793 |

| | Annual Usage (GWH) With DSM/EE | | | | | Annual Usage (GWH) Without DSM/EE | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | Low | Base Minus | Base | Base Plus | High | Low | Base Minus | Base | Base Plus | High |
| 2027 | 11,803 | 11,868 | 14,858 | 21,050 | 21,111 | 12,085 | 12,150 | 15,140 | 21,332 | 21,393 |
| 2028 | 11,668 | 11,795 | 17,709 | 24,240 | 24,297 | 12,010 | 12,137 | 18,052 | 24,582 | 24,639 |
| 2029 | 12,132 | 12,254 | 20,543 | 27,675 | 27,728 | 12,530 | 12,652 | 20,941 | 28,074 | 28,126 |
| 2030 | 12,531 | 12,599 | 23,268 | 31,787 | 31,832 | 12,986 | 13,053 | 23,722 | 32,241 | 32,286 |
| 2031 | 12,651 | 12,683 | 29,654 | 39,552 | 39,616 | 13,160 | 13,193 | 30,164 | 40,062 | 40,126 |
| 2032 | 12,786 | 12,798 | 32,102 | 43,224 | 43,300 | 13,352 | 13,364 | 32,668 | 43,790 | 43,866 |
| 2033 | 12,817 | 12,823 | 34,221 | 46,397 | 46,484 | 13,435 | 13,441 | 34,839 | 47,015 | 47,102 |
| 2034 | 12,889 | 12,860 | 36,160 | 49,031 | 49,159 | 13,559 | 13,530 | 36,830 | 49,701 | 49,830 |
| 2035 | 12,972 | 12,941 | 38,205 | 53,003 | 53,142 | 13,691 | 13,659 | 38,924 | 53,721 | 53,860 |
| 2036 | 13,116 | 13,081 | 40,549 | 56,881 | 57,030 | 13,886 | 13,850 | 41,319 | 57,651 | 57,799 |
| 2037 | 13,162 | 13,138 | 41,828 | 57,790 | 57,958 | 13,978 | 13,955 | 42,645 | 58,607 | 58,775 |
| 2038 | 13,284 | 13,268 | 42,975 | 58,734 | 58,930 | 14,138 | 14,122 | 43,829 | 59,589 | 59,784 |
| 2039 | 13,440 | 13,436 | 44,184 | 59,557 | 59,764 | 14,305 | 14,300 | 45,049 | 60,422 | 60,629 |
| 2040 | 13,629 | 13,642 | 45,531 | 60,566 | 60,786 | 14,507 | 14,520 | 46,409 | 61,444 | 61,664 |
| 2041 | 13,777 | 13,786 | 46,634 | 61,239 | 61,494 | 14,664 | 14,672 | 47,521 | 62,126 | 62,381 |
| 2042 | 13,952 | 13,971 | 47,863 | 62,024 | 62,298 | 14,850 | 14,869 | 48,761 | 62,922 | 63,196 |
| 2043 | 14,126 | 14,161 | 49,141 | 62,832 | 63,123 | 15,035 | 15,071 | 50,050 | 63,742 | 64,032 |
| 2044 | 14,283 | 14,332 | 50,547 | 63,721 | 64,032 | 15,206 | 15,255 | 51,469 | 64,644 | 64,955 |
| 2045 | 14,335 | 14,438 | 51,736 | 64,307 | 64,596 | 15,267 | 15,370 | 52,668 | 65,239 | 65,526 |
| 2046 | 14,428 | 14,560 | 53,101 | 65,109 | 65,401 | 15,370 | 15,500 | 54,042 | 66,050 | 66,341 |

## SECTION IV - DEMAND SIDE PLAN SUMMARY: NAC § 704.9215(2)(c)

The DSM Plan as part of the 2026 Joint IRP continues the exploration and development of portfolio design and concepts that were presented in the 2024 Joint IRP. The proposed Plan's programs, services, and participation incentives are beneficial to the grid and to customers; however, stakeholders and the Commission generally expressed that more detailed information is needed about the programs' cost effectiveness and how grid services and benefits would be quantified. The contents of the DSM Plan include energy and demand savings targets, new DSMore modeling and variables to quantify cost-effectiveness, new incentive structures for behind-the-meter measures, demonstrating how incentive payments are calculated under the proposed incentive framework filed separately in the Grid Services Rider tariff advice letters, further integration with the distributed resources plan ("DRP"), and collaboration with the DSM Collaborative group on various topics such as large load customer programs.

The proposed DSM Portfolio has net benefits for ratepayers, includes programs to serve all customers with an emphasis on income-qualified and historically underserved communities ("HUC"), and strikes the most appropriate balance among energy savings, demand reduction, resource adequacy, cost-effectiveness of those savings, customer rate impacts, and capability to provide enhanced locational net benefits for the distribution grid as explained in the DRP.

The DSM Plan incorporates Option Value and avoided costs of Greenhouse Gas emissions ("GHG") and Criteria Air Pollutants ("CAP") into its DSMore cost-effectiveness model. The plan uses the "NTRC 2.0" test, which is a version of the existing Non-energy benefit Total Resource Cost ("NTRC") test that has been expanded to include these newly quantified and modeled Option Value, GHG, and CAP benefits.

The investment represented by the proposed DSM Plan has a non-energy benefit total resource cost ("NTRC") benefits-to-cost ratio of 2.85 and will bring a net benefit of $897.9 million to the communities served by NV Energy. Figure S-10 below provides the proposed budget dollars and target energy savings for Nevada Power, Sierra, and the combined Companies. Additionally, in Figure S-11, NV Energy provides the projected Action Plan period NTRC cost-effectiveness ratios for each program presented in the proposed DSM Portfolio. NV Energy is requesting specific approval of the proposed budgets and energy savings for the 2027-2029 DSM Plan period.

## FIGURE S-10
## PROPOSED PORTFOLIO BUDGETS, TARGETS, AND KEY METRICS

| | 2027 | 2028 | 2029 | Action Plan Total |
|---|---|---|---|---|
| **Nevada Power** | | | | |
| Budget ($) | 56,007,000 | 60,810,000 | 66,352,000 | 183,169,000 |
| Energy Savings Target (kWh) | 179,054,000 | 181,540,000 | 184,786,000 | 545,380,000 |
| Dispatchable Demand Reduction Impact (kW) | 42,450 | 44,950 | 46,950 | 134,349 |
| NTRC 2.0 Net Benefits | 300,789,388 | 324,002,682 | 352,410,333 | 977,202,403 |
| NTRC 2.0 Ratio [2] | 3.60 | 3.59 | 3.62 | 3.60 |
| NTRC Net Benefits | 231,205,892 | 248,886,729 | 269,840,542 | 749,933,163 |
| NTRC Ratio | 3.00 | 2.99 | 3.01 | 3.00 |
| **Sierra** | | | | |
| Budget ($) | 15,690,000 | 18,554,000 | 20,855,000 | 55,099,000 |
| Energy Savings Target (kWh) | 47,119,000 | 47,529,000 | 47,727,000 | 142,375,000 |
| Dispatchable Demand Reduction Impact (kW) | 9,130 | 13,260 | 13,760 | 36,150 |
| NTRC 2.0 Net Benefits | 62,404,076 | 71,906,939 | 80,581,943 | 214,892,959 |
| NTRC 2.0 Ratio [2] | 3.09 | 2.93 | 2.87 | 2.95 |
| NTRC Net Benefits | 41,808,127 | 49,668,605 | 56,514,367 | 147,991,098 |
| NTRC Ratio | 2.40 | 2.33 | 2.31 | 2.34 |
| **NV Energy** | | | | |
| Budget ($) | 71,697,000 | 79,364,000 | 87,207,000 | 238,268,000 |
| Energy Savings Target (kWh) | 226,173,000 | 229,069,000 | 232,513,000 | 687,755,000 |
| Dispatchable Demand Reduction Impact (kW) | 51,580 | 58,210 | 60,710 | 170,500 |
| NTRC 2.0 Net Benefits | 363,193,465 | 395,909,621 | 432,992,277 | 1,192,095,362 |
| NTRC 2.0 Ratio [2] | 3.50 | 3.44 | 3.44 | 3.46 |
| NTRC Net Benefits | 273,014,019 | 298,555,334 | 326,354,909 | 897,924,261 |
| NTRC Ratio | **2.88** | **2.84** | **2.84** | **2.85** |

[1] The values in this table may not sum due to rounding

[2] NTRC that takes into consideration additional benefits. See Section 4 for more information.

**FIGURE S-11**
**2027-2029 DSM PORTFOLIO PROPOSED NTRC RATIOS NV ENERGY**

| Programs | NTRC | | | NTRC 2.0 | | |
|---|---|---|---|---|---|---|
| | 2027 | 2028 | 2029 | 2027 | 2028 | 2029 |
| **NV Energy** | | | | | | |
| Energy Education [1] | N/A | N/A | N/A | N/A | N/A | N/A |
| Energy Reports | 2.53 | 2.14 | 1.87 | 3.87 | 3.27 | 3.05 |
| Program Development [2] | N/A | N/A | N/A | N/A | N/A | N/A |
| **Education Services Total** | **1.30** | **1.16** | **1.06** | **1.99** | **1.78** | **1.73** |
| Energy Assessments & Direct Install | 0.89 | 0.78 | 0.69 | 1.34 | 1.22 | 1.14 |
| Residential HVAC & Heat Pumps | 0.88 | 0.82 | 0.75 | 1.16 | 1.10 | 1.04 |
| Home Energy Saver | 0.57 | 0.50 | 0.50 | 1.06 | 1.00 | 1.01 |
| Low Income | 0.32 | 0.29 | 0.27 | 0.40 | 0.37 | 0.34 |
| **Residential Services Total** | **3.15** | **3.12** | **3.08** | **3.37** | **3.35** | **3.32** |
| Energy Smart Schools | 1.71 | 1.42 | 1.23 | 2.75 | 2.40 | 2.17 |
| Business Energy Services | 2.56 | 2.25 | 2.14 | 4.92 | 4.68 | 4.64 |
| Non-Residential Services Total | 2.48 | 2.17 | 2.04 | 3.76 | 3.63 | 3.68 |
| Residential DR - Build | 2.90 | 2.93 | 2.89 | 3.05 | 3.11 | 3.07 |
| Residential DR - Manage | 4.36 | 4.27 | 4.22 | 4.58 | 4.49 | 4.46 |
| Battery Storage DR | 2.25 | 2.51 | 2.49 | 2.25 | 2.51 | 2.49 |
| Schools DR | 2.35 | 2.22 | 2.23 | 2.41 | 2.29 | 2.31 |
| Agricultural DR | 1.33 | 1.49 | 1.28 | 1.34 | 1.50 | 1.29 |
| Commercial DR - Build | 2.21 | 2.40 | 2.33 | 2.24 | 2.42 | 2.36 |
| Commercial DR - Manage | 4.30 | 4.80 | 4.90 | 4.75 | 5.09 | 5.15 |
| Demand Response Total | **3.52** | **3.52** | **3.54** | **3.70** | **3.69** | **3.72** |
| **NV Energy Total** | **2.88** | **2.84** | **2.84** | **3.50** | **3.44** | **3.44** |

[1] Energy (kWh) and demand (kW) savings are not tracked for this program because behavioral programs can be challenging to correlate, evaluate, and calculate associated energy savings.
[2] Energy (kWh) and demand (kW) savings are not tracked for this program because it is predicated on testing and trials of new potential programs and/or technologies.

Tables S-12 through S-15 represent the forecasted megawatt reductions for the proposed programs in the DSM Portfolio. Tables S-12 and S-13 cover the programs in Nevada Power's service territory, and Tables S-14 and S-15 cover the programs in Sierra's service territory.

## FIGURE S-12
## 2027-2036 NEVADA POWER DSM FORECASTED REDUCTIONS

| | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Programs** | **Forecasted Reductions (MW)** | | | | | | | | | |
| Energy Assessments & Direct Install | 0.88 | 1.0 | 1.1 | 1.1 | 1.1 | 1.1 | 1.2 | 1.2 | 1.2 | 1.3 |
| Energy Education | - | - | - | - | - | - | - | - | - | - |
| Energy Reports | 10.1 | 11.6 | 12.8 | 13.1 | 13.4 | 13.7 | 14.1 | 14.4 | 14.8 | 15.2 |
| Low Income | 0.12 | 0.03 | 0.15 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Program Development | - | - | - | - | - | - | - | - | - | - |
| Home Energy Saver | 1.8 | 2.0 | 2.2 | 2.3 | 2.3 | 2.4 | 2.5 | 2.5 | 2.6 | 2.6 |
| Residential HVAC & Heat Pumps | 4.3 | 4.8 | 5.3 | 5.4 | 5.5 | 5.7 | 5.8 | 6.0 | 6.1 | 6.3 |
| Business Energy Services | 12.9 | 14.1 | 15.6 | 15.9 | 16.3 | 16.8 | 17.2 | 17.6 | 18.0 | 18.5 |
| Energy Smart Schools | 3.4 | 4.3 | 5.3 | 5.5 | 5.6 | 5.7 | 5.9 | 6.0 | 6.2 | 6.3 |

## FIGURE S-13
## 2037-2046 NEVADA POWER DSM FORECASTED REDUCTIONS

| | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 |
|---|---|---|---|---|---|---|---|---|---|---|
| Programs | Forecasted Reductions (MW) | | | | | | | | | |
| Energy Assessments & Direct Install | 1.3 | 1.3 | 1.3 | 1.4 | 1.4 | 1.5 | 1.5 | 1.5 | 1.6 | 1.6 |
| Energy Education | - | - | - | - | - | - | - | - | - | - |
| Energy Reports | 15.6 | 15.9 | 16.3 | 16.8 | 17.2 | 17.6 | 18.0 | 18.5 | 19.0 | 19.4 |
| Low Income | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Program Development | - | - | - | - | - | - | - | - | - | - |
| Home Energy Saver | 2.7 | 2.8 | 2.8 | 2.9 | 3.0 | 3.1 | 3.1 | 3.2 | 3.3 | 3.4 |
| Residential HVAC & Heat Pumps | 6.4 | 6.6 | 6.7 | 6.9 | 7.1 | 7.3 | 7.4 | 7.6 | 7.8 | 8.0 |
| Business Energy Services | 19.0 | 19.4 | 19.9 | 20.4 | 20.9 | 21.4 | 22.0 | 22.5 | 23.1 | 23.7 |
| Energy Smart Schools | 6.5 | 6.6 | 6.8 | 7.0 | 7.2 | 7.3 | 7.5 | 7.7 | 7.9 | 8.1 |

**FIGURE S-14**
**2027-2036 SIERRA DSM FORECASTED REDUCTIONS**

| | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 |
|---|---|---|---|---|---|---|---|---|---|---|
| Programs | Forecasted Reductions (MW) | | | | | | | | | |
| Energy Assessments & Direct Install | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Energy Education | - | - | - | - | - | - | - | - | - | - |
| Energy Reports | 2.9 | 3.1 | 3.5 | 3.5 | 3.6 | 3.7 | 3.8 | 3.9 | 4.0 | 4.1 |
| Low Income | 0.03 | 0.03 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 |
| Program Development | - | - | - | - | - | - | - | - | - | - |
| Home Energy Saver | 0.37 | 0.41 | 0.45 | 0.46 | 0.47 | 0.48 | 0.49 | 0.51 | 0.52 | 0.53 |
| Residential HVAC & Heat Pumps | 0.65 | 0.72 | 0.79 | 0.81 | 0.83 | 0.85 | 0.87 | 0.89 | 0.91 | 0.94 |
| Business Energy Services | 4.9 | 5.4 | 6.0 | 6.1 | 6.3 | 6.4 | 6.6 | 6.8 | 6.9 | 7.1 |
| Energy Smart Schools | 0.76 | 0.83 | 0.92 | 0.94 | 0.96 | 0.99 | 1.01 | 1.04 | 1.1 | 1.1 |

**FIGURE S-15**
**2037-2046 SIERRA DSM FORECASTED REDUCTIONS (MW)**

| | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 |
|---|---|---|---|---|---|---|---|---|---|---|
| Programs | Forecasted Reductions (MW) | | | | | | | | | |
| Energy Assessments & Direct Install | 0.10 | 0.10 | 0.11 | 0.11 | 0.11 | 0.11 | 0.12 | 0.12 | 0.12 | 0.13 |
| Energy Education | - | - | - | - | - | - | - | - | - | - |
| Energy Reports | 4.22 | 4.3 | 4.4 | 4.5 | 4.7 | 4.8 | 4.9 | 5.0 | 5.1 | 5.3 |
| Low Income | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.06 | 0.06 |
| Program Development | - | - | - | - | - | - | - | - | - | - |
| Home Energy Saver | 0.55 | 0.56 | 0.57 | 0.59 | 0.60 | 0.62 | 0.63 | 0.65 | 0.67 | 0.68 |
| Residential HVAC & Heat Pumps | 0.96 | 1.0 | 1.0 | 1.0 | 1.1 | 1.1 | 1.1 | 1.1 | 1.2 | 1.2 |
| Business Energy Services | 7.28 | 7.5 | 7.6 | 7.8 | 8.0 | 8.2 | 8.4 | 8.7 | 8.9 | 9.1 |
| Energy Smart Schools | 1.11 | 1.1 | 1.2 | 1.2 | 1.2 | 1.3 | 1.3 | 1.3 | 1.4 | 1.4 |

As required by a directive from the 2024 Joint IRP, NV Energy filed an informational report that proposed an attainable demand savings goal with an approved incremental $3 million budget increase in addition to the Commission-approved 2024 demand response program budgets. This informational demand savings goal was formulated with input from the DSM Collaborative and was filed in Docket No. 25-11009. In the 2026 Join IRP, NV Energy proposes new budgets, programs, measures, and strategies. Pursuant to NAC § 704.9212(1)(b), NV Energy requests that the Commission review and accept an energy savings goal that proposes a combination of energy savings, in kWh, and incremental demand reduction capacity, in kW, during the Action Plan period that reflects the additional information, cost effectiveness testing, and program designs in the DSM Plan. The proposed DSM Portfolio implements a demand savings target reduction of 171

incremental new dispatchable MW with a kWh savings target of 687,755,000 for the three-year period.

New demand response programs and distributed energy resource ("DER") measures of the DSM Plan were carefully evaluated and planned to strategically coordinate with NV Energy's Hosting Capacity and Non-Wires Alternatives ("NWA") analyses contained with the DRP Plan. Recent improvements of the integration between the DSM and DRP Plans include the incorporation of behind-the-meter solar and storage assets into NWA analysis coupled with new incentive payment structures proposed in the DSM Plan and demand response capacity and energy savings incentives proposed in separately filed Grid Services Rider tariff advice letters. The DSM Plan's new incentives are intended to encourage purchases and installation of DERs by home and business owners which will increase the amount of demand response and energy storage assets available to NWA analyses.

Senate Bill 448 (2021) directs NV Energy to propose a portfolio that expends no less than 10 percent of its total expenditures on programs directed to low-income customers or those that reside in historically underserved communities. In this Plan, NV Energy provides results for the 2025 Program Year that satisfy this requirement and sets forth how this goal will be met during the 2027 through 2029 Action Plan period.

## SECTION V - SUMMARY OF THE PREFERRED PLAN: NAC § 704.9215(2)(d)

NAC § 704.937(8) requires that "the utility shall identify its preferred plan and fully justify its choice by setting forth the criteria that influenced the utility's choice." NAC § 704.937(6) requires that "the utility shall consider for each alternative plan the mitigation of risk by means of (a) flexibility; (b) diversity; (c) reduced size of commitments; (d) choice of projects that can be completed in short periods; (e) displacement of fuel; (f) reliability; (g) selection of fuel and energy supply portfolios; and (h) financial instruments or electricity products." NAC § 704.948 requires that "a utility shall analyze its decisions, taking into account its assessment of risk and identifying particular risks with respect to: (a) costs; (b) reliability; (c) finances; (d) the volatility of the price of purchased power and fuel; and (e) any other uncertainties the utility has identified."

The Companies have selected the Obsidian Plan as the Preferred Plan, and the Ward Plan as the Alternate Plan. The Action Plan period resources in each plan are listed below.

***Preferred Plan: Obsidian Plan.*** This plan, which meets the systemwide planning reserve margin (PRM), strives to meet the combined state RPS mandate and company credit commitments in every year, and targets the state's 2050 clean energy goal, includes:

1) 4,370 MW of new paired solar PV PPA projects by 2031 as presented in the Renewables Section of the Supply Plan
2) 5,405 MW of new paired and standalone BESS PPA projects by 2031 as presented in the Renewables Section of the Supply Plan
3) 180 MW of new geothermal PPA projects by 2031 as presented in the Renewables Section of the Supply Plan
4) The following new thermal resources as presented in the Generation Section of the Supply Plan, stated with nominal ratings
    a) Fort Churchill Additions 1 Project – 401 MW new simple-cycle aeroderivative gas turbines at the Fort Churchill Generation Station with an in-service date of June 2030
    b) Fort Churchill Additions 2 Project – 401 MW new simple-cycle aeroderivative gas turbines at the Fort Churchill Generation Station with an in-service date of June 2031
    c) Fort Churchill Additions 3 Project – 421 MW new simple-cycle frame gas turbines at the Fort Churchill Generation Station with an in-service date of June 2032
5) Transmission projects associated with the renewable, storage, and thermal projects and required to meet customers' needs as presented in the Transmission Plan.

***Alternate Plan: Ward Plan.*** This plan, which meets the systemwide PRM, strives to meet the combined state RPS mandate and company credit commitments in every year, and targets the state's 2050 clean energy goal, includes:

1) The same renewable and storage resources as the Preferred Plan
2) The following new thermal resources as presented in the Generation Section of the Supply Plan, stated with nominal ratings
    a) 601 MW new simple-cycle aeroderivative gas turbines at the Fort Churchill Generation Station with an in-service date of June 2030
    b) 421 MW new simple-cycle frame gas turbines at the Fort Churchill Generation Station with an in-service date of June 2031
    c) 421 MW new simple-cycle frame gas turbines at the Fort Churchill Generation Station with an in-service date of June 2032
3) Transmission projects associated with the renewable, storage, and thermal projects and required to meet customers' needs as presented in the Transmission Plan

NV Energy selected the Obsidian Plan as its Preferred Plan and the Ward Plan as its Alternate Plan. Both plans bolster clean energy generation in the state by adding the same portfolio of new solar, geothermal and BESS projects. The Obsidian Plan employs a moderate approach to thermal project additions, adding projects to serve the growing load but also leaving room to pivot in future filings as the load develops, technology advances, the economic environment changes, and federal

and state policy evolve. The peaking turbine projects in this plan are largely smaller models and add less total thermal capacity than the alternative plans. The Obsidian Plan also attempts to mitigate the emerging execution risk inherent in reliance on 2031 Frame combustion turbines ("CTs").

The Obsidian plan has the least capital commitment of the alternative plans. While it has the third lowest *total* Present Worth of Revenue Requirement ("PWRR") and Present Worth of Societal Costs ("PWSC") of the alternative plans, it has the lowest *capital cost* PWRR in the 5-year horizon. Of the four viable plans (excluding the nonviable Low Carbon Plan), Obsidian has the lowest *capital cost* PWRR in the 10-year horizon as well.

The Ward Plan has the second lowest total PWRR in the 5-, 10-, 20-, and 24-year study horizons and the second lowest PWSC. It has a lower open position in 2030 than the Obsidian, mitigating the perpetual risk of renewable resource failures and cancellations, but does not avoid the material execution risk of Frame CTs in 2031. It provides somewhat less flexibility to pivot in future filings than the Obsidian Plan.

Figure S-16 shows the projected loads and resources ("L&R Tables") under the Preferred Plan, assuming base load conditions. The Companies also developed high and low load sensitivities around the base load; the L&R Tables are presented in Technical Appendices.

# FIGURE S-16
# NV ENERGY PREFERRED PLAN LOADS AND RESOURCES TABLE

| | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Gross Peak | 9,330 | 9,886 | 10,807 | 11,521 | 12,470 | 12,997 | 13,130 | 13,915 | 14,395 | 14,834 | 15,320 | 15,589 | 15,651 | 16,491 | 16,810 | 17,163 | 17,613 | 17,851 | 18,355 | 18,727 |
| DSM Energy Efficiency Savings | 146 | 181 | 213 | 242 | 248 | 295 | 294 | 344 | 338 | 356 | 362 | 367 | 368 | 368 | 368 | 368 | 368 | 368 | 368 | 368 |
| DR Energy Efficiency Savings | 28 | 29 | 31 | 33 | 18 | 35 | 17 | 36 | 137 | 139 | 143 | 145 | 20 | 155 | 159 | 24 | 165 | 167 | 174 | 178 |
| Private Generation | 42 | 47 | 51 | 54 | 20 | 60 | 21 | 69 | 24 | 25 | 25 | 26 | 27 | 27 | 30 | 32 | 31 | 32 | 31 | 34 |
| Forecast System Peak | 9,114 | 9,629 | 10,511 | 11,192 | 12,183 | 12,607 | 12,798 | 13,466 | 13,897 | 14,314 | 14,790 | 15,051 | 15,237 | 15,941 | 16,253 | 16,740 | 17,049 | 17,285 | 17,782 | 18,148 |
| Sales Obligations | | | | | | | | | | | | | | | | | | | | |
| **NET System Peak** | 9,114 | 9,629 | 10,511 | 11,192 | 12,183 | 12,607 | 12,798 | 13,466 | 13,897 | 14,314 | 14,790 | 15,051 | 15,237 | 15,941 | 16,253 | 16,740 | 17,049 | 17,285 | 17,782 | 18,148 |
| Planning Reserves (12.5%) | 1,139 | 1,204 | 1,314 | 1,399 | 1,523 | 1,576 | 1,600 | 1,683 | 1,737 | 1,789 | 1,849 | 1,881 | 1,905 | 1,993 | 2,032 | 2,092 | 2,131 | 2,161 | 2,223 | 2,268 |
| **REQUIRED RESOURCES** | 10,253 | 10,833 | 11,825 | 12,591 | 13,706 | 14,183 | 14,398 | 15,150 | 15,634 | 16,103 | 16,639 | 16,932 | 17,141 | 17,934 | 18,284 | 18,832 | 19,180 | 19,445 | 20,005 | 20,416 |
| OATT Reserves | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 | 90 |
| **AVAILABLE RESOURCES** | 8,569 | 10,266 | 10,864 | 11,871 | 13,217 | 13,683 | 14,019 | 14,650 | 15,134 | 15,603 | 16,431 | 16,432 | 16,641 | 17,462 | 17,954 | 18,332 | 18,680 | 18,945 | 19,748 | 20,067 |
| OPEN Position | 1,684 | 567 | 962 | 720 | 490 | 500 | 379 | 500 | 500 | 500 | 208 | 500 | 500 | 471 | 330 | 500 | 500 | 500 | 257 | 349 |
| OPEN/(LONG) Position | 1,684 | 567 | 962 | 720 | 490 | 500 | 379 | 500 | 500 | 500 | 208 | 500 | 500 | 471 | 330 | 500 | 500 | 500 | 257 | 349 |
| | | | | | | | | | | | | | | | | | | | | |
| Sum of L&R MW | | | | | | | | | | | | | | | | | | | | |
| | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** | **2036** | **2037** | **2038** | **2039** | **2040** | **2041** | **2042** | **2043** | **2044** | **2045** | **2046** |
| **Owned Total** | **6,889** | **7,244** | **7,175** | **7,095** | **7,003** | **7,013** | **7,012** | **7,011** | **7,010** | **6,961** | **6,960** | **6,959** | **6,692** | **6,689** | **6,674** | **6,463** | **6,451** | **6,150** | **5,818** | **5,698** |
| NVE.Owned.Gas.CC-Int | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 726 | 537 | 353 | 353 |
| NVE.Owned.Gas.CT | 1,531 | 1,914 | 1,914 | 1,914 | 1,914 | 1,914 | 1,914 | 1,914 | 1,914 | 1,867 | 1,867 | 1,867 | 1,867 | 1,867 | 1,867 | 1,668 | 1,668 | 1,668 | 1,544 | 1,544 |
| NVE.Owned.Renewable.PV | 62 | 77 | 78 | 68 | 92 | 89 | 67 | 67 | 62 | 57 | 57 | 57 | 50 | 50 | 45 | 39 | 39 | 35 | 33 | 34 |
| NVE.Owned.Renewable.WH | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | - | - | - | - | - | - |
| NVE.Owned.Gas.CC | 3,442 | 3,442 | 3,453 | 3,453 | 3,465 | 3,477 | 3,477 | 3,477 | 3,477 | 3,477 | 3,477 | 3,477 | 3,477 | 3,477 | 3,477 | 3,477 | 3,477 | 3,477 | 3,477 | 3,477 |
| NVE.Owned.Diesel.GEN | 4 | 4 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| NVE.Owned.Gas.Steamer | 506 | 506 | 506 | 506 | 506 | 506 | 506 | 506 | 506 | 506 | 506 | 506 | 243 | 243 | 243 | 243 | 243 | 243 | 243 | 243 |
| NVE.Owned.Storage.BESS-4 | 353 | 335 | 285 | 242 | 159 | 159 | 176 | 174 | 176 | 178 | 176 | 175 | 178 | 176 | 173 | 170 | 164 | 139 | 123 | 4 |
| NVE.Owned.Storage.BESS-2 | 140 | 126 | 110 | 95 | 63 | 64 | 72 | 72 | 74 | 76 | 76 | 76 | 79 | 79 | 79 | 78 | 75 | - | - | - |
| PPA-Style.Owned.Storage.BESS-4 | 91 | 82 | 71 | 62 | 41 | 42 | 47 | 47 | 48 | 49 | 49 | 49 | 51 | 50 | 49 | 47 | 46 | 38 | 33 | 31 |
| PPA-Style.Owned.Renewable.PV | 28 | 27 | 27 | 24 | 32 | 31 | 23 | 23 | 21 | 20 | 20 | 20 | 17 | 17 | 16 | 15 | 14 | 13 | 12 | 13 |
| **Contracted Total** | **1,747** | **2,340** | **2,187** | **1,998** | **1,876** | **1,837** | **1,630** | **1,632** | **1,608** | **1,581** | **1,569** | **1,491** | **1,455** | **1,453** | **1,423** | **1,383** | **1,355** | **1,223** | **1,113** | **1,022** |
| PPA.Contracted.Diesel.GEN | 11 | 11 | 11 | 11 | 11 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| PPA.Contracted.Renewable.HYDRO | 168 | 165 | 161 | 161 | 161 | 161 | 161 | 161 | 161 | 161 | 161 | 161 | 161 | 161 | 160 | 160 | 160 | 160 | 160 | 160 |
| PPA.Contracted.Renewable.CSP | 13 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| PPA.Contracted.Renewable.GEO | 138 | 138 | 147 | 200 | 200 | 195 | 136 | 136 | 136 | 136 | 136 | 129 | 129 | 129 | 129 | 129 | 129 | 129 | 129 | 63 |
| PPA.Contracted.Renewable.LFG | 15 | 15 | 15 | 15 | 15 | 15 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| PPA.Contracted.Renewable.PV | 584 | 684 | 696 | 608 | 817 | 790 | 594 | 594 | 549 | 507 | 494 | 456 | 395 | 393 | 366 | 330 | 328 | 300 | 257 | 249 |
| PPA.Contracted.Storage.BESS-4 | 801 | 1,310 | 1,140 | 986 | 655 | 659 | 738 | 740 | 762 | 777 | 778 | 745 | 770 | 770 | 768 | 764 | 738 | 634 | 567 | 548 |
| PPA.Contracted.Renewable.WIND-NV | 17 | 17 | 17 | 17 | 17 | 17 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Proposed Total** | **24** | **772** | **1,592** | **2,868** | **3,771** | **4,192** | **4,237** | **4,237** | **4,258** | **4,259** | **4,260** | **4,272** | **4,288** | **4,287** | **4,227** | **4,170** | **4,062** | **3,667** | **3,412** | **3,324** |
| PPA.Proposed.Renewable.PV | | | | | | | | | | | | | | | | | | | | |
| 2028 - *VT_PV_624_Paired - South - NPC | - | - | 72 | 63 | 84 | 82 | 61 | 61 | 57 | 53 | 53 | 53 | 46 | 46 | 43 | 39 | 39 | 35 | 33 | 34 |
| 2030 - *MZ_PV_693_Paired - North - SPPC | - | - | - | 79 | 106 | 102 | 77 | 77 | 71 | 66 | 66 | 66 | 58 | 58 | 54 | 49 | 48 | 44 | 41 | 42 |
| 2028 - *CI_PV_803_Paired - North - SPPC | - | - | 63 | 55 | 74 | 71 | 54 | 54 | 50 | 46 | 46 | 46 | 40 | 40 | 38 | 34 | 34 | 31 | 29 | 30 |
| 2027 - *FT_PV_277_Paired - North - SPPC | - | 12 | 12 | 11 | 14 | 14 | 10 | 10 | 10 | 9 | 9 | 9 | 8 | 8 | 7 | 7 | 6 | 6 | 6 | 6 |
| 2028 - *AY_PV_590_Paired - North - SPPC | - | 22 | 22 | 20 | 26 | 26 | 19 | 19 | 18 | 16 | 16 | 17 | 14 | 14 | 13 | 12 | 12 | 11 | 10 | 11 |
| 2029 - *HS_PV_805_Paired - North - SPPC | - | - | - | 63 | 84 | 82 | 61 | 61 | 57 | 53 | 53 | 53 | 46 | 46 | 43 | 39 | 39 | 35 | 33 | 34 |
| 2030 - *VO_PV_999_Paired - South - NPC | - | - | - | - | 253 | 245 | 184 | 184 | 171 | 158 | 158 | 159 | 138 | 139 | 129 | 117 | 116 | 106 | 99 | 101 |
| 2030 - *OW_PV_900_Paired - South - NPC | - | - | - | - | 127 | 122 | 92 | 92 | 86 | 79 | 79 | 79 | 69 | 69 | 65 | 58 | 58 | 53 | 50 | 51 |
| 2028 - *SY_PV_111_Paired - South - NPC | - | 23 | 23 | 20 | 27 | 26 | 20 | 20 | 18 | 17 | 17 | 17 | 15 | 15 | 14 | 12 | 12 | 11 | 11 | 11 |
| 2029 - *KB_PV_134_Paired - North - SPPC | - | - | - | 55 | 74 | 71 | 54 | 54 | 50 | 46 | 46 | 46 | 40 | 40 | 38 | 34 | 34 | 31 | 29 | 30 |
| 2029 - *JA_PV_896_Paired - North - SPPC | - | - | - | 39 | 53 | 51 | 38 | 38 | 36 | 33 | 33 | 33 | 29 | 29 | 27 | 24 | 24 | 22 | 21 | 21 |
| PPA.Proposed.Storage.BESS-4 | | | | | | | | | | | | | | | | | | | | |
| 2028 - *VT_BESS_624_Paired - South - NPC | - | - | 285 | 246 | 164 | 167 | 187 | 187 | 193 | 197 | 197 | 198 | 205 | 205 | 204 | 203 | 196 | 168 | 151 | 146 |
| 2028 - *EG_BESS_655 - South - NPC | - | 82 | 71 | 62 | 41 | 42 | 47 | 47 | 48 | 49 | 49 | 49 | 51 | 51 | 51 | 51 | 49 | 42 | 38 | 36 |
| 2030 - *MZ_BESS_693_Paired - North - SPPC | - | - | - | 308 | 205 | 209 | 234 | 234 | 241 | 246 | 246 | 247 | 256 | 256 | 255 | 254 | 245 | 210 | 188 | 182 |
| 2028 - *CI_BESS_803_Paired - North - SPPC | - | - | 249 | 215 | 143 | 146 | 163 | 164 | 169 | 172 | 172 | 173 | 179 | 179 | 179 | 178 | 172 | 147 | 132 | 128 |
| 2027 - *FT_BESS_277_Paired - North - SPPC | - | 55 | 47 | 40 | 27 | 28 | 31 | 30 | 30 | 31 | 30 | 30 | 30 | 30 | 29 | 29 | 27 | 23 | 20 | 19 |
| 2027 - *UL_BESS_558 - South - NPC | - | 123 | 107 | 92 | 61 | 63 | 70 | 70 | 72 | 74 | 74 | 74 | 77 | 77 | 77 | 76 | 74 | 63 | 56 | 55 |
| 2027 - *XY_BESS_001 - North - SPPC | - | 61 | 53 | 46 | 31 | 31 | 35 | 35 | 36 | 37 | 37 | 37 | 38 | 38 | 38 | 38 | 37 | 32 | 28 | 27 |
| 2028 - *AY_BESS_590_Paired - North - SPPC | - | 102 | 86 | 72 | 46 | 47 | 51 | 50 | 51 | 52 | 51 | 51 | 52 | 52 | 51 | 50 | 48 | 41 | 36 | 35 |
| 2029 - *HS_BESS_805_Paired - North - SPPC | - | - | - | 246 | 164 | 167 | 187 | 187 | 193 | 197 | 197 | 198 | 205 | 205 | 204 | 203 | 196 | 168 | 151 | 146 |
| 2030 - *VO_BESS_999_Paired - South - NPC | - | - | - | - | 491 | 501 | 561 | 562 | 578 | 590 | 591 | 594 | 614 | 614 | 612 | 609 | 588 | 505 | 452 | 437 |
| 2028 - *AH_BESS_492 - North - SPPC | - | 164 | 142 | 123 | 82 | 83 | 93 | 94 | 96 | 98 | 98 | 99 | 102 | 102 | 102 | 101 | 98 | 84 | 75 | 73 |
| 2030 - *OW_BESS_900_Paired - South - NPC | - | - | - | - | 246 | 250 | 280 | 267 | 275 | 280 | 281 | 282 | 292 | 292 | 276 | 275 | 265 | 228 | 204 | 197 |
| 2028 - *SY_BESS_111_Paired - South - NPC | - | 105 | 91 | 79 | 52 | 53 | 60 | 60 | 62 | 63 | 63 | 63 | 65 | 65 | 65 | 65 | 63 | 54 | 48 | 47 |
| 2029 - *KB_BESS_134_Paired - North - SPPC | - | - | - | 215 | 143 | 146 | 163 | 164 | 169 | 172 | 172 | 173 | 179 | 179 | 179 | 178 | 172 | 147 | 132 | 128 |
| 2029 - *JA_BESS_896_Paired - North - SPPC | - | - | - | 154 | 102 | 104 | 117 | 117 | 120 | 123 | 123 | 124 | 128 | 128 | 128 | 127 | 123 | 105 | 94 | 91 |
| PPA.Proposed.Storage.BESS-8 | | | | | | | | | | | | | | | | | | | | |
| 2029 - *WX_BESS_777 - South - NPC | - | - | 245 | 222 | 143 | 147 | 170 | 171 | 177 | 183 | 183 | 183 | 195 | 195 | 195 | 200 | 180 | 155 | 138 | 128 |
| PPA.Proposed.Renewable.Geo | | | | | | | | | | | | | | | | | | | | |
| 2030 - *GG_Geo_007 - North - SPPC | - | - | - | - | 30 | 29 | 29 | 29 | 28 | 28 | 27 | 27 | 26 | 26 | 26 | 25 | 25 | 25 | 24 | - |
| 2027 - *GN_Geo_395 - North - SPPC | 24 | 24 | 23 | 22 | 22 | 21 | 20 | 19 | 19 | 18 | 17 | 17 | 16 | 16 | 15 | 15 | 14 | 14 | 13 | 13 |
| 2030 - *GW_Geo_021 - North - NPC | - | - | - | 9 | 9 | 9 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 2030 - *RT_Geo_404 - North - SPPC | - | - | - | - | 21 | 31 | 41 | 52 | 50 | 49 | 48 | 48 | 47 | 46 | 45 | 44 | 43 | 42 | 41 | 40 |
| NVE.Proposed.GAS.CT-Aero | | | | | | | | | | | | | | | | | | | | |
| 2030 - CT-Aero - FTC - North - SPPC | - | - | - | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 |
| 2031 - CT-Aero - FTC - North - SPPC | - | - | - | - | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 |
| NVE.Proposed.GAS.CT-Frame | | | | | | | | | | | | | | | | | | | | |
| 2032 - CT-Frame - FTC - North - SPPC | - | - | - | - | - | 402 | 402 | 402 | 402 | 402 | 402 | 402 | 402 | 402 | 402 | 402 | 402 | 402 | 402 | 402 |
| **Generic Placeholders Total** | - | - | - | - | **415** | **484** | **863** | **1,310** | **1,763** | **2,304** | **3,145** | **3,211** | **3,707** | **4,534** | **5,136** | **5,830** | **6,338** | **7,477** | **9,006** | **9,630** |
| PPA.Generic Placeholders.Storage.BESS-4 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1,171 | 1,730 | 2,017 |
| PPA.Generic Placeholders.Renewable.PV | - | - | - | - | 42 | 82 | 306 | 307 | 301 | 385 | 386 | 420 | 451 | 451 | 630 | 777 | 1,028 | 1,100 | 1,323 | 1,376 |
| PPA.Generic Placeholders.Renewable.Geo | - | - | - | - | 21 | 42 | 83 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 411 |
| PPA.Generic Placeholders.Renewable.WIND-NV | - | - | - | - | - | - | 47 | 91 | 131 | 168 | 204 | 235 | 262 | 284 | 305 | 327 | 345 | 364 | 382 | 400 |
| PPA.Generic Placeholders.Storage.BESS-10 | - | - | - | - | 352 | 361 | 425 | 426 | 442 | 459 | 460 | 461 | 496 | 496 | 496 | 619 | 858 | 736 | 660 | 600 |
| NVE.Generic Placeholders.Other.TBD_CT | - | - | - | - | - | - | - | 402 | 804 | 1,207 | 2,011 | 2,011 | 2,413 | 3,217 | 3,620 | 4,022 | 4,022 | 4,022 | 4,826 | 4,826 |
| NVE.Generic Placeholders.Other.TBD_CC-Large | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Named Placeholders Total** | - | - | - | - | **242** | **246** | **368** | **549** | **584** | **587** | **587** | **589** | **589** | **589** | **583** | **575** | **565** | **519** | **490** | **483** |
| PPA.Named Placeholders.Storage.BESS-4 | - | - | - | - | 242 | 246 | 276 | 277 | 285 | 290 | 291 | 292 | 302 | 302 | 301 | 300 | 289 | 249 | 222 | 215 |
| PPA.Named Placeholders.Renewable.PV | - | - | - | - | - | - | 92 | 92 | 86 | 79 | 79 | 79 | 69 | 69 | 65 | 58 | 58 | 53 | 50 | 51 |
| PPA.Named Placeholders.Renewable.WIND-ID | - | - | - | - | - | - | - | 180 | 214 | 218 | 218 | 218 | 218 | 218 | 218 | 218 | 218 | 218 | 218 | 218 |

The regulations governing integrated resource planning require that the Companies include in their triennial IRPs a 20-year plan to meet the transmission needs of native load customers[8] and service requests from third parties.[9] In order to meet increasing large customer needs, the transmission plan includes many new projects. Transmission projects driven by customers have controls in place at each phase, meant to reduce the risk to both the Companies and native load customers. These project controls include the customer providing security, construction deposits, reduction in service charges and customer's construction milestones.

The Companies are requesting Action Plan approval to begin network upgrades associated with transmission projects summarized in Figure S-17.

**FIGURE S-17**
**TRANSMISSION PROJECTS LIST SUMMARY**

| Project Name | Voltage | Cost ($Million) | In-Service Date |
|---|---|---|---|
| **Sapphire 230/120 kV substation** | **230/120 kV** | **$25.31** | **2028** |
| **230 kV HVD lines at Sapphire substation** | **230 kV** | **$10.37** | **2028** |
| **Connect Sapphire to Basin 230 kV line** | **230 kV** | **$3.70** | **2031** |
| **Add two (2) 230 kV HVD lines at Sapphire substation** | **230 kV** | **$9.40** | **2031** |
| **Connect Sapphire to Opal 230 kV line** | **230 kV** | **$4.70** | **2031** |
| **Basin 525/230 kV 1500 MVA transformer substation** | **525/230 kV** | **$114.50** | **2031** |
| **Basin second 525/230 kV 1500 MVA transformer** | **525/230 kV** | **$49.10** | **2031** |
| **Sand Dune 230 kV switching station with 230 kV HVD lines** | **230 kV** | **$38.50** | **2029** |
| **Add 230 kV HVD lines at Sand Dune** | **230 kV** | **$32.00** | **2029** |

[8] The term "Native Load Customer" comes from regulations established by the FERC creating and maintain their open access transmission policies. Nevada Power and Sierra operate a single Balancing Area Authority ("BAA"), which is responsible for serving both native load and transmission-only customers. Native load customers are the bundled retail customers of both Nevada Power and Sierra. Native load customers do not plan for and purchase transmission access directly from the BAA. Instead, Nevada Power and Sierra plan for and reserve transmission access on their behalf, consistent with the FERC's open access transmission policies, and pursuant to the Companies' Open Access Transmission Tariff or "OATT".
[9] *See* NAC § 704.9385(3).

| | | | |
|---|---|---|---|
| **Connect Sand Dune to Navigator 230 kV line** | **230 kV** | **$4.70** | **2031** |
| **New Opal 230 kV switching station with 230 kV HVD lines, 230 kV line to Sapphire and HGIII** | **230 kV** | **$61.80** | **2031** |
| **New Navigator switching station with 230 kV HVD lines, 230 kV line to HGIII and Sand Dune** | **230 kV** | **$36.50** | **2031** |
| **Connect HGIII to Opal, 230 kV line** | **230 kV** | **$65.00** | **2031** |
| **Connect HGIII to Navigator 230 kV line terminal and add 525/230 kV 600 MVA transformer at HGIII** | **525/230 kV** | **$65.00** | **2031** |
| **Two Chukar 345/120 kV transformers** | **345/120 kV** | **$83.90** | **2029** |
| **Viking switching station to connect 345 kV HVD lines, connects to Lantern-Comstock 345 kV line** | **345 kV** | **$16.80** | **2030** |
| **Vaquero switching station to connect 345 kV HVD lines, add two (2) 345/120 kV 280 MVA transformers, connects to Lantern-Comstock 345 kV line, with 120 kV HVD lines** | **345/120 kV** | **$62.00** | **2031** |
| **HVD line terminals for Rule 9 customer at East Tracy** | **120 kV** | **$4.30** | **2031** |
| **Petroglyph switching station, connects to West Tracy - Comstock Meadows 345 kV line, with new 345 kV HVD lines** | **345 kV** | **$28.80** | **2029** |
| **Mallard 525/345 kV substation, connects to Mackay-Goose 525 kV line, with HVD lines** | **525/345 kV** | **$270.00** | **2032** |
| **Goose 525/345 kV substation, add two (2) 525/345 kV 1500 MVA transformer banks, with new 345 HVD lines** | **525/345 kV** | **$210.00** | **2032** |
| **Three Mackay 525/345 kV 600 MVA transformers** | **525/345 kV** | **$170.00** | **2032** |
| **Walker River-Goose-Mackay-Walker River 525 kV transmission lines** | **525 kV** | **$405.00** | **2032** |
| **Spring Canyon 230/12 kV substation with three (3) 37 MVA transformers, connects to Greenway-Mead 230 kV line** | **230/12 kV** | **$45.60** | **2028** |
| **Scorpion 230 kV switching station, connects to Arden-Mead 230 kV line, with HVD lines** | **230 kV** | **$43.00** | **2030** |

| | | | |
|---|---|---|---|
| **Ft Sage 345/69 kV transformer** | **345/69 kV** | **$6.90** | **2028** |
| **Northwest 230 kV line terminal** | **230 kV** | **$0**[10] | **2028** |
| **NSO-Magnolia 230 kV line** | **230 kV** | **$67.99** | **2035** |
| **Onyx 230/69 kV substation** | **230/69 kV** | **$50.00** | **2032** |
| **Harry Allen reactors** | **230 kV** | **$10.87** | **2028** |
| **Coyote Creek 345 kV breakers** | **345 kV** | **$3.40** | **2031** |
| **Equestrian 230 kV breaker** | **230 kV** | **$6.94** | **2030** |
| **Northwest 525/230 kV transformer #7** | **525/230 kV** | **$63.50** | **2030** |
| **East Tracy-West Tracy 345 kV #2** | **345 kV** | **$15.98** | **2029** |
| **East Tracy-West Tracy 345 kV #1 reconductor** | **345 kV** | **$2.00** | **2029** |
| **Replace East Tracy 345/120 kV transformer #1 with 400 MVA** | **345/120 kV** | **$20.00** | **2029** |
| **Replace Reno Substation switch #1101 and #1113** | **120 kV** | **$0.20** | **2029** |
| **Reconductor 120 kV line #103** | **120 kV** | **$5.00** | **2029** |
| **Frontier-Lander 230 kV line** | **230 kV** | **$30.00** | **2030** |
| **Brooks 230/138 kV substation with two (2) 400 MVA transformers** | **230/138 kV** | **$76.00** | **2030** |
| **Brooks 138/12 kV 33 MVA transformers, construct 12 kV get aways** | **138/12 kV** | **$25.00** | **2030** |
| **Coyote Creek-Falcon 345 kV line** | **345 kV** | **$66.00** | **2030** |
| **Olinghouse-Chukar 345 kV line** | **345 kV** | **$38.00** | **2030** |
| **Third 345 kV PST and third 525/345 kV transformers at Robinson Summit substation** | **525/345 kV** | **$55.00** | **2030** |

[10] Customer-funded.

| | | | |
|---|---|---|---|
| **Esmeralda-Millers 230 kV line** | **230 kV** | **$120.00** | **2030** |
| **Interconnection of Big Smokey lead line at Millers** | **120 kV** | **$20.00** | **2030** |
| **120 kV line terminal at Wassuk substation for lead line for Mason** | **120 kV** | **$2.00** | **2030** |
| **Candeleria switching station with 120 kV lead line position for Excelsior Geothermal project** | **120 kV** | **$30.00** | **2030** |
| **#124 line clearance mitigations** | **120 kV** | **$0.50** | **2030** |
| **Walker River 120 kV line terminal** | **120 kV** | **$2.00** | **2030** |
| **Walker River 345/230 kV transformer #3** | **345/230 kV** | **$25.00** | **2030** |
| **Walker River 230 kV line terminal** | **230 kV** | **$3.00** | **2030** |
| **Walker River 345 kV line terminal** | **345 kV** | **$3.00** | **2030** |
| **Miller1238 kV line terminal** | **138 kV** | **$0.60** | **2030** |
| **Apex 525 kV line terminal** | **525 kV** | **$4.00** | **2030** |
| **Gonder 230 kV line Terminal** | **230 kV** | **$1.80** | **2030** |
| **Gonder generator run back RAS for loss Gonder 345 kV connection to Robinson Summit** | **230 kV** | **$1.10** | **2030** |
| **Mira Loma 120 kV line terminal** | **120 kV** | **$4.20** | **2030** |
| **Reconductor #129 120 kV line** | **120 kV** | **$2.80** | **2030** |
| **Uprate Iron Mountain-Lorenzi 138 kV line** | **138 kV** | **$0.30** | **2030** |
| **Resolve clearance on #3420 & change size of conductor Lantern-Comstock Meadows 345 kV line** | **345 kV** | **$5.80** | **2030** |
| **North Valmy 345 kV line terminal** | **345 kV** | **$2.60** | **2030** |

| | | | |
|---|---|---|---|
| **Grayskull 525/345 kV substation, with two (2) 1500 MVA transformers, Grayskull-Walker River 525 kV line** | **525 kV** | **$479.50** | **2030** |
| **Walker River 345 kV line terminal** | **345 kV** | **$5.00** | **2030** |
| **Valmy geothermal portfolio network upgrades. Rebuild #118 Eagle-NGPP, reconductor #3422 between East Tracy-Lantern, add PST at Oreanna** | **120 kV** | **$89.80** | **2030** |
| **POI substation for Rose of Snowville** | **120 kV** | **$31.00** | **2030** |
| **POI 120 kV line terminal** | **120 kV** | **$1.50** | **2030** |
| **POI substation for Pumpernickel** | **120 kV** | **$22.80** | **2030** |
| **Bald Mountain 120 kV line terminal** | **120 kV** | **$5.30** | **2030** |

## SECTION VI – SUMMARY OF THE RENEWABLE ENERGY PLAN: NAC § 704.9215(2)(e)

***Existing Fleet of Renewable Resources.*** Nevada is fortunate to have significant renewable resources throughout the state, including some of the greatest solar and geothermal generation potential in the country. The Companies have built a diverse and robust portfolio of renewable projects through both long-term PPAs and utility-owned renewable projects.

As of April 30, 2026, Nevada Power had approximately 2,723 MW of contracted and 165 MW of owned renewable generating resources providing renewable energy to meet the energy needs of its customers. In addition, Nevada Power ended March 2026 with the following three solar PV and BESS projects under development: Sierra Solar, Dry Lake East, and Libra – pending final allocation of the Libra project between Nevada Power and Sierra. Sierra had approximately 945 MW of renewable contracted generating resources and approximately 20 MW of Company-owned generating resources operating and delivering renewable energy to meet the energy needs of its customers. In addition to the aforementioned Sierra Solar PV and BESS project, Sierra ended March 2026 with seven geothermal projects in various stages of development.

Figures S-18 and S-19 list the renewable energy resources under long-term contract with Nevada Power and Sierra.

# FIGURE S-18
# NEVADA POWER LONG-TERM PURCHASE POWER AGREEMENTS

| Contract Name | Docket Number | Contract Type | Capacity (MW) | Commercial Operation Date | Termination Date | BESS Termination Date |
|---|---|---|---|---|---|---|
| **Renewable Purchase Agreements** | | | | | | |
| **PPAs (Commercial)** | | | | | | |
| ACE Searchlight[QF] | 09-08020 | Solar[S] | 17.5 | 12/16/14 | 12/31/2034 | |
| APEX Landfill[QF] | 09-08020 | Methane | 12.0 | 03/01/12 | 12/31/2032 | |
| Boulder Solar I[EWG] | 15-07003 | Solar[S] | 100.0 | 12/09/16 | 12/31/2036 | |
| Colorado River Commission-Hoover | - | Hydro | 237.6 | 10/01/17 | 09/30/2067 | |
| Copper Mountain 5[EWG] | 18-06003 | Solar[S] | 250.0 | 07/23/21 | 12/31/2046 | |
| Desert Peak 2[QF] | 02-11040 | Geothermal | 25.0 | 04/17/07 | 12/31/2027 | |
| Eagle Shadow Mountain[EWG] | 18-06003 | Solar[S] | 300.0 | 05/10/23 | 12/31/2048 | |
| FRV Spectrum[QF] | 11-03014 | Solar[S] | 30.0 | 09/23/13 | 12/31/2038 | |
| Gemini Solar[EWG] | 19-06039 | Solar[S,X=380 (3.7 hrs) 3] | 690.0 | 03/25/24 | 12/31/2049 | 12/31/2049 |
| Jersey Valley[QF] | 06-10021 | Geothermal | 22.5 | 08/30/11 | 12/31/2031 | |
| McGinness Hills[QF] | 10-02009 | Geothermal | 96.0 | 06/20/12 | 12/31/2032 | |
| Moapa (Arrow Canyon) Solar[EWG] | 19-06039 | Solar[S,X=74 (5 hrs) 3] | 200.0 | 12/08/23 | 12/31/2048 | 12/31/2048 |
| Mountain View[EWG] | 11-03014 | Solar[S] | 20.0 | 01/05/14 | 12/31/2039 | |
| Nevada Solar One (NPC)[QF] | 02-11040 | Solar[T,X] | 46.9 | 06/27/07 | 12/31/2027 | |
| NGP Blue Mountain[QF] | 06-10021 | Geothermal | 49.5 | 11/20/09 | 12/31/2029 | |
| RV Apex[QF] | 10-02009 | Solar[S] | 20.0 | 07/21/12 | 12/31/2037 | |
| Salt Wells[QF] | 07-02015 | Geothermal | 23.6 | 09/18/09 | 12/31/2029 | |
| Silver State[EWG] | 10-03022 | Solar[F] | 52.0 | 04/25/12 | 12/31/2037 | |
| Spring Valley[EWG] | 10-02009 | Wind | 151.8 | 08/16/12 | 12/31/2032 | |
| Stillwater Geothermal[1,QF] | 07-02015 | Geothermal | 47.2 | 10/10/09 | 12/31/2029[4] | |
| Stillwater PV[1,QF] | 07-02015 | Solar[F] | 22.0 | 03/05/12 | 12/31/2029[4] | |
| Switch Station 1[EWG] | 15-07003 | Solar[S] | 100.0 | 08/08/17 | 12/31/2037 | |
| Switch Station 2 (NPC)[EWG] | 15-11029 | Solar[S] | 0.0 | 10/11/17 | 12/31/2037 | |
| Techren I[EWG] | 16-08026 | Solar[S] | 100.0 | 03/11/19 | 12/31/2044 | |
| Techren III[QF] | 17-11004 | Solar[S] | 25.0 | 10/07/20 | 12/31/2045 | |
| Techren V[EWG] | 18-06003 | Solar[S] | 50.0 | 12/31/20 | 12/31/2045 | |
| Tuscarora[QF] | 10-03022 | Geothermal | 32.0 | 01/11/12 | 12/31/2032 | |
| WM Renewable Energy-Lockwood[QF] | 10-03022 | Methane | 3.2 | 04/01/12 | 12/31/2032 | |
| | | **Total** | **2723.8** | | | |
| **PC Purchase Agreements** | | | | | | |
| Sierra Pacific Power | 09-08018 & 09-08020 | Geothermal | 2.3 | 10/30/09 | 12/31/2028 | |
| Nellis I (Solar Star)[QF] | 07-01035 | Solar | 13.2 | 12/15/07 | 12/31/2027 | |
| SunPower (LVVWD) | 04-11033 | Solar | 3.0 | 04/20/06 | 12/31/2026 | |
| | | **Total** | **18.5** | | | |
| **PPAs (Pre-Commercial)[2]** | | | | **Estimated COD** | **Termination Date** | **BESS Termination Date** |
| Dry Lake East | 24-05041 | Solar[S,X=200(4hrs)] | 200.0 | 12/01/26 | 12/31/2051 | 12/31/2046 |
| Libra Solar | 24-05041 | Solar[S,X=700(4hrs)] | 700.0 | 12/01/27 | 12/31/2052 | 12/31/2047 |
| | | **Total** | **900.0** | | | |
| **Non-Renewable Purchase Agreements** | | | | | | |
| **Renewable and Non-Renewable Sales** | | | | | | |
| Switch NGR (Switch Station 1) | 15-08005 | NGR Agreement (Sale of PCs) | 100.0 | 08/08/17 | 12/31/2037 | |
| Switch NGR-NPC (Switch Station 2) | 15-11028 | NGR Agreement (Sale of PCs) | 0.0 | 10/11/17 | 12/31/2037 | |

Notes:
1. The geothermal and solar facilities are combined into one PPA.
2. Facilities are either under development or construction (the dates shown are expected dates).
3. Storage reflects current MW based on annual storage capacity test
4. NPC has an option to extend the Stillwater Geothermal/Solar PPA for a period of 3, 4 or 5 years upon the termination date.
QF=Qualifying Facility, EWG=Exempt Wholesale Generator, S=Single Axis Tracking, T=Solar Thermal (Tracking), F=Fixed Tilt, X=Storage

# FIGURE S-19
# SIERRA'S LONG-TERM PURCHASE POWER AGREEMENTS

| Contract Name | Docket Number | Contract Type | Capacity (MW) | Commercial Operation Date | Termination Date | BESS Termination Date |
|---|---|---|---|---|---|---|
| **Renewable Energy** | | | | | | |
| **PPAs (Commercial)** | | | | | | |
| Battle Mountain[EWG] | 18-06003 | Solar[5,X=24.2MW (4 hrs) 6] | 101.0 | 6/23/2021 | 12/31/2046 | 12/31/2031 |
| Boulder Solar II[EWG] | 15-11029 | Solar[5] | 50.0 | 1/27/2017 | 12/31/2037 | |
| Burdette[QF] | 04-08004 | Geothermal | 26.0 | 2/28/2006 | 12/31/2026 | |
| Dodge Flat[EWG] | 18-06003 | Solar[5,X=50MW (4 hrs) 6] | 200.0 | 3/2/2022 | 12/31/2047 | 12/31/2037 |
| Fish Springs Ranch[EWG] | 18-06003 | Solar[5,X=24.91MW (4 hrs) 6] | 100.0 | 3/15/2022 | 12/31/2047 | 12/31/2037 |
| Galena 3[QF] | 06-05040 | Geothermal | 26.5 | 2/21/2008 | 12/31/2028 | |
| Hooper[1,QF] | QF-Legacy | Hydro | 0.75 | 6/23/2016 | 12/31/2040 | |
| Kingston[1] | - | Hydro | 0.175 | 9/19/2011 | 12/31/2040 | |
| Mill Creek[1] | - | Hydro | 0.037 | 9/1/2011 | 12/31/2040 | |
| Nevada Solar One (SPPC)[QF] | 02-12039 | Solar[T] | 22.1 | 6/27/2007 | 12/31/2027 | |
| North Valley[QF] | 22-03024 | Geothermal | 25 | 4/26/2023 | 12/31/2048 | |
| OWGP Beowawe[QF] | 22-11032 | Geothermal | 20.0 | 1/10/2025 | 12/31/2053 | |
| RO Ranch[1,2] | - | Hydro | 0 | 3/15/2011 | 12/31/2040 | |
| Switch Station 2 (SPPC)[EWG] | 15-11029 | Solar[5] | 79.0 | 10/11/2017 | 12/31/2037 | |
| Techren II[EWG] | 17-02007 | Solar[5] | 200.0 | 10/4/2019 | 12/31/2044 | |
| Techren IV[QF] | 17-11003 | Solar[5] | 25.0 | 10/7/2020 | 12/31/2045 | |
| TMWA Fleish | 07-01036 | Hydro | 2.4 | 5/16/2008 | 6/1/2028 | |
| TMWA Verdi | 07-01036 | Hydro | 2.4 | 5/15/2009 | 6/1/2029 | |
| TMWA Washoe | 07-01036 | Hydro | 2.5 | 7/25/2008 | 6/1/2028 | |
| Turquoise[EWG] | 17-11003 | Solar[F] | 50.0 | 12/4/2020 | 12/31/2045 | |
| USG San Emidio[QF] | 11-08010 | Geothermal | 11.75 | 5/25/2012 | 12/31/2037 | |
| | | Total | 944.6 | | | |
| **PC Purchase Agreement** | | | | | | |
| TMWRF | 06-04030 | Methane | 0.8 | 9/9/2005 | 9/1/2026 | |
| **PPAs (Pre-Commercial)[3]** | | | | Estimated COD | Termination Date | |
| Ormat Western Geothermal Portfolio (OWGP)[3] | | | | | | |
| OWGP Pinto[QF] | 22-11032 | Geothermal | 15.0 | 1/1/2027 | 12/31/2053 | |
| OWGP Galena 1[QF] | 22-11032 | Geothermal | 15.0 | 2/1/2027 | 12/31/2053 | |
| OWGP Desert Peak 2[QF] | 22-11032 | Geothermal | 10.0 | 2/1/2028 | 12/31/2053 | |
| OWGP Lone Mountain[QF] | 22-11032 | Geothermal | 15.0 | 10/1/2028 | 12/31/2053 | |
| OWGP Galena 3[QF] | 22-11032 | Geothermal | 15.0 | 1/1/2029 | 12/31/2053 | |
| OWGP TBD | 22-11032 | Geothermal | 30.0 | TBD | 12/31/2053 | |
| Corsac Generating Station 2 LLC | 24-05041 | Geothermal | 115.0 | 2/1/2030 | 12/31/2045 | |
| | | Total | 215.0 | | | |
| **Storage Only (Pre-Commercial)[3]** | | | | | | |
| Dodge Flat Energy Storage | 25-10028 | Solar & Grid Tied BESS [150 MW (4 hrs)] | 0.0 | 7/1/2027 | | 12/31/2047 |
| | | Total | 0.0 | | | |
| **Non-Renewable Purchase Agreements** | | | | | | |
| Liberty (CalPeco) EBSA[7] | 09-12002 & 10-07003 | Diesel | 12.0 | 1/1/2011 | 12/31/2031 | |
| | | Total | 12.0 | | | |
| **Renewable & Non-Renewable Sales Agreements** | | | | | | |
| Liberty (CalPeco) | - | Full Requirements (Capacity/Energy/PCs) | See Note 4 | 12/30/2020 | 5/31/2027 | |
| NPC-SPPC | 09-08018 & 09-08020 | Sale of PCs (Geothermal) | 2.3 | 10/30/2009 | 12/31/2028 | |
| Apple NGR (Fort Churchill Solar) | 13-07002 | NGR Agreement (Sale of PCs) | 19.5 | 8/5/2015 | 8/4/2040 | |
| Apple NGR (Boulder Solar II) | 15-11025 | NGR Agreement (Sale of PCs) | 50.0 | 1/27/2017 | 12/31/2037 | |
| Switch NGR-SPPC (Switch Station 2) | 15-11025 | NGR Agreement (Sale of PCs) | 79.0 | 10/11/2017 | 12/31/2037 | |
| Apple NGR (Techren II) | 17-02008 | NGR Agreement (Sale of PCs) | 200.0 | 10/4/2019 | 6/20/2044 | |
| Apple NGR (Turquoise) | 17-11002 | NGR Agreement (Sale of PCs) | 50.0 | 12/4/2020 | 4/30/2045 | |

Notes:
1. The illustrative termination date shown is subject to certain conditions, which may result in termination before or after December 31, 2040.
2. RO Ranch Hydro facility is shut down indefinitely (the PPA is still active).
3. Facilities are either under development or construction (the dates shown are expected dates).
4. The current monthly contract demand ranges from approximately 70 MW (June) to 140 MW (December). Contract extension pending FERC approval.
5. Portfolio consists of multiple facilites under one Power Purchase Agreement
6. Storage reflects current MW based on annual storage capacity test
7. Emergency backup service agreement for King's Beach Diesels

QF=Qualifying Facility, EWG=Exempt Wholesale Generator, S=Single Axis Tracking, T=Solar Thermal (Tracking), F=Fixed Tilt, X=Storage

***RPS Compliance Outlooks.*** Nevada's RPS is set forth at NRS § 704.7821 and is based on a percentage of the total amount of electricity sold to retail customers in Nevada. The RPS is currently set at 34 percent, meaning that not less than 34 percent of the energy Nevada Power and Sierra sell to their retail customers in Nevada must be matched by portfolio energy credits ("PCs") generated, acquired, or served from qualified renewable systems and sources. The RPS increases to 42 percent in 2027, 50 percent in 2030 and for each calendar year thereafter.

In their most recent annual RPS compliance filing, Docket No. 26-04023, Nevada Power and Sierra both exceeded their respective 2025 RPS credit requirements of 34 percent. Nevada Power ended 2025 at 44.6 percent, Sierra at 54.7 percent.

***Nevada Power RPS Compliance.*** With the approval of the proposed projects in this filing, Nevada Power's RPS compliance outlook is forecasted to be non-compliant in 2027 through the end of the study period. For several reasons, this Nevada Power RPS compliance outlook is different from those stated in the 2024 Joint IRP and the Portfolio Standard Annual Report for Compliance Year 2025 filed on April 15, 2026, in Docket No. 26-04023. First, the projected high retail load growth coupled with the large RPS compliance tier increase in 2027 to 42 percent, magnify the goal and compound the challenge to meet RPS compliance. Nevada Power's current retail load outlook in this IRP filing is higher than that of the previously approved plan from the 2024 Joint IRP and in the year when the RPS increases to 42 percent. Because the RPS credit requirement is tied directly to retail sales, the combined change significantly increases Nevada Power's forecasted RPS credit requirement. Second, the limited available land for development, multiyear project permitting timelines, and lack of available transmission capacity are key constraints in the renewable project pipeline. Third, 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, exogenous to the project, that may not be knowable or cannot be easily mitigated, even with diligent planning. For example, the Boulder Solar III project approved in Docket No. 24-05041 has experienced challenges in its development due to increased costs, driven primarily by external factors and permitting delays. The developer missed a critical project milestone and subsequently, on March 20, 2026, terminated the PPA.

***Sierra RPS Compliance***. With the approval of the proposed projects in this filing, Sierra is projected to be non-compliant in 2027, return to compliance in 2028 through 2030, become non-compliant in 2031 through 2032, and return to compliance in 2033 through the end of the 24-year study period (2027-2050). Compliance in 2028 and 2029 is partly attributable to accounting for the output from Libra in Sierra's outlook as opposed to Nevada Power's outlook. This is different from the 2024 IRP's outlook in Docket No. 24-05041 as well as the Portfolio Standard Annual Report for Compliance Year 2025 filed on April 15, 2026, in Docket No. 26-04023, for several reasons. First, the projected high retail load growth coupled with the large RPS compliance tier

increase in 2027 to 42 percent, magnify the goal and compound the challenge to meet RPS compliance. Under the current load forecast, Sierra's current retail load outlook is higher than that of the previously approved plan from the 2024 Joint IRP and in the year when the RPS increases to 42 percent. Because the RPS credit requirement is tied directly to retail sales, the combined change increases Sierra's forecasted RPS credit requirement. Included in the increased forecast of Sierra's load is the planned extension of the Liberty contract through December 31, 2027, which also provides PCs to the utility. Finally, the Sierra's Utility Owned Community Solar ("UOCS") and Solar for All ("S4A") projects proposed in Docket No. 24-05041 were not approved, resulting in the loss of a planned 6,312 PCs.

Second, Sierra's RPS compliance challenges are also a result of PPA cancellations by developers. As discussed in the First Amendment to the 2024 Joint IRP, Ormat has provided notice to the Companies that two of its portfolio PPAs, North Valley 2 and Gerlach, have been cancelled, and the Lone Mountain PPA COD has been delayed from January 2026 to October 2028. Additionally, Liberty has notified the Companies that it has placed its Luning Expansion Project on hold indefinitely, which would have provided Liberty with PCs and therefore reduced Sierra's PC transfer obligation to Liberty under the requirements of the service agreement associated with Liberty's Luning Expansion Project. The energy and credits from the various facilities were to be assigned to Sierra; thus, the cancellation of those PPAs impacts Sierra's RPS compliance and capacity. While every PPA is entered into with the expectation of success, events can and do happen that make once-viable PPAs unviable. Similar to the external forces impacting Nevada Power's PPA projects explained above, Sierra's PPA projects are also subject to various independent external forces, exogenous to the project, that may not be knowable or cannot be easily mitigated, even with diligent planning. The primary driver for the latest wave of cancelations was cost. Supply chain disruptions, fluctuating tariffs, and related increases in component and labor costs made the PPAs too costly to move forward.

Third, Sierra's compliance outlook is challenged by transmission constraints for Sierra. Currently, there is limited ability to move energy from generation 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.

***NV Energy RPS Compliance.*** To mitigate risks resulting in RPS non-compliance, Nevada Power and Sierra will continue to explore near-term options, including evaluating available proposals received from renewable energy RFPs, self-developing projects, discussions with counterparties to amend existing PPAs to facilitate acquisition of additional PCs, conducting bilateral asset purchase and other commercial transactions and exploring short-term purchase agreements that benefit customers, so that it can procure the renewable generation and BESS resources needed to continue meeting their RPS requirements.

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

***Renewable Resource Additions.*** The Companies require additional PCs to meet their RPS compliance obligations in the near term. The Companies hereby seek approval for 19 non-customer-specific bundled-load PPAs and four sleeved PPAs associated with customer energy agreements. The 19 non-customer-specific bundled-load PPAs represent sixteen projects that are comprised of 3,770 MW of solar PV and 4,805 MW of BESS output capacity, as well as 30 MW of geothermal, and the four sleeved PPAs associated with customer energy agreements represent 600 MW of PV and 600 MW of BESS, as well as 150 MW of geothermal projects.

## SECTION VII - SUMMARY OF ENERGY SUPPLY PLAN: NAC § 704.9215(f)

Pursuant to NAC § 704.9494, the Commission can determine that an Energy Supply Plan ("ESP") is prudent if the following requirements are met:

- The ESP balances the objectives of minimizing the cost of supply, minimizing retail price volatility, and maximizing the reliability of supply over the term of the plan.
- The ESP optimizes the value of the overall supply portfolio of the utility for the benefit of its bundled retail customers.
- The ESP does not contain any feature or mechanism that the Commission finds would impair the restoration of the creditworthiness of the utility or would lead to a deterioration of the creditworthiness of the utility.

The 2026 ESP is based on a specially prepared short-term load forecast. The 2026 ESP includes a power procurement plan, a fuel procurement plan, and a risk management strategy, each of which was prepared to comply with the requirements of NAC § 704.9494.

**Power Procurement/Sales Plan**

- Accept and approve the power procurement plan, which includes the following elements:
    - The Companies propose to continue the four-season laddering strategy to fill the remaining open positions in 2027 and 2028 and begin filling subsequent years' open positions. This plan is consistent with the laddering strategy for closing the open power position, which was most recently approved in Docket No. 25-08027. The power procurement laddering strategy will be executed in coordination with the physical gas procurement plan.
    - Efforts by the Companies to transact directly with counterparties as a supplement to the current request for proposal process to seek non-standard firm energy products in

an effort to address short-term supply challenges during the evening and overnight net demand peak period when solar resources are largely unavailable, given that battery storage is energy-limited.
    - A commitment by the Companies to continuously monitor the portfolio and seek to make short-term and forward purchases when economic or needed to serve native load. Any proposed purchases of greater than three years in duration will be submitted to the Commission for approval in accordance with NAC §§ 704.9113 and 704.9512.
    - A strategy and plan to make purchases and sales to optimize the value of the overall supply portfolio for the benefit of retail customers.
    - An obligation on behalf of the Companies to monitor their renewable portfolios on a continuous basis to ensure that sufficient renewable energy and PCs are maintained to comply with RPS and undertake cost-effective opportunities to fill new needs that may arise.
- Find, consistent with NAC § 704.9494(3), that the power procurement strategy is prudent.

**Physical Gas Procurement Plan**

- Accept and approve the Companies' plan to implement the four-season laddering strategy originally approved by the Commission in Docket No. 09-09001 to procure physical gas. Previously, the procurement of physical gas was subject to a cap on the premium, which could be exceeded with prior approval from the Companies' Risk Committee. Consistent with the Stipulation in Docket No. 09-09001, if the Companies exceeded the premium cap, and the procured gas that exceeded the premium cap was not the least cost supply alternative, they would provide written notice to the Regulatory Operations Staff of the Commission ("Staff") and the Bureau of Consumer Protection ("BCP"). The physical premium cap was originally approved in 2009 and has not been adjusted for inflation. The Companies propose that the physical premium cap be removed.
- Find, consistent with NAC § 704.9494(3), that the physical gas procurement strategy is prudent.

**Gas Transportation Plan**

- Accept and approve the gas transportation plan, which includes the following elements: Approval to maintain the Companies' current natural gas transportation portfolios. For Nevada Power, this requires authority to maintain seven existing gas transportation contracts with Kern River Pipeline and three with Southwest Gas Corporation. At Sierra, this requires authority to maintain a total of 37 existing gas transportation and storage contracts with TC Energy – Alberta, TC Energy – Foothills, TC Energy Gas Transmission Northwest ("GTN"), TC Energy Tuscarora Gas Transmission Company ("Tuscarora"), Great Basin Gas Transmission Company ("Great Basin"), Northwest Pipeline LLC ("NWPL"), Ruby Pipeline, and Pinyon Pipeline pursuant to rights of first refusal and

evergreen rights. The total projected annual costs for firm transportation contracts at both Nevada Power and Sierra are approximately $128.1 million.

- Find, consistent with NAC § 704.9494(3), that the gas transportation strategy is prudent.
- Accept and approve the need for additional firm interstate natural gas transportation capacity to support the Companies' Preferred Plan.[11]

**Gas Hedging Plan**

- Approval to continue the current hedging strategy and acquire no natural gas hedges covering the ESP Action Plan period. The Companies will continue to monitor the natural gas market fundamentals and recommend changes to the hedging strategy in a future ESP update or ESP amendment as necessary.
- The Companies will continue bi-annual workshops with Staff and BCP to review implementation of the approved no-hedge gas hedging strategy.
- An affirmative finding, consistent with NAC § 704.9494(3), that the Companies' gas hedging strategy is prudent.

**Risk Management Strategy**

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

***This 2026 ESP balances the objectives of minimizing the cost of supply, minimizing retail price volatility, and maximizing the reliability of supply over the term of the plan.*** Based on results of the production cost forecasting model, Figure S-20 shows the estimated cost-to-serve for the recommended unhedged scenario under base, high, and low fuel and purchased power pricing scenarios.

[11] The ESP Gas Transportation Plan discusses a gas pipeline expansion for the Fort Churchill generation additions requested under the Preferred Plan.

**FIGURE S-20**
**ESTIMATED COST TO SERVE (IN $000)**

| TOTAL FUEL AND PURCHASED POWER (F&PP) COSTS, EXCLUDING FIXED & VARIABLE OPERATIONS AND MAINTENANCE | | | |
|---|---|---|---|
| Year | Cost to Serve Assuming Low F&PP Prices (1,000s) (A) | Cost to Serve Assuming Base F&PP Prices (1,000s) (B) | Cost to Serve Assuming High F&PP Prices (1,000s) (C) |
| 2027 | $1,631,995 | $1,920,909 | $2,360,460 |
| 2028 | $1,835,971 | $2,143,071 | $2,627,658 |
| 2029 | $2,257,163 | $2,675,708 | $3,357,285 |

The Companies also calculated the projected Base Tariff Energy Rates ("BTERs") and Deferred Energy Accounting Adjustment ("DEAA") rates for 2027-2029 under the low, base, and high fuel and purchased power price forecasts. The projected BTER and DEAA rates, along with estimated carrying charges, are presented in Technical Appendix GAS-2.

The expected cost to serve and BTER remain within a reasonable band under the Companies' proposed procurement strategies. The ESP provides for the procurement of sufficient firm resources to ensure reliable service to retail customers.

The production cost, BTER, and DEAA calculations and analysis, show that this ESP balances the objectives of minimizing the cost of supply, minimizing retail price volatility, and maximizing the reliability of supply over the term of this plan.

***This 2026 ESP optimizes the value of the overall supply portfolio of the utilities for the benefit of their bundled retail customers***. The Companies will continue to monitor and adjust the power portfolio to identify and account for changes in load, cost, volatility, reliability, and other commercial or technical factors. Day-ahead, day-of, or month-ahead power purchases are expected to be made if there is an open position, or if system costs of decremental energy exceed the additional cost of market purchases. Similarly, day-ahead or day-of power sales are expected to be made as opportunities arise, including spot, fixed price, indexed agreements, or ancillary services products.

***This 2026 ESP does not contain any feature or mechanism that would impair the restoration of the creditworthiness of the utilities or would lead to a deterioration of the creditworthiness of the utilities***. Currently, the Companies are able to finance this ESP without impairing their creditworthiness, assuming timely recovery under the Commission's current rate recovery mechanisms.

## SECTION VIII – SUMMARY OF DISTRIBUTED RESOURCES PLAN: NAC § 704.9215(2)(g)

NRS § 704.741(5) sets forth six elements that must be included in a DRP. Each of these requirements is addressed in NV Energy's 2026 Joint DRP.

1) ***Locational Benefits and Costs of DERs***. NV Energy's Locational Net Benefits Analysis ("LNBA") was performed using a PWRR analysis as an integral component of the NWA analysis within the Grid Needs Assessment ("GNA") process. The Companies quantified numerous benefits and costs associated with DER, including: 1) transmission upgrade capital deferral value, 2) distribution upgrade capital deferral value, 3) transmission upgrade operation, maintenance, administrative and general ("OMAG") expense deferral value, 4) distribution upgrade OMAG expense deferral value, 5) avoided energy value, 6) avoided generation capacity value, 7) energy arbitrage value, 8) avoided transmission and distribution losses value, 9) renewable portfolio standard value, 10) avoided greenhouse gas emissions value, 11) avoided criteria air pollutants value, and 12) avoided transmission capacity value (as a sensitivity in the NWA analyses for distribution system constraints).

2) ***Tariffs, Contracts, or Other Mechanisms for Cost-Effective DER Deployment***. Non-wires DER solutions on the electric distribution system directed at addressing specific constraints and deferring planned wired solutions are new to NV Energy, and to many other utilities. The Companies support a measured approach but also advocate moving forward to vet these technologies in customer offerings to ensure that they provide their expected benefits, potentially facilitating customer bill savings, and do so safely and reliably under real-world conditions.

   The 2026 Joint DRP provides a brief update on NV Energy's pursuit of a first-of-its-kind hybrid remote microgrid solution on the Companies' electric distribution system in the Mt. Charleston area. The Companies are not seeking any Commission approval for this project in the DRP. The project is detailed in and any requests of the Commission related to it are made in NV Energy's Natural Disaster Protection Program filings. In addition, the 2026 Joint DRP requests Commission approval for a total of $2,840,000 for the years 2027 through 2029 to pursue an NWA Tariffed-on-Bill ("TOB") Pilot Program that is related to

two forecasted constraints on its distribution system that NV Energy has recommended pursuing non-wires solutions to alleviate.

3) ***Cost-Effective Coordination with Commission-approved Programs, Tariffs, and Incentives***. NV Energy's existing DSM, transportation electrification, and clean energy programs and related tariffs leverage several DER technologies, including: 1) EE, 2) DR, 3) solar PV, 4) EVs, 5) Electric Vehicle Supply Equipment (EVSE"), and 6) BESS. The integration of these programs has progressed with the DRP framework to provide benefits and lower cost for both NV Energy and its customers. Through geo-targeted deployment, these technologies support the locational benefits associated with mitigating certain forecasted constraints on the transmission and distribution systems. NV Energy performed its GNA, NWA analyses, and LNBA with these technologies embedded in the analyses of forecasted constraints on its electric transmission and distribution systems.

   NV Energy has incorporated several strategic integration and harmonization efforts across planning, program design, and operations. In DER planning, HCA and NWA analyses integrate historical results and future impacts of DER programs, including those in the DSM Plan. Recent enhancements include incorporating behind-the-meter ("BTM") solar and storage assets into the NWA analysis.

   NV Energy has further advanced a DER benefits harmonization effort between its LNBA methods and DSM cost-effectiveness testing via the introduction of new benefits into both the LNBA and the DSM valuation using the same methods. In addition, the proposed Grid Service Tariff Rider series filed with the Commission in Docket Nos. 25-10012 and 25-10013 for Nevada Power and Sierra, respectively, supports alignment of customer programs across the DSM, DRP, and TEP plans.

   Operationally, EE and DR programs now proactively support the distribution system through targeted customer recruitment in constrained areas and targeted dispatch of DR resources. These efforts are further enabled by major system upgrades under the Grid Ops initiative, including the implementation of a Distributed Energy Resource Management System ("DERMS"), which is designed to support programs across the DSM, DRP, and TEP plans.

4) ***Systems and Incremental Investment to Integrate Cost-Effective DERs***. In 2021, the Commission approved a centralized DERMS to develop the foundational technology required to efficiently manage a growing set of DERs and to explore the set of grid services that DERs could provide. NV Energy's DERMS is being implemented in multiple releases from 2020 through 2028. The 2026 Joint DRP narrative discusses the changes to the project plan since initial approval and the consequent effects of the project's budget. The

Companies are not seeking any additional approval from the Commission for this project in the 2026 Joint DRP but may do so in the future.

NV Energy was selected by the Department of Energy ("DOE") for award negotiations to develop a new set of grid services to be delivered from aggregated DERs in a distributed communications and control architecture. NV Energy negotiated a cooperative agreement with DOE for an award through July 2025. The Companies' cost share is approximately $2.76 million, which includes $376,000 for NV Energy's participation in the grant effort and $2.4 million for a 1 MW/4 MWh BESS to support the NWA and field demonstration. The 2026 Joint DRP narrative provides the project's status, actual expenditures, updated budget, and variances, and indicates that the project has been completed

NV Energy previously introduced its DER Analytics Toolset and Potential Study project (collectively, the "Project").[12] NV Energy executed a contract with Integral Analytics ("IA") in 2023 and IA subcontracted with E3 and Tierra Resource Consultants ("Tierra") to perform the DER MPS aspects of the Project and assist in DSM program development and cost-effectiveness calculations in support of its 2024 Joint IRP filing. More recently, NV Energy worked with IA utilizing the LoadSEER software (together with the DSMore software, comprising the "Toolset") to deliver an initial spatial DER forecast at the feeder level that was aligned with the data used in the Companies system-level 2026 IRP load forecast.

5) ***DER Barriers and Solutions***. NV Energy identified several potential barriers to the deployment of DERs related to 1) integration/interconnection with the distribution grid, 2) market limitations on the ability of DERs to deliver benefits, and 3) distribution system operational and infrastructure capability to handle DER value. The Companies determined how the DRP can help address these barriers and provide the status of each of these activities.

6) ***Transportation Electrification Plan ("TEP")***. The 2026 Joint TEP primarily focuses on the continuation of maximizing grid benefits for all customers by incentivizing the shifting of targeted EV charging loads to times that are most beneficial to the grid. The 2026 Joint TEP also includes customer education and outreach, pilot programs, and other key elements to advance transportation electrification in Nevada.

The 2026 Joint TEP covers transportation electrification programs and investments for the 2027 through 2029, with a total proposed budget of $16,931,000. It allows for enrollment of 8,281 ports in the Companies' managed charging programs and continues to educate and engage customers and community-based organizations about the benefits of managed

[12] Technical Appendix DRP Update-4 in Docket No. 23-09002 provided the scope of work for the Project.

charging. The development of the 2026 Joint TEP was informed by continuing discussions with stakeholders through quarterly meetings, lessons learned, and ongoing feedback from customers.

Related to its 2026 Joint TEP, NV Energy is requesting that the Commission approve its requests:

- for regulatory asset treatment for the cost recovery of the incentives and rebates only associated with its proposed TEP programs, totaling $4,676,000 for Nevada Power and $1,997,000 for Sierra for the 2026 Joint IRP three-year action plan period as summarized in TEP-Table 48 and TEP-Table 50 of the 2026 Joint DRP narrative;

- to expand the requirements for commercial customers who install EV charging infrastructure to receive 100 percent of the Rule 9 allowance up front; and

- to extend the date of the Nevada Power and Sierra Schedule No. ESB-V2G tariff to December 31, 2029, based on the reasons discussed in Section 10.E.2.c of the 2026 Joint DRP narrative.

NAC § 704.9215(2)(g) requires a DRP summary to contain:

1) a summary of the methods and outcomes of the hosting capacity analysis described by paragraph (b) of subsection 3 of NAC § 704.9237; and

2) a summary of forecasted loads and the forecasted growth of DERs for the electric grid over a six-year period, at minimum, beginning with the year after the DRP is filed.

***Hosting Capacity Analysis ("HCA")***. The HCA studies performed by NV Energy utilize two distinct systems: 1) the commercially-available Synergi Electric ("Synergi") electrical simulation software to model and analyze the Companies' electric distribution systems, and 2) NV Energy's Geographic Information System mapping system to provide the electrical connectivity models of the distribution systems from the substation transformer down to the primary node level that are used as the source for the connectivity models in Synergi.

Annually, the Companies perform a full-system HCA study process in first quarter of the year and monthly HCA updates the remainder of the year. The most recent full-system HCA study process was completed at the end of March 2026 and modeled existing and forecasted 2026-2035 conditions on the distribution system. In the 2026 Joint DRP narrative, NV Energy provides detailed explanation of the above activities, the HCA analytical method and outcomes, and its

monthly HCA update process satisfying the requirement for "real-time" data, with all the results and data publicly available via NV Energy's DRP web portal.

***Load and DER Forecasting***. NV Energy has a rigorous process for forecasting electric load growth on its distribution feeders and medium-power substation transformers, which is accomplished at the local level and then aggregated up to the substation level. No specific or new distribution facility load forecasts were produced for the 2026 Joint DRP. Rather, "snapshots" of the load forecasts in March 2026 that are updated daily by NV Energy's Distribution Planning department were used as the basis for the NWA analyses on the day each of those analyses were performed. The forecasts just prior to the full-system HCA study noted above were used in that study. Technical Appendix DRP-3 provides forecasted peak loads as of February 17, 2026, for 2026 through 2032 on NV Energy's substation transformers and feeders, covering the required minimum six-year timeframe following the year of the filing of the DRP.

NV Energy contracted with IA to achieve the scope of work for its DER Analytics Toolset and Potential Study effort. As noted in the 2026 Joint DRP narrative, NV Energy worked with IA utilizing the LoadSEER software to deliver an initial spatial DER forecast at the feeder level aligned with the system-level data used in the Companies' 2026 IRP load forecast, but vetted and used only the EE, DR, and BTM solar PV demand (MW) parts of that data in the performance of the NWA analyses in the DRP. NV Energy plans to vet and appropriately integrate the remaining spatial DER forecast data into its DRP analyses over the next year.

Finally, in compliance with paragraph 60 and ordering paragraph 17 of the Commission's December 27, 2024, order in Docket No. 24-05041, NV Energy has proposed NEM reliability impact thresholds, related tracking, communication protocol, and tariff revisions as detailed in Technical Appendix DRP-1 and seeks Commission approval of such.

## SECTION IX – A SUMMARY OF THE ACTIVITIES, ACQUISITIONS, AND COSTS INCLUDED IN THE ACTION PLAN OF THE UTILITY: NAC § 704.9215(2)(h)

The Companies seek Action Plan approval of several items, which, to implement the Preferred Plan, must be taken within the Action Plan period, January 1, 2027, through December 31, 2029. The Companies also seek Commission approval of actions as described in the ESP, which will be undertaken during the 2026 ESP period January 1, 2027, through December 31, 2029.

## SECTION X – INTEGRATED EVALUATION: NAC § 704.9215(2)(i)

In selecting its Preferred and Alternate plans, the Companies have evaluated various factors that are set forth in the Commission's regulations, including:

- The Present Worth Revenue Requirement for each alternative (see NAC § 704.937(3))

- The Present Worth of Societal Costs for each alternative (see NAC § 704.937(4))
- Whether the plan mitigates risk (see NAC § 704.937(6))
- Whether the plan provides adequate reliability (see NAC § 704.937(7)(a))
- Regulatory and financial constraints (see NAC § 704.937(7)(b))
- Whether the plan meets the RPS (see NAC § 704.937(7)(c))
- Whether the plan meets the requirements for environmental protection (see NAC § 704.937(7)(d))

In addition, NAC § 704.948 requires that "a utility shall analyze its decisions, taking into account its assessment of risk and identifying particular risks with respect to: (a) costs; (b) reliability; (c) finances; (d) the volatility of the price of purchased power and fuel; and (e) any other uncertainties the utility has identified."

In accordance with NAC § 704.948(2), the Companies considered the relationship among the factors used in selecting the Preferred and Alternate Plans, including the relationship between mitigating risk, minimizing cost and volatility, and maximizing reliability. The Companies selected Preferred and Alternate plans that provide the best combination of attributes, without assigning specific weights to any particular factor. Utilizing the results of the long-term load forecast and the Supply Plan, the Companies identified their resource requirements over the planning period. This analysis indicates that Nevada Power and Sierra need to add incremental supply side resources. The Companies developed five alternative plans for meeting its projected needs for incremental capacity and energy, from which Preferred and Alternate Plans were selected.

This 2026 Joint IRP demonstrates how the Companies intend to meet the state's policies and meet the energy demands of their customers while ensuring affordability, reliability, and flexibility. The Preferred Plan recommends the addition of 23 PPAs: 19 non-customer-specific bundled-load PPAs representing 13 projects that are comprised of 3,770 MW of solar photovoltaic PV energy and 4,805 MW of BESS output capacity, as well as 30 MW of geothermal energy, and four sleeved PPAs associated with customer energy agreements including 600 MW of solar PV and 600 MW of BESS, as well as 150 MW of geothermal projects. The Preferred Plan also recommends the addition of 401 MW of new simple cycle aeroderivative gas turbines at Fort Churchill Generation Station to be in-service in June 2030; an additional 401 MW of new simple cycle aeroderivative gas turbines at Fort Churchill Generation Station to be in-service in June 2031; 421 MW of new simple-cycle frame gas turbines at Fourt Churchill Generation Station to be in-service in June 2032; and transmission infrastructure associated with the renewable, storage, and thermal projects and required to meet customers' needs. The Preferred Plan—Obsidian— meets the systemwide planning reserve margin, strives to meet the combined state RPS mandate and company credit commitments (NGR, ESA, 704B obligations, and sleeved projects associated with customer service agreements), and targets the state's 2050 clean energy goal.

Prior to developing the Preferred Plan that addresses the needs of the Base Load Forecast, NV Energy responded to planning challenges in this 2026 Joint IRP through a deliberate, risk-aware planning framework anchored by the Large Load Electric Service Agreement (LLESAs) and a flexibility-focused preferred portfolio. The Companies employ resource planning analysis to isolate the incremental generation and transmission needs—and associated costs—that would not occur but for data-center load requests. This approach provides a transparent, fact-based foundation for aligning cost responsibility with cost causation and ensures that households, small businesses, and existing commercial and industrial customers are not asked to bear costs driven primarily by new large-load service.